ADEQ

A R K A N S A S
Department of Environmental Quality

NOV 1 8 2013

Kyle Wimsett, Environmental, Health, and Safety Manager
El Dorado Chemical Company
P.O. Box 231
El Dorado, AR 71730

Dear Mr. Wimsett:

The enclosed Permit No. 0573-AOP-R16 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 1/31/2013.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 0573-AOP-R16 for the construction, operation and maintenance of an air pollution control system for El Dorado Chemical Company to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

Mike Bates
Chief, Air Division

ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY
5301 NORTHSHORE DRIVE / NORTH LITTLE ROCK / ARKANSAS 72118-5317 / TELEPHONE 501-682-0744 / FAX 501-682-0880
www.adeq.state.ar.us

RESPONSE TO COMMENTS

EL DORADO CHEMICAL COMPANY
PERMIT #0573-AOP-R16
AFIN: 70-00040

On September 19, 2013, the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, written comments on the draft permitting decision were submitted by Jesslynn Spence, on behalf of the facility. The Department's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.

Comments # 1 through # 5 are general / global comments to be applied throughout the entire permit.

Comment #1:

The commenter requested a revision to all references to the existing DM Weatherly Nitric Acid Plant (SN-13) to read as DM Weatherly Nitric Acid Plant #1 (SN-13).

Response to Comment #1:

The permit has been updated as requested.

Comment #2:

The commenter requested revisions to the draft permit to make minor wording changes and to correct typographical errors as indicated in the actual permit text included in the submitted comment letter.

Response to Comment #2:

All appropriate changes were made.

Comment #3:

The commenter requested the addition of the following requirement to each specific condition requiring stack testing in the permit (as indicated in the affected Specific Conditions below):

> *"Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is*

conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above."

Response to Comment #3:

All testing requirements found in the draft permit were updated with the language requested by the commenter. Sources affected by this change include SN-05, SN-08, SN-09, SN-13, SN-14, SN-15, SN-17, SN-21, SN-35, SN-44, SN-49, SN-50, and SN-51.

Comment #4:

The commenter requested a revision to Section II: Ambient Air Impact Analysis to include the most recent results as submitted to the ADEQ on September 6, 2013.

Response to Comment #4:

All Ambient Air Impact Analysis information presented in the draft permit appears to contain all relevant and accurate information pertaining to the Ambient Air Impact Analysis. The commenter did not request any specific changes. The maximum modeled impact for the 1-hour NO_2 was updated to 276 $\mu g/m^3$. This occurred on Lion Oil property and was not considered ambient air. No other changes were made.

Comment #5:

The commenter requested the Department to revise the compliance condition references as listed in the Comment Letter.

Response to Comment #5:

All specific requests were addressed with each applicable comment.

Comment #6:

The commenter requested addition of "Appendix G – 40 CFR Part 63, Subpart CCCCCC" to the list of appendices included in the permit.

Response to Comment #6:

40 CFR Part 63, Subpart CCCCCC was added as Appendix I to the final permit.

Comment #7:

The commenter requested addition of the CEMS Monitoring Plan from the EPA/DOJ/LSB global settlement as Appendix J.

Response to Comment #7:

Appendix J has been added to the final permit as requested.

Comment #8:

The commenter requested a revision to the operating scenario description as indicated below. The commenter stated, "[b]ecause the emission reduction projects must be in place prior to the end of the contemporaneous period, the requirements in Operating Scenario # 1 will apply upon startup of that equipment."

The conditions of Operating Scenario # 2 shall apply to El Dorado Chemical Company until the Expansion Project has completed construction and has started operating. At that time, El Dorado Chemical Company shall cease operation under Operating Scenario # 2, and begin operations based on the conditions listed under Operating Scenario # 1. Some operations under Operating Scenario # 2 will no longer be applicable as existing sources are updated. <u>Also, as emissions reductions projects are completed for those sources included in the contemporaneous netting for particulate matter, the conditions of Operating Scenario # 1 shall apply upon startup.</u>

Response to Comment #8:

The permit has been updated as requested.

Comment #9:

The commenter requested a revision to the Summary of Permit Activity as indicated below to accurately reflect the proposed equipment changes that are included in this permit modification. The commenter noted that the Ammonia Plant Startup Heater (SN-54) has been deleted as a "new source" and added into the list of ancillary equipment/emission sources [associated] with the "used" ammonia plant. The commenter also stated that the Pease Anthony Scrubber (SN-17) that had previously been routed to the E2 Plant Brinks Scrubber would be removed. According to the commenter, the new brinks scrubber that will be installed at SN-05 is being designed to replace the control function of the Pease Anthony Scrubber.

> *El Dorado Chemical Company (EDCC) owns and operates a chemical manufacturing facility located at 4500 North West Avenue in El Dorado, Arkansas. EDCC submitted a prevention of significant deterioration (PSD) modification application to expand the facility. The PSD application included the following process equipment modifications:*
>
> 1. *Installation of a new DM Weatherly Nitric Acid Plant #2 (SN-59);*

2. *Installation of a new cooling tower (SN-60) to support DM Weatherly Nitric Acid Plant #2, ~~and~~ East Nitric Acid Plant, ~~and~~ West Nitric Acid Plant ~~operations~~, the NACSAC plant, and the Mixed Acid Plant; the existing cooling tower for the East and West Nitric Acid Plants (SN-42) will be removed from service;*

~~2.~~ 3. *Installation of three (3) new weak nitric acid storage tanks, which will be added to Nitric Acid Vent Collection System (SN-10);*

~~3.~~ 4. *Installation of a used Ammonia Plant and ancillary equipment (SN-49 through SN-51, and SN-54);*

~~4.~~ 5. *Installation of a new Ammonia Plant Cooling Tower (SN-52);*

~~5.~~ 6. *Installation of a new Ammonia Plant Ammonia Vent Flare (SN-53);*

~~6. Installation of a new Ammonia Plant Start-up Heater (SN-54);~~

7. *Installation of a new Ammonia Plant Process SSM Flare (SN-56) and a new Ammonia Storage Flare (SN-57);*
8. *Installation of a new ammonia storage tank, which will be added to ~~the~~ Ammonia Storage/Distribution (SN-32);*
9. *Installation of a new Ammonia Rail and Truck Loading (SN-58);*
10. *Installation of a new Start-up Boiler (SN-61);*
11. *Installation of a new ammonium nitrate neutralizer and chemical steam scrubber (SN-63);*
12. *Installation of a new E2 Ammonium Nitrate Brinks Scrubber (SN-05), which will control the existing emissions routed to SN-05 plus those from the E2 Ammonium Nitrate Prill Tower Fan (SN-06); the Pease Anthony Scrubber that had been in line with the existing SN-05 Brinks scrubber will be removed;*
13. *Installation of a new KT Ammonium Nitrate Brinks Scrubber (SN-14);*
14. *Installation of two (2) ammonium nitrate storage tanks, two (2) ammonium nitrate mix tanks, and a pH adjustment tank;*
15. *Installation of a new ammonium nitrate (solid prills) warehouse and associated handling equipment;*
16. *Installation of a new Nitric Acid Concentration (NACSAC) Plant (SN-47);*
17. *Removal of SN-06, as the emissions will now be routed to SN-05;*
18. *Removal of the two (2) existing boilers (SN-16A and SN-16B);*
19. *Removal of the UHDE Direct (Strong) Nitric Acid Plant (SN-22);*

~~19.~~ 20. *Removal of the Nitric Acid Loading (SN-29); loading emissions have been routed to the Nitric Acid Vent Collection System (SN-10);*

~~20.~~ 21. *Removal of the DSN Plant Cooling Tower (SN-39); and*

~~21.~~ 22. *Removal of the KT Plant Cooling Tower (SN-43).*

Response to Comment #9:

All of the changes requested will be made except for the statement of the removal of the Nitric Acid Loading (SN-29). The Department understands that the facility claims that these emissions are captured and routed to the Nitric Acid Vent Collection System (SN-10); however SN-29 is the source of these emissions and will remain in the permit.

Comment #10:

The commenter requested that the process description under Operating Scenario # 1 be updated to improve the accuracy of the process related information (as provided by EDCC staff) and to reflect CEMS monitoring requirements in the pending global settlement between the EPA/DOJ and LSB (EDCC's parent company).

Response to Comment #10:

The process description under Operating Scenario # 1 has been updated as requested.

Comment #11:

The commenter requested that the PSD summary under Operating Scenario # 1 be updated for accuracy purposes. According to the commenter, the proposed changes in the Project Emissions Increase totals reflect the updated Emission Calculations submitted to the ADEQ on September 12, 2013. In addition, the commenter requested the ADEQ to revise the dates defining the contemporaneous period, as indicated, to accurately reflect the latest project/permit projections.

Response to Comment #11:

The permit has been updated as requested.

Comment #12:

The commenter requested that the BACT Analysis be revised consistent with the latest updated version of the analysis submitted to the ADEQ on September 6, 2013.

Response to Comment #12:

There were no specific changes requested with Comment # 12 and the Department could not identify any inconsistencies; therefore, no changes were made.

Comment #13:

The commenter requested the Department to revise the list of criteria pollutants for which a BACT analysis is required consistent with the final significance analysis submitted as part of the PSD permit application.

Response to Comment #13:

The list of criteria pollutants subject to a BACT analysis has been updated to the following language as found on page 24 of the permit:

A BACT analysis has been provided for each new or physically modified emissions unit for each pollutant exceeding an applicable PSD SER, which includes carbon monoxide (CO), nitrogen oxides (NO_x), volatile organic compounds (VOC), sulfur dioxide (SO_2), and carbon dioxide equivalent (CO_2e). Per 40 CFR 52.21(j)(3), a BACT analysis is only provided for an emissions unit if the emissions unit also experiences a net emissions increase.

Comment #14:

The commenter requested the Department to delete the Uhde EnviNOx technology reference from Step 2, as this technology is feasible. The commenter noted that this revision is consistent with the updated BACT Analysis submitted to the ADEQ on September 6, 2013.

Response to Comment #14:

The permit has been updated as requested.

Comment #15:

The commenter requested that ADEQ revise Step 4 to include EDCC's original discussion of the Uhde EnviNO$_x$ technology, which is consistent with the updated BACT Analysis submitted to the ADEQ on September 6, 2013. The commenter maintained that the ability of the Uhde EnviNO$_x$ technology to control NO$_x$ emissions to the 5 ppmv level has not been confirmed relative to the inclusion of an acceptable margin of compliance, nor has the Uhde EnviNO$_x$ technology been demonstrated at the 5 ppmv level (with an acceptable margin of compliance) on a Weatherly, Inc. designed nitric acid plant.

Response to Comment #15:

The entire original discussion of the Uhde EnviNO$_x$ technology from the updated BACT Analysis submitted to the ADEQ on September 6, 2013 will not be added to the permit. The original statement was edited to only contain relevant information pertaining to a BACT Analysis.

The commenter's position regarding the ability of the Uhde EnviNO$_x$ technology to control NO$_x$ emissions to 5 ppm$_v$ is irrelevant. This technology is just a brand name for a generic Selective Catalytic Reduction (SCR) device. Furthermore, a review of the supporting documentation for the development of NSPS Ga indicates that SCR has been successfully implemented as a control device for NO$_x$ at Nitric Acid Production facilities, emission data are consistent across a 30 day period, and existing SCR can achieve a level lower than 5 ppm$_v$. In this case, Iowa Fertilizer was issued a permit with a 5 ppm$_v$ (30-day rolling average not including SSM). Given the fact that the 5 ppm$_v$ does not include periods of SSM, this limit is providing what the commenter is calling "an acceptable margin of compliance."

Comment #16:

The commenter requested that the BACT Analysis summary for SN-59 be updated based on the BACT Analysis submitted to the ADEQ on September 6, 2013. The commenter maintained that significant uncertainty exists relative to the ability of catalytic reduction to achieve a 5 ppmv NO$_x$ limit with an acceptable margin of compliance considering site specific operational/equipment variability factors over the long term. The commenter requested that the ADEQ reconsider its position relative to an adjustable limit/operational study approach that would result in an accurate, statistically based BACT limit and averaging period. The commenter provided the ADEQ with supporting regulatory references in the BACT Analysis for an adjustable limit approach. The commenter contended that the ADEQ has the authority to pursue such an alternative BACT limit approach in a case where a BACT limit has been included in an issued permit, but has not been demonstrated to a degree that removes compliance related uncertainty, as addressed in the NSR Manual and supported by a 2006 EPA Environmental Appeals Board decision.

Response to Comment #16:

The commenter is improperly trying to use information provided in the 2006 EPA Environmental Appeals Board decision. The case presented involved permitting of particulate matter emissions.

Specifically, there was a BACT limit issued for PM_{10} that did not establish a limit for filterable PM_{10} and condensable PM_{10} emissions. Without knowing the contribution of each type of particulate matter emissions to the BACT limit, the permitting agency did not believe that the limit was appropriate and granted a higher BACT limit, to be adjusted downward once the different particulate matter emission contributions were determined. The original permit did not authorize any alternative limit; the revised limit was based on a second permit application and review.

Other permit examples cited by the commenter do not authorize relaxed BACT limits. Instead, the permit examples establish a BACT limit and the facility is required to investigate the capability of establishing lower limits.

In summary, there is no precedence for adjustable BACT limits in a permit and the BACT analysis supports the permit limit, as is.

Comment #17:

The commenter requested that the ADEQ revise the referenced NO_x emission limits as indicated below, which is consistent with vendor information.

The concentrations for NO_x converted to ~~a~~ mass rates are 33.78 lb/hr (3-hour average inclusive of SSM), ~~3.45~~3.38 lb/hr (30-day rolling average excluding SSM), 26.35 lb/hr (30-day rolling average including SSM), and 17.76 tpy (rolling 12-month average). The corresponding production based limits are 0.64 lb/ton (3-hour average including SSM), ~~0.065~~0.064 lb/ton (30-day rolling average excluding SSM), 0.5 lb/ton (30-day rolling average including SSM), and 0.078 lb/ton (rolling 12-month average including SSM).

Response to Comment #17:

The permit has been updated as requested.

Comment #18:

The commenter requested that the BACT Analysis summary for SN-59 be updated based on the BACT Analysis submitted to the ADEQ on September 3, 2013. The commenter maintained that significant uncertainty exists relative to the ability of catalytic reduction to achieve a 30 ppmv N_2O limit with an acceptable margin of compliance considering site specific operational/equipment variability factors over the long term. The commenter requested that the ADEQ reconsider its position relative to an adjustable limit/operational study approach that would result in an accurate, statistically based BACT limit. The commenter stated that the N_2O BACT limit issue is similar to the NO_x BACT limit issue in Comment 12 above.

Response to Comment #18:

The Department's position regarding an "adjustable" BACT limit remains the same. The case that the commenter cited is not applicable to the BACT determination for this permit. The N_2O limit will remain as written in the draft permit. See Response to Comment #16.

Comment #19:

The commenter requested that the ADEQ revise the referenced NO_x emission limits as indicated below, which is consistent with vendor information.

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-59	*DM Weatherly Nitric Acid Plant # 2*	*Opacity*	*SCR with extended absorption, good and efficient operating practices*	*0%*
		NO_x		*100 ppm_v (3-hr average including SSM)* *0.64 lb/ton (3-hr average including SSM)* *33.78 lb/hr (3-hr average including SSM)* *5 ppm_v (Rolling 30-day average excluding SSM)* *~~0.065~~0.064 lb/ton (Rolling 30-day average excluding SSM)* *~~3.45~~3.38 lb/hr (Rolling 30-day average excluding SSM)* *0.5 lb/ton of 100% Nitric Acid (Rolling 30-day average including SSM)* *26.35 lb/hr (Rolling 30-day average including SSM)* *6 ppm_v (Rolling 12 months including SSM)* *17.76 tons per rolling 12 months (Including SSM)*
		GHG	*Tertiary catalytic reduction*	*N_2O 30 ppm_v (3-hr average)* *N_2O 0.39 lb/ton (3-hr average)* *N_2O 20.6 lb/hr (3-hr average)* *N_2O 98% destruction efficiency* *N_2O 90.04 tons per rolling 12 months* *CO_2e 27,911.28 tons per rolling 12 months*

Response to Comment #19:

The permit has been updated as requested.

Comment #20:

The commenter requested that the ADEQ revise Step 4 to include the additional language indicated below. The commenter stated that this information was submitted to the ADEQ in response to BACT limit related questions posed during the draft permit development phase and was needed to further support why the proposed BACT limit for NO_x was not as low as the lowest entry in the EPA's RBLC.

The reformer permitted at the Chevron Plant (CA-1121) is not in operation in an ammonia manufacturing plant. The reformer at Chevron ~~is a~~utilizes catalytic reforming, whereas, the reformer at EDCC will be a steam methane reformer. Therefore, the two reformers are not comparable. Note also that in the Iowa Fertilizer Plant permit, information states that only natural gas will be used as fuel to the reformer. At EDCC, the primary reformer will fire natural gas and purge gas from the ammonia manufacturing process. This purge gas contains up to 5% ammonia, which could be converted to NO_x in the combustion reaction. Considering that statement, the NO_x BACT limit proposed for SN-49, which is the same as that for the Iowa facility, could be considered more conservative.

Response to Comment #20:

The permit has been updated as requested.

Comment #21:

The commenter requested that the ADEQ revise the BACT limits in Step 5 and the BACT Summary Table as indicated below. The commenter stated that the revised limits are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

Step 5: Select BACT

BACT for GHG control for the primary reformer is expected to incorporate elements of combustion control that reduce CO_2 emissions, yet do not impact the process. Prior to implementation, LSB will develop a work plan outlining the energy efficiency design elements. Once these final design elements are put into practice, LSB, where practicable will maintain a continuous record of set points that directly correlate to fuel usage and CO_2 emissions from the primary reformer.

The facility has proposed a BACT limit of ~~0.0006~~0.00022 lb/MMBtu for N_2O, 0.0022 lb/MMBtu for Methane, and 117 lb/MMBtu for CO_2. ~~All of the emission calculations provided by the facility were based on 0.0002 lb/MMBtu for N_2O, and this is the same limit that a similar plant has taken recently. Therefore, the facility will be assigned a BACT limit of 0.0002 lb/MMBtu for N_2O.~~ These rates equal 0.18 lb/hr for N_2O, 1.82 lb/hr for Methane, and 96,643.5 lb/hr for CO_2. All short-term limits are based on a 3-hour averaging period. The annual BACT limit for CO_2e is 423,714.2 tpy on a rolling 12-month basis.

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-49	*Ammonia Plant Primary Reformer (824 MMBtu/hr natural gas-fired reformer with SCR)*	*Opacity*	*Combustion of natural gas and process off gas (purge gas), and good and efficient combustion practices*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average)* *0.61 lb/hr (3-hr average)* *0.44 tons per rolling 12 months*
		VOC		*0.0014 lb/MMBtu (3-hr average)* *1.15 lb/hr (3-hr average)* *5.05 tons per rolling 12 months*
		CO		*0.0194 lb/MMBtu (3-hr average)* *15.99 lb/hr (3-hr average)* *70.02 tons per rolling 12 months*
		NO_x	*SCR*	*0.0124 lb/MMBTU (3-hr average)* *10.22 lb/hr (3-hr average)* *44.75 tons per rolling 12 months*
		GHG	*Good operating practices*	CO_2 *117 lb/MMBTU (3-hr average)* CH_4 *0.0022 lb/MMBTU (3-hr average)* N_2O *0.00022 lb/MMBTU (3-hr average)* CO_2e *423,714.2 tons per rolling 12 months*

Response to Comment #21:

The permit has been updated as requested.

Comment #22:

The commenter requested that the ADEQ revise the process related description as indicated below. The commenter stated that for SN-50, the CO_2 comes from the condensate flash tank, not the CO_2 Regenerator.

CCS is being used in pilot-scale projects and is not currently in use in large-scale applications. Although there continues to be the development of proprietary solvents which facilitates the absorption of CO_2, CCS technologies are not yet commercially available for process sources. Furthermore, there is not currently a nearby CO_2 storage reservoir to utilize for the CO_2 captured from the ~~regenerator~~condensate flash tank. Additionally, there are no nearby industries that could utilize the CO_2 for carbonation. Therefore, CCS is considered to be technically infeasible.

Response to Comment #22:

The permit has been updated as requested.

Comment #23:

The commenter requested that the following sentence be deleted from Step 5 of the BACT Analysis for SN-50:

Because there are currently no technically feasible control options, this step of the BACT process is not required.

Response to Comment #23:

The sentence has been removed as requested.

Comment #24:

The commenter requested that Step 5 of the BACT Analysis for SN-51 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient operation as BACT for CO emissions at the CO_2 regenerator at the ammonia plant. The BACT limits for this source include 0.02 lb CO/ton of NH_3 production on a 3-hr average, 1.46 lb/hr CO on a 3-hr average, and 6.41 tons of CO per rolling 12 months. EDCC proposes a BACT limit of ~~0.02~~0.01 lb CO/ton of ammonia produced on a 3-hour average basis.

Response to Comment #24:

The inclusion of 0.01 lb CO/ton of ammonia produced in this comment was an error on the part of the commenter. The BACT limit of 0.02 lb CO/ton of NH_3 production as contained in the draft permit is correct. Also, the commenter's hourly and annual limits for this source are incorrect. After applying the 0.02 lb CO/ton of NH_3 production (3-hr average), the CO emissions from SN-51 should be 1.17 lb/hr and 5.11 tons per rolling 12 months. The permit will be updated with these values.

Comment #25:

The commenter requested that Step 5 of the BACT Analysis for SN-51 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient operation as BACT for VOC emissions at the CO_2 regenerator at the ammonia plant. The BACT limits for this source include 0.106 lb VOC/ton of NH_3 production on a 3-hr average, 33.64 lb/hr VOC on a 3-hr average, and 147.35 tons of VOC per rolling 12 months.~~EDCC proposes a BACT limit of 0.106 lb VOC/ton of ammonia produced on a 3-hour average basis.~~

Response to Comment #25:

The permit has been updated as requested.

Comment #26:

The commenter requested that Step 5 of the BACT Analysis and the BACT Summary Table for SN-51 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

Because there are currently no technically feasible control options, this step of the BACT process is not required. The BACT limits for this source include ~~1.26~~2,507.5 lb CO_2/ton of NH_3 production on a 3-hr average, ~~147,000~~146,262.53 lb/hr CO_2 on a 3-hr average, and ~~643,860~~640,669.20 tons of CO_2/CO_2e per rolling 12 months.

BACT Analysis Summary				
Source	Description	*Pollutant*	*Control Technology*	*BACT Limit*
SN-51	*Ammonia Plant CO_2 Regenerator*	*VOC*	*Good and efficient operating practices*	*0.106 lb/ton of NH_3 produced (3-hr average)* *33.64 lb/hr (3-hr average)* *147.35 tons per rolling 12 months*
		CO		*0.02 lb/ton of NH_3 produced (3-hr average)* *~~7.31~~1.46 lb/hr (3-hr average)* *~~32.03~~6.41 tons per rolling 12 months*

		GHG		*CO_2 ~~1,262~~2,507.5 lb/ton of NH_3 produced (3-hr average)* *~~147,000~~146,262.53 lb/hr CO_2 (3-hr average)* *CO_2/CO_2e ~~643,860~~640,669.20 tons per rolling 12 months*

Response to Comment #26:

After applying the 0.02 lb CO/ton of NH_3 production (3-hr average), the CO emissions from SN-51 should be 1.17 lb/hr and 5.11 tons per rolling 12 months (See Response to Comment # 24). The GHG BACT limits have been updated as requested.

In addition, the statement "*Because there are currently no technically feasible control options, this step of the BACT process is not required*" will be deleted from step 5 because this is untrue.

Comment #27:

The commenter requested that the ADEQ revise the BACT limits in Step 5 and the BACT Summary Table as indicated below. According to the commenter, the proposed changes are consistent with the origin of other emission sources within the table, the updated Emission Calculations submitted to the ADEQ on September 12, 2013, and the ADEQ's rounding conventions.

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-53	*Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)*	*Opacity*	*Combustion of Natural gas and Good Combustion Practice*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average) from pilot* *0.00077 lb/hr (3-hr average)* *0.0034 tons per rolling 12 months*
		VOC		*0.0054 lb/MMBtu (3-hr average) from pilot* *0.0057 lb/hr (3-hr average)* *0.025 tons per rolling 12 months*

		CO		*0.082 lb/MMBtu (3-hr average) from pilot* *0.087 lb/hr (3-hr average)* *0.38 tons per rolling 12 months*
		NO_x		*0.098 lb/MMBtu (3-hr average) from pilot* *792.03 lb/hr (3-hr average based on 0.5% conversion of NH_3 to NO_x* ~~*719.66*~~*6.9 tons per rolling 12 months*
		GHG		*CO_2 117 lb/MMBtu (3-hr average)* *CH_4 0.0022 lb/MMBtu (3-hr average)* *N_2O 0.00022 lb/MMBtu (3-hr average)* *CO_2e* ~~*423,714.2*~~*719.87 tons per rolling 12 months*

Response to Comment #27:

The permit has been updated as requested.

Comment #28:

The commenter requested that Step 5 of the BACT Analysis for SN-54 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected the use of low-NO_x burners and good and efficient combustion as BACT for NO_x emissions at the startup heater. The BACT limits for this source include 0.06 lb NO_x/MMBtu per hour heat input at the startup heater on a 3-hr average, 2.28 lb/hr NO_x on a 3-hr average, and 0.57 tons of NO_x per rolling 12 months.

Response to Comment #28:

The permit has been updated as requested.

Comment #29:

The commenter requested that Step 5 of the BACT Analysis for SN-54 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient combustion as BACT for CO emissions at the startup heater. The BACT limits for these sources include 0.01 lb CO/MMBtu per hour heat input at the heater on a 3-hr average, 0.38 lb/hr CO on a 3-hr average, and 0.10 tons of CO per rolling 12 months.~~EDCC proposes a BACT limit of 0.01 lb CO/MMBtu per hour heat input at the heater on a 3-hour average basis, or 12.38 ppm~~$_{vd}$ ~~@ 3% O~~$_2$~~.~~

Response to Comment #29:

The permit has been updated as requested.

Comment #30:

The commenter requested that Step 5 of the BACT Analysis for SN-54 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient combustion as BACT for VOC emissions at the ammonia plant start-up heater. The BACT limits for these sources include 0.002 lb VOC/MMBtu per hour heat input at the startup heater on a 3-hr average, 0.08 lb/hr VOC on a 3-hr average, and 0.019 tons of VOC per rolling 12 months. ~~EDCC proposes a BACT limit of 0.002 lb VOC/MMBtu per hour heat input at the start-up heater, on a 3-hour average basis, or 4.33 ppm~~$_{vd}$ ~~@ 3% O~~$_2$~~.~~

Response to Comment #30:

The permit was updated as requested.

Comment #31:

The commenter requested that Step 5 of the BACT Analysis for SN-54 be updated based on the Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient combustion and the use of low sulfur fuel as BACT for the startup heater. The BACT limits for these sources include 0.00074 lb SO_2/MMBtu per hour heat input at the startup heater on a 3-hr average, 0.028 lb/hr SO_2 on a 3-hr average, and 0.0070 tons of SO_2 per rolling 12 months.~~EDCC proposes a BACT limit of 0.00074 lb SO~~$_2$~~/MMBtu at the startup heater, on a 3-hour average basis.~~

Response to Comment #31:

The permit has been updated as requested.

Comment #32:

The commenter requested a revision of the BACT limits in Step 5 and the BACT Summary Table as indicated below. The commenter stated that the proposed changes are consistent with the origin of other emission sources within the table, the updated Emission Calculations submitted to the ADEQ on September 12, 2013, and the ADEQ's rounding conventions. Also, the commenter proposed the deletion of the concentration limits for VOC and CO, because the mass based limits are sufficient for

BACT compliance demonstration purposes. The commenter stated that mass based BACT limits for VOC and CO are also consistent with the unit basis for the SO_2 and NO_x limits.

In summary, BACT for GHG control for the start-up heater is anticipated to include firing only natural gas and inherent design specifications to meet the aforementioned limit. CO_2 emissions from the start-up heater may not exceed 117 lb MMBtu/hr based on three 1-hour stationary source testing runs utilizing USEPA Method 3A. Methane BACT limits for the start-up heater may not exceed 0.0022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 18. Also, the N20 emissions from the start-up heater may not exceed 0.00022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 320. In addition, the total CO_2e emissions of 1,115.3 tons per 12-month rolling averaging period shall not be exceeded. ~~Methane BACT limits will be set at 0.0022 lb/MMBtu and 0.09 lb/hr on a 3-hr average. N_2O BACT limits will be set at 0.0002 lb/MMBtu and 0.009 lb/hr on a 3-hr average.~~

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
54	*Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)*	*Opacity*	*Combustion of Natural gas and Good Combustion Practice*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average) 0.03 lb/hr (3-hr average) 0.007 tons per rolling 12 months*
		VOC		*0.002 lb/MMBtu (3-hr average) ~~4.33 ppm_{vd} @ 3% O_2~~ ~~0.19~~0.08 lb/hr (3-hr average) ~~0.048~~0.019 tons per rolling 12 months*
		CO		*0.01 lb/MMBtu (3-hr average) ~~12.38 ppm_{vd} @ 3% O_2~~ ~~0.76~~0.38 lb/hr (3-hr average) ~~0.19~~0.10 tons per rolling 12 months*
		NO_x	*Low NO_x burners Combustion of clean fuel Good Combustion Practices*	*0.06 lb/MMBtu (3-hr average) 2.28 lb/hr (3-hr average) 0.57 tons per rolling 12 months*

		GHG	Good operating practices	CO_2 117 lb/MMBtu CH_4 0.0022 lb/MMBtu N_2O 0.00022 lb/MMBtu CO_2e ~~20,569~~1,115.31 tons per rolling 12 months

Response to Comment #32:

The concentration limits for VOC and CO in the BACT Analysis summary for SN-54 has been updated as requested. The short-term and annual limits for VOC and CO have not been updated as requested. A review of the material submitted on September 12, 2013 indicates that the draft permit already contains the appropriate limits, and the commenter is incorrect in proposing a different limit. The GHG limits have been updated as requested.

Comment #33:

The commenter requested that the entire BACT analysis section for the Ammonia Plant SSM Flare (SN-56) and Ammonia Storage Flare (SN-57) be updated consistent with the BACT Analysis submitted to the ADEQ on September 6, 2013.

Response to Comment #33:

All of the requested wording changes were made except for the request to update the Opacity limit from 0% to 5%. During the review process, the facility accepted an opacity limit of 0%, which is consistent with other flare opacity limits found in the RBLC. The opacity limit will remain as written in the draft permit, i.e. 0%.

Comment #34:

The commenter requested revision of the BACT limits in the BACT Summary Table as indicated below. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

A summary of the BACT limits for SN-56 can be found in the following table:

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-56	*Ammonia Plant Process SSM Flare*	*Opacity*	*Combustion of Natural gas and Good Combustion Practice*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average) 0.00070 lb/hr (3-hr average) 0.0031 tons per rolling 12 months*

		VOC		*0.0054 lb/MMBtu (3-hr average)* *0.0051 lb/hr (3-hr average)* *0.023 tons per rolling 12 months*
		CO		*0.082 lb/MMBtu (3-hr average) from pilot* *156.~~08~~10 lb/hr (3-hr average based on 98% control of process gas* *39.36 tons per rolling 12 months*
		NO_x		*0.098 lb/MMBtu (3-hr average)* *0.093 lb/hr (3-hr average)* *0.41 tons per rolling 12 months*
		GHG		*CO_2 117 lb/MMBtu (3-hr average)* *CH_4 0.0022 lb/MMBtu (3-hr average)* *N_2O 0.00022 lb/MMBtu (3-hr average)* *CO_2e 5,179.78 tons per rolling 12 months*~~*CO_2 18,742.8 lb/hr (3-hr average based on 98% control of process gas)*~~ ~~*CH_4 2.11 lb/hr (3-hr average based on 98% control of process gas)*~~ ~~*N_2O 0.00021 lb/hr (3-hr average)*~~ ~~*CO_2e 5,179.8 tons per rolling 12 months*~~

Response to Comment #34:

The permit has been updated as requested.

Comment #35:

The commenter requested revision of the BACT limits in the BACT Summary Table as indicated below. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

A summary of the BACT limits for SN-57 can be found in the following table:

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-57	*Ammonia Storage Flare*	*Opacity*	*Combustion of natural gas, and good and efficient operating practices*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average)* *0.00015 lb/hr (3-hr average)* *0.00056 tons per rolling 12 months*
		VOC		*0.0054 lb/MMBtu (3-hr average)* *0.0011 lb/hr (3-hr average)* *0.0041 tons per rolling 12 months*
		CO		*0.082 lb/MMBtu (3-hr average)* *~~0.02~~0.017 lb/hr (3-hr average)* *0.063 tons per rolling 12 months*
		NO_x		*0.098 lb/MMBtu (3-hr average) from pilot* *10.02 lb/hr (3-hr average based on 0.5% conversion of NH_3 to NO_x)* *43.88 tons per rolling 12 months*

		GHG		*CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 89.99 tons per rolling 12 months*

Response to Comment #35:

The permit has been updated as requested.

Comment #36:

The commenter requested updates to the control technology descriptions in Steps 3, 4, and 5 as indicated below for SN-61. The commenter stated that these changes are consistent with the updated BACT Analysis submitted to the ADEQ on September 6, 2013.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Use of low NO_x burners with flue gas recirculation at the boiler~~proper and efficient combustion at the boiler~~ is the only feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Flue gas recirculation and low NO_x burners are the most effective controls NO_x emissions at the startup boiler.
~~Good and efficient combustion of the startup boiler while utilizing low NO_x burners is the only utilized and most effective for the control of NO_x emissions.~~

Response to Comment #36:

The permit has been updated as requested.

Comment #37:

The commenter requested updates to the BACT limits in Step 5 as indicated below for SN-61. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

Step 5: Select BACT

EDCC has selected low NO_x, combustion efficient burners with flue gas recirculation~~good and efficient combustion~~ as BACT for NO_x emissions at the startup boiler. The BACT limits for this source include 0.018 lb NO_x/MMBtu per hour heat input at the startup boiler on a 3-hr average, 4.32 lb/hr NO_x on a 3-hr average, and under Operating Scenario # 1, 18.92 tons of NO_x per rolling 12 months. Under Operating Scenario # 2, the annual limit will reduce to 5.68 tons of NO_x per rolling 12 months. ~~EDCC proposes a BACT limit of 0.018 lb NOx/MMBtu per hour heat input at the startup boiler, on a 3-hour average basis.~~ The facility proposed two (2) operating scenarios for this boiler. One operating scenario was listed with the boiler operating at maximum capacity annually, and the other as a high turndown rate (10:1) boiler. The facility based their BACT analysis on operating the boiler with a high turndown rate, and chose limits based on this fact. Therefore, the other operating scenario is not feasible with a high turndown rate boiler. Not operating the boiler at a high turndown rate would constituent a change in the method of operation for the unit.

Response to Comment #37:

The permit has been updated as requested.

Comment #38:

The commenter requested updates to the BACT limits in Step 5 as indicated below for SN-61. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for CO emissions at the startup boiler. The BACT limits for this source include 0.037 lb CO/MMBtu per hour heat input at the boiler on a 3-hr average basis, or 50 ppm_{vd}, 8.88 lb/hr CO on a 3-hr average, and under Operating Scenario # 1, 38.89 tons of CO per rolling 12 months. Under Operating Scenario # 2, the annual limit will be reduced to 11.67 tons of CO per rolling 12 months.~~EDCC proposes a BACT limit of 0.037 lb CO/MMBtu per hour heat input at the boiler, on a 3-hour average basis, or 50 ppmvd.~~

Response to Comment #38:

The permit has been updated as requested.

Comment #39:

The commenter requested updates to the BACT limits in Step 5 as indicated below for SN-61. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient combustion as BACT for VOC emissions at the start-up boiler. The BACT limits for this source include 0.004 lb VOC/MMBtu per hour heat input at the startup boiler on a 3-hr average, 0.96 lb/hr VOC on a 3-hr average basis, and under Operating Scenario # 1, 4.21 tons of VOC per rolling 12 months. Under Operating Scenario # 2, the annual limit is reduced to 1.26 tons of VOC per rolling 12 months.

Response to Comment #39:

The permit has been updated as requested.

Comment #40:

The commenter requested updates to the BACT limits in Step 5 as indicated below for SN-61. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

EDCC has selected good and efficient combustion and the use of low sulfur fuel as BACT for the startup boiler. The BACT limits for this source include 0.00074 lb SO_2/MMBtu at the startup boiler on a 3-hr average basis, 0.18 lb/hr SO_2 on a 3-hr average basis, and under Operating Scenario # 1, 0.77 tons of SO_2 per rolling 12 months. Under Operating Scenario # 2, the annual limit is reduced to 0.23 tons of SO_2 per rolling 12 months.

Response to Comment #40:

The permit has been updated as requested.

Comment #41:

The commenter requested updates to the BACT limits in Step 5 as indicated below for SN-61. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

In summary, BACT for GHG control for the start-up boiler is anticipated to include firing only natural gas and inherent design specifications to meet the aforementioned limit. CO_2 emissions from the startup boiler may not exceed 117 lb MMBtu/hr based on three 1-hour stationary source testing runs utilizing USEPA Method 3A. Methane BACT limits for the startup boiler may not exceed 0.0022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 18. Also, the N20 emissions from the start-up boiler may not exceed 0.00022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 320. In addition, under Operating Scenario # 1 the total CO_2e

<u>emissions of 123,410.99 tons per 12-month rolling averaging period shall not be exceeded. Under Operating Scenario # 2, the annual limit is reduced to 37,023.69 tons per 12-month rolling averaging period.</u>

Response to Comment #41:

The permit has been updated as requested.

Comment #42:

The commenter requested revision of the BACT limits in the BACT Summary Table as indicated below. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013. Also, the commenter requested a revision of the control technology description NO_x as indicated. According to the commenter, this change is consistent with the updated BACT Analysis submitted to the ADEQ on September 6, 2013.

A summary of the BACT limits for SN-61 can be found in the following table:

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-61	*Start-up Boiler (240 MMBtu/hr)*	*Opacity*	*Combustion of natural gas, and good and efficient operating practices*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average) 0.18 lb/hr (3-hr average) 0.23 tons per rolling 12 months*
		VOC		*0.004 lb/MMBtu (3-hr average) 0.96 lb/hr (3-hr average) 1.26 tons per rolling 12 months*
		CO		*0.037 lb/MMBtu (3-hr average) 8.88 lb/hr (3-hr average) 11.67 tons per rolling 12 months*

		NO_x	*Low NOx burners and flue gas recirculation at the boiler* *Combustion of clean fuel* *Good Combustion Practices*	*0.018 lb/MMBtu (3-hr average)* *4.32 lb/hr (3-hr average)* *5.68 tons per rolling 12 months*
		GHG	*Good operating practices*	*CO_2 117 lb/MMBtu* *CH_4 0.0022 lb/MMBtu (3-hr average)* *N_2O 0.00022 lb/MMBtu (3-hr average)* *CO_2e 37,023.69 tons per rolling 12 months*

Response to Comment #42:

The permit has been updated as requested.

Comment #43:

The commenter requested the addition of NESHAP Subpart CCCCCC to the list of regulations applicable to the Expansion Project Operating Scenario.

Response to Comment #43:

After the expansion project is completed, the facility will be a major source for hazardous air pollutants. NESHAP Subpart CCCCCC only applies to area sources; therefore, the permit will not be updated as requested, and will remain as written in the draft permit.

Comment #44:

The commenter requested that the Emission Summary Table for the Expansion Project Operating Scenario be updated consistent with the emission calculations submitted to the ADEQ on September 12, 2013.

Response to Comment #44:

The emission summary table has been updated as needed.

Comment #45:

The commenter requested a revision of the process description for SN-08 and SN-09 to reference operation of the NO_x CEMS according to the CEMS Monitoring Plan is an element of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company.

According to the commenter, the East and West Nitric Acid Plants are covered sources in the global settlement.

Response to Comment #45:

The permit has been updated as requested.

Comment #46:

The commenter proposed that Specific Condition 1 include the compliance demonstration requirements consistent with changes made in a redline strikethrough version of the draft permit. The commenter stated that this change is consistent with EDCC's proposed deletion of the CEMS monitoring requirement for N_2O.

Response to Comment #46:

The requested changes were not made. The compliance mechanisms in the draft permit are sufficient and do not need to be changed. ADEQ does not agree to the removal of CEMs. Each of the requested changes will be addressed in the appropriate responses below.

Comment #47:

The commenter requested the removal of the hourly production limits for SN-08 and SN-09, and related compliance record keeping requirement in Specific Conditions 4 and 6, respectively, of the draft permit. The commenter stated that the short term emission limits (i.e., lb/hr limits) for SN-08 and SN-09 are based on the maximum capacity of the equipment/process. According to the commenter, considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #47:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity of 152,387.5 ton/yr and dividing by 8,760 hours per year of operation. This short term number does not represent a realistic short term maximum capacity for these sources as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for these sources.

Comment #48:

The commenter requested the removal of the N_2O CEMS monitoring requirement for SN-08 and SN-09. According to the commenter, there are currently no health based emission standards for GHG pollutants that would warrant the need for continuous monitoring, and there are no underlying federal regulatory requirements for the continuous monitoring of GHG emissions. The commenter stated that the proposed emission limits for N_2O are based on factors developed from annual testing required by the GHG Reporting Rule. According to the commenter, the results for SN-08 and SN-09 have been consistent, with no significant variability, thus indicating that continuous monitoring would serve no useful purpose. In addition, the commenter stated that the installation, operation, and maintenance of a CEMS in this instance places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #48:

Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. The commenter's statement regarding health based emission standards for GHG pollutants is irrelevant, and the statement that there are no underlying federal regulatory requirements is false. This source is a major source for GHG, and is subject to the requirements of the PSD rules found in 40 CFR 52.21. The PSD rules require the permit to include methods for determining compliance with the terms of the permit. The commenter has repeatedly stated that there will be process inconsistency due to operational/equipment variability. There is no information available to indicate that these emissions are not consistent and there is no way to verify otherwise. It is unclear how a stack test will be sufficient to demonstrate compliance with the limits set in the permit if there is such variability present at the facility.

The commenter's statement regarding the use of a CEMS to monitor the N_2O emissions are not substantiated. Before the Department assigned a CEMS for the compliance mechanism, the Department contacted the consultant involved with the permit application regarding the use of existing NO_x CEMS. It was presented to the Department that the existing NO_x CEMS has the capability to differentiate between NO_2 and N_2O emissions. Based on this information, the facility will already have a CEMS in place to monitor the NO_x (NO_2) emissions; therefore, this same CEMS can be used to demonstrate compliance with the N_2O limits in the permit. The permit will remain as written.

Comment #49:

The commenter requested the removal of the production based limit for N_2O for SN-08 and SN-09. According to the commenter, SN-08 and SN-09 are not subject to BACT requirements; thus, a limit expressed in terms of lb/unit of production is not necessary. The commenter stated that the mass based limits and associated compliance demonstration requirements included in the permit are sufficient to demonstrate compliance relative to N_2O emissions.

Response to Comment #49:

Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Even though these sources are not subject to BACT requirements, it does not alleviate the facility's responsibility to comply with terms of the permit. Production based limits are not applicable only to PSD sources, and can be found for non-PSD sources. The emission calculations presented to the Department were based on a lb/ton emission factor for these sources. The permit will remain as written.

Comment #50:

The commenter requested the addition of stack testing requirements for N_2O emissions for SN-08 and SN-09. The commenter proposed stack testing to demonstrate compliance with permitted limits in place of continuous monitoring. According to the commenter, the proposed test frequency is consistent with other test requirements in the permit.

Response to Comment #50:

The N_2O stack testing is not necessary as proposed. The facility will operate a NO_x CEMS, which can be used to determine compliance with the N_2O limits found in the permit. See Response to Comment #48.

Comment #51:

The commenter requested a revision to the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

DM Weatherly Nitric Acid Plant #1

SN-13
DMW Nitric Acid Plant #1

Source Description

The DMW Nitric Acid Plant #1 (SN-13) produces weak nitric acid (~~56~~61%-~~65~~67% strength) by oxidizing ammonia in the presence of a platinum catalyst. The major contributor to air emissions from this process is the absorption column tail gas. In the absorption column, nitrogen dioxide is absorbed into condensate with nitric acid exiting the absorption column. The efficiency of this process determines the amount of nitrogen oxides released to the atmosphere in the tail gas. A SCR will be used to control the NO_x emissions from SN-13. This nitric acid plant was originally installed at the American Cyanamid Company facility at Hannibal, Missouri and was relocated to the El Dorado Chemical in 1990. ~~Therefore, t~~This plant is subject to NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants), ~~since~~ because it was constructed or modified after August 17, 1971 and produces weak nitric acid (between 30% and 70-% strength).

The uncontrolled emissions from SN-13 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for NO_x, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limit at this source.

Response to Comment #51:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #52:

The commenter proposed that Specific Condition 12 include the compliance demonstration requirements consistent with changes made in a redline strikethrough version of the draft permit. The commenter stated that this change is consistent with EDCC's proposed deletion of the CEMS monitoring requirement for N_2O.

Response to Comment #52:

The requested changes were not made. The compliance mechanisms in the draft permit are sufficient and do not need to be changed. ADEQ does not agree to the removal of CEMs. Each of the requested changes will be addressed in the appropriate responses below.

Comment #53:

The commenter requested the addition of the compliance demonstration requirement in Specific Condition 13 of the draft permit to reference the ammonia testing. According to the commenter, this test requirement is consistent with similar requirements for the other nitric acid plants in operation at EDCC.

Response to Comment #53:

Ammonia testing for SN-13 has been added to the permit as requested.

Comment #54:

The commenter requested the removal of the hourly production limit for SN-13, and related compliance record keeping requirement in Specific Conditions 15 and 17, respectively, of the draft permit. According to the commenter, short term emission limits (i.e., lb/hr limits) for SN-13 are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #54:

The emission calculations submitted on behalf of the facility indicate that this source has a design production rate of 400 tons per day. The short term maximum capacity was determined by taking the daily capacity of 400 tons per day and dividing by 24 hours per day of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #55:

The commenter requested that the Department add the reference to the CEMS Monitoring Plan required by the global settlement between EPA/DOJ/LSB. The commenter stated that SN-13 is a covered source in the global settlement and must comply with the requirements of the CEMS Monitoring Plan included therein.

Response to Comment #55:

The Department agrees, and has added the necessary reference to the CEMS Plan, and includes the updates to the following table.

Analyzer	Parameter	Location	Span Value
NO_x Stack Analyzers	NO_x, ppm by volume, dry basis[1]	Stack	Normal: 0 – 500 ppm NO_x, or as appropriate to accurately measure the normal concentration range. SSM: 0 to 125% of the maximum estimated NO_x emission concentration
Stack Flow meter	Volumetric Flow rate, SCFH[2]	Stack	0 to 125% of the maximum expected volumetric flow rate

[1]For the purposes of calculations under the CEMS Plan in Appendix J, as-is NO_x concentration measurements at the DM Weatherly Nitric Acid Plant # 1(e.g., those utilizing FTIR, NDIR, or other types of stack gas analyzers capable of making wet measurements) will be assumed to be dry. However, the permittee may adjust for any

moisture contained in the stack gas if the nitric acid plant is equipped with a continuous moisture analyzer or equipment which removes the moisture prior to the stack gas analyzer.
[2]For the purposes of the calculations under the CEMS Plan, as-is volumetric flow rate measurements will be assumed to be dry. However, the permittee may adjust for any moisture contained in the stack gas if the nitric acid plant is equipped with a continuous moisture analyzer.

Comment #56:

The commenter requested the removal of the N_2O CEMS monitoring requirement for SN-13. According to the commenter, there are currently no health based emission standards for GHG pollutants that would warrant the need for continuous monitoring, and there are no underlying federal regulatory requirements for the continuous monitoring of GHG emissions. The commenter stated that the proposed emission limits for N_2O are based on factors developed from annual testing required by the GHG Reporting Rule. The commenter contended that the results for SN-13 have been consistent, with no significant variability, thus indicating that continuous monitoring would serve no useful purpose. In addition, the commenter stated that the installation, operation, and maintenance of a CEMS in this instance places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #56:

See Response to Comment #48 above. The requested change was not made.

Comment #57:

The commenter requested the removal of the production based limit for N_2O for SN-13. According to the commenter, SN-13 is not subject to BACT requirements; thus, a limit expressed in terms of lb/unit of production is not necessary. The commenter contended that the mass based limits and associated compliance demonstration requirements included in the permit are sufficient to demonstrate compliance relative to N_2O emissions.

Response to Comment #57:

See Response to Comment #49 above. The requested change was not made.

Comment #58:

The commenter proposed a stack testing requirement for N_2O emissions from SN-13 as a compliance mechanism. According to the commenter, this change is consistent with EDCC's proposed deletion of the CEMS monitoring requirement for N_2O for this source.

Response to Comment #58:

See Response to Comment #50 above. The requested change was not made.

Comment #59:

The commenter requested the addition of a stack testing requirement to demonstrate compliance with the ammonia emissions from SN-13. The commenter also requested the addition of the stack testing language for the ammonia testing for SN-13. See Comment # 53 above.

Response to Comment #59:

The testing requirement has been added as requested. See Response to Comment #53 above. The following condition was added:

The permittee shall have a third party annually stack test the Ammonia emissions from SN-13 within 180 days of startup of the DM Weatherly Nitric Acid Plant # 1 (SN-13) after installation of the control equipment, and every 12 months thereafter. The stack test shall be performed using method CTM-027 or an equivalent method approved by the Department shall be used for ammonia. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above.

Comment #60:

The commenter requested that the Hexane emissions for SN-48 be updated consistent with the emission calculations submitted to the ADEQ on September 12, 2013.

Response to Comment #60:

The permit has been updated as requested. The annual emissions for Hexane have been updated to 0.16 tpy.

Comment #61:

The commenter requested a revision to the process description related to weak acid strength as indicated below to improve the accuracy of the process related information (as provided by EDCC staff). The commenter also requested that the ADEQ delete the reference to primary abatement technology relative to the control of N_2O emissions. According to the commenter, this change is consistent with the updated BACT Analysis for the DMW2 Plant submitted to the ADEQ on September 3, 2013.

SN-59

DM Weatherly Nitric Acid Plant #-2

Source Description

EDCC proposes to add a second DM Weatherly Nitric Acid Plant as a part of the proposed facility expansion. The DM Weatherly Nitric Acid Plant #2 (DMW2 Plant, or SN-59) will produce weak nitric acid (~~56~~61-~~65~~67% strength) by oxidizing ammonia in the presence of a platinum catalyst. Significant emissions from this process include unreacted nitrogen oxides (NO_x) from the absorption step in the process. Construction of this plant will include installation of a Selective Catalytic Reduction (SCR) unit to control NO_x emissions, which will allow NO_x emissions to be reduced to meet the NSPS Subpart Ga (Standards of Performance for Nitric Acid Plants for which Construction, Reconstruction, or Modification Commenced After October 14, 2011) limit of 0.5 lb/ton of 100% nitric acid produced (30-day rolling average basis, including SSM related emissions). EDCC will utilize ~~primary and~~ tertiary abatement ~~technologies~~ technology to control N_2O emissions from DMW2.

Response to Comment #61:

The permit has been updated as requested.

Comment #62:

The commenter requested an update to the compliance demonstrations for SN-59. The commenter stated that this change is consistent with EDCC's proposed deletion of the CEMS monitoring requirement for N_2O from this source.

Response to Comment #62:

The requested changes were not made. The compliance mechanisms in the draft permit are sufficient and do not need to be changed. ADEQ does not agree to the removal of CEMs. Each of the requested changes will be addressed in the appropriate responses below.

Comment #63:

The commenter requested the NO_x hourly limit for SN-59 be updated consistent with the emission calculations submitted to the ADEQ on September 12, 2013 and vendor information.

Response to Comment #63:

The permit has been updated as requested.

Comment #64:

The commenter requested the NO_x hourly limit found in the BACT Analysis Summary table in Specific Condition 33 of the draft permit be updated consistent with the emission calculations submitted to the ADEQ on September 12, 2013 and vendor information.

Response to Comment #64:

The permit has been updated as requested.

Comment #65:

The commenter requested that the BACT Analysis Summary table in Specific Condition 33 of the draft permit be updated based on the BACT Analysis submitted to the ADEQ on September 6, 2013. The commenter maintained its stated position that significant uncertainty exists relative to the ability of catalytic reduction to achieve a 5 ppmv NO_x limit with an acceptable margin of compliance considering site specific operational/equipment variability factors over the long term. The commenter requested that the ADEQ reconsider its position relative to an adjustable limit/operational study approach that would result in an accurate, statistically based BACT limit and averaging period. The commenter stated that we have already provided the ADEQ with supporting regulatory references in the BACT Analysis for an adjustable limit approach. The commenter further contended that the ADEQ has the authority to pursue such an alternative BACT limit approach in a case where a BACT limit has been included in an issued permit, but has not been demonstrated to a degree that removes compliance related uncertainty, as addressed in the NSR Manual and supported by a 2006 EPA Environmental Appeals Board decision.

Response to Comment #65:

Comment #65 is the same as Comment #16 above. See Response to Comment #16 above.

Comment #66:

The commenter requested that the BACT Analysis Summary table in Specific Condition 33 of the draft permit be updated based on the BACT Analysis submitted to the ADEQ on September 3, 2013. The commenter maintained its stated position that significant uncertainty exists relative to the ability of catalytic reduction to achieve a 30 ppmv N_2O limit with an acceptable margin of compliance considering site specific operational/equipment variability factors over the long term. The commenter requested that the ADEQ reconsider its position relative to an adjustable limit/operational study approach that would result in an accurate, statistically based BACT limit.

Response to Comment #66:

Comment #66 is the same as Comment #18 above. See Response to Comment #18 above.

Comment #67:

The commenter requested the removal of the hourly production limit for SN-59, and related compliance record keeping requirement in Specific Conditions 35 and 37, respectively, of the draft permit. The commenter stated that the short term emission limits (i.e., lb/hr limits) for SN-59 are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #67:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity of 461,725 ton/yr and dividing by 8,760 hours per year of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #68:

The commenter requested the addition of a stack testing requirement for N_2O emissions for SN-59. The commenter proposed stack testing to demonstrate compliance with permitted limits in place of continuous monitoring. The commenter stated that the proposed test frequency is consistent with other test requirements in the permit.

Response to Comment #68:

See Response to Comment #50 above. The requested change was not made.

Comment #69:

The commenter requested revisions to the ammonia testing requirements for SN-59. The commenter stated, "[t]o support the adjustable BACT limit/study approach for NOx emissions, a similar adjustable limit approach, to be effective during the study, is needed to ensure compliance with the ammonia limits as the catalytic abatement system is fine tuned to the lowest level possible. During this adjustment period, intermittent slippage of ammonia could be above the 10 ppm level."

Response to Comment #69:

Comment #69 is equivalent to Comment #16 above. The commenter is requesting an "adjustable" BACT limit. See Response to Comment #16 above. The requested change was not made.

Comment #70:

The commenter requested the removal of the CEMS requirement for N_2O emissions from SN-59. The commenter also requested the removal of the production based limit for N_2O emissions from this source. The commenter stated that there are currently no health based emission standards for GHG pollutants that would warrant the need for continuous monitoring, and there are no underlying federal regulatory requirements for the continuous monitoring of GHG emissions. The commenter stated that the proposed emission limits for N_2O are based on the maximum capacity of the equipment and vendor specifications. The commenter stated that the installation, operation, and maintenance of a CEMS in this instance places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #70:

See Response to Comment #48 and Response to Comment #49 above. The requested changes were not made.

Comment #71:

The commenter requested revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-60
DM Weatherly Nitric Acid Plant #~~-~~2 Cooling Tower

Source Description

The DM Weatherly Nitric Acid Plant #~~-~~2 Cooling Tower (SN-60) provides non-contact cooling water to the process equipment in the DM Weatherly Nitric Acid Plant #2 (SN-59), ~~and~~ the East and West Nitric Acid Plants (SN-08 and SN-09), the NACSAC® Plant (SN-47), and the ammonia shipping and storage refrigeration system. Particulate matter is emitted during operation of the cooling tower.

Response to Comment #71:

The permit has been updated as requested.

Comment #72:

The commenter requested revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-47
Nitric Acid Concentration Plant (NACSAC® Plant)

Source Description

The PLINKE designed NACSAC® Plant (SN-47) concentrates weak nitric acid (~~56~~61% - ~~65~~67% strength) to strong nitric acid (greater than 98% strength) by extracting water from the weak nitric acid with sulfuric acid, which is then dehydrated and recycled to the front end of the process.

Response to Comment #72:

The permit has been updated as requested.

Comment #73:

The commenter requested the removal of the hourly production limit for SN-47, and related compliance record keeping requirement in Specific Conditions 77 and 79, respectively, of the draft permit. The commenter stated that the short term emission limits (i.e., lb/hr limits) for SN-59 are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #73:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity of 45,625 ton/yr and dividing by 8,760 hours per year of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #74:

The commenter requested revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-10
Nitric Acid Vent Collection System

Source Description

In October of 1997, a packed tower hydrogen peroxide scrubber was installed to control nitrogen oxide emissions. The top portion of the packed tower treats nitrogen oxide emissions from the weak nitric acid storage vents (Tanks 49, 50, and 51, as well as three (3) new tanks being added with the facility expansion). The bottom section of the packed tower treats the nitrogen oxide emissions present in the blend acid tanks (Tanks 43, 44, 45, and 46) bleaching air stream. The nitric acid loading system vents (formerly SN-29) are also collected and routed to the packed tower. The overheads from the packed tower are routed through a Venturi Scrubber for additional treatment before being vented to the atmosphere through a stack designated as SN-10. The strong nitric acid storage tank vents (Tanks 47, 48, 66, 67, 68, 69, 70 and 71) are routed directly to the Venturi Scrubber (i.e., bypass the packed tower). Overall nitrogen oxide and visible emissions are reduced due to these pollution control devices.

With the issuance of Air Permit 0573-AOP-R8, the Car Barn Scrubber (previously permitted as SN-37) was removed as a source. The nitric acid fumes resulting from the cleaning and pressure checking of rail cars (conducted in the Car Barn) are now routed to SN-10 for control.

The uncontrolled emissions from SN-10 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for NO_x, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limit at this source.

Response to Comment #74:

The permit has been updated as requested, except for adding the word "formerly" in front of SN-29. The Department understands that the facility claims that these emissions are captured and routed to the Nitric Acid Vent Collection System (SN-10); however SN-29 is the source of these emissions and will remain as written in the draft permit.

Comment #75:

The commenter requested that the Department add the annual limit and record keeping requirement for nitric acid loading (SN-29) to proposed specific conditions. The commenter requested the ADEQ to delete SN-29 from the permit.

Response to Comment #75:

The Department understands that the facility claims that these emissions are captured and routed to the Nitric Acid Vent Collection System (SN-10); however SN-29 is the source of these emissions and will remain as written in the draft permit.

Comment #76:

The commenter requested that the H_2SO_4 emissions from SN-07 be updated to 2.83 lb/hr based on the emission calculations submitted to the ADEQ on September 12, 2013.

Response to Comment #76:

The permit has been updated as requested.

Comment #77:

The commenter requested the addition of the record keeping requirement for SN-07 as indicated below. The commenter stated that this requirement is consistent with other record keeping requirements in the permit.

The permittee shall not manufacture in excess of 200,750 tons of 100% sulfuric acid per rolling 12-month total through the sulfuric acid plant. The permittee shall keep records of the amount of sulfuric acid produced at the facility. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. ~~These records shall be kept on site, and shall be made available to Department personnel upon request.~~ This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; and 40 CFR 70.6]

Response to Comment #77:

The permit has been updated as requested.

Comment #78:

The commenter requested the deletion of the daily production limit and related compliance record keeping requirement for SN- 07. The commenter stated that short term emission limits (i.e., lb/hr limits) for SN-07 are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #78:

The emission calculations submitted on behalf of the facility indicate that this source has a design production rate of 550 tons per day. The short term maximum capacity was determined by taking the daily capacity of 550 tons per day and dividing by 24 hours per day of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #79:

The commenter requested a revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff). The commenter also noted that the Pease Anthony Scrubber is being removed as part of the new Brinks Scrubber installation at SN-05.

E2 Ammonium Nitrate Plant

SN-05, SN-17, and SN-41
Scrubbers

Source Description

The Ammonium Nitrate E2 Plant Brinks Scrubber (SN-05) controls emissions from ~~the air stream from the shroud of the E2 Ammonium Nitrate Prill Tower Fans (SN-06)~~<u>the E2 prill towers and cooling trains</u>, the intermediate ammonium nitrate storage tanks, and the E2 Plant Chemical Condensate Tank. The E2 Plant Brinks Scrubber (SN-05) is actually two scrubbers, one for each prill tower. EDCC has the ability to shut down one scrubber *and the associated prill tower. When one scrubber is shut down, EDCC will not operate the associated prill tower while the scrubber is not operating.*

~~*The prills are cooled and screened when they exit the prill tower. The air from the cooling process is vented to the Pease-Anthony (Venturi) Scrubber (SN-17). With the issuance of permit 0573-AOP-R7, emissions from the Pease-Anthony Scrubber (SN-17) on the E2 HDAN Plant Cooling Train were routed to SN-05 for additional control.*~~

The E2 Plant Chemical Steam Scrubber (SN-41) controls particulate matter and ammonia emissions from the three E2 Plant Neutralizers (formerly SN-02 and SN-03, and a third neutralizer added in 2002), the Ammonium Nitrate Low Concentrator (formerly SN-04), and the E2 Auxiliary Ammonium Nitrate Concentrator (formerly SN-20).

The uncontrolled emissions from SN-05 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for PM_{10}, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limit at this source.

Response to Comment #79:

The permit has been updated as requested.

Comment #80:

The commenter requested that the emission description for the emissions from SN-06 and SN-17 that are routed to SN-05 be updated to:

> Exhausts from Prill Towers and Cooling Trains are routed to SN-05.

Response to Comment #80:

The permit has been updated as requested.

Comment #81:

The commenter requested that the ammonia testing specified in Specific Condition 106 of the draft permit be updated. The commenter stated that with the removal of the Pease Anthony Scrubber (part of the new Brinks Scrubber installation at SN-05) and as a result of the installation of the new Brinks Scrubber at SN-05, ammonia testing can be performed at the control equipment exhaust.

The permittee shall have a third party test once every 60 months the NH_3 emissions from ~~SN-17's exhaust prior to the inlet of~~ SN-05 using an approved method. ~~SN-17 was last tested on September 21, 2012. The NH_3 emissions from SN-17 shall be less than 5.0 lb/hr.~~ If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months . The units shall be operated at least at 90% of rated capacity when the stack test is completed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-~~17~~05, 90% rated capacity is defined as:

a. The 90% of the rated capacity of the prill towers will be on an ammonium nitrate production basis.
b. The product exit temperature at the prill towers at the time of test must be less than 275°F.

[Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Response to Comment #81:

The permit has been updated with the following condition:

The permittee shall have a third party annually stack test the NH_3 emissions from SN-05 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using Test method CTM-027 or an equivalent method approved by the Department shall be used for Ammonia. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-05, 90% rated capacity is defined as:

a. The 90% of the rated capacity of the prill towers will be on an ammonium nitrate production basis.
b. The product exit temperature at the prill towers at the time of test must be less than 275°F.

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

Comment #82:

The commenter requested the removal of the hourly production limit for SN-05, and related compliance record keeping requirement in the draft permit. The commenter stated that the short term emission limits (i.e., lb/hr limits) for sources at the E2 Ammonium Nitrate Plant are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #82:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity of 525,600 ton/yr and dividing by 8,760 hours per year of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #83:

The commenter requested a revision of the control equipment requirements as indicated below. The commenter stated that the Pease Anthony Scrubber would be removed as part of the new Brinks Scrubber installation at SN-05.

The E2 Plant Brinks Scrubber (SN-05) and the E2 Plant Chemical Steam Scrubber (SN-41) shall be kept in good working condition at all times. SN-05 shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-05 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parametric exceedance, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be made available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable.

SN	Description	Parameter	Units	Operation Limits
05	E2 Plant Brinks Scrubber	Scrubber Liquid Flow Rate for Each Scrubber	gal/min	225 (minimum)
		Gas Pressure Drop Across Unit for Each Scrubber	in. H_2O	2.5 (minimum)
		pH	-	0.5 - 6.0

[Regulation 18, §18.1004 and A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311]

Response to Comment #83:

The permit has been updated as requested.

Comment #84:

The commenter requested the source title and description for SN-28 be updated. The commenter stated that the E2 Plant no longer manufactures LDAN.

SN-28
E2 Plant HDAN~~/LDAN~~ Loading

Source Description

~~E2 Plant~~ HDAN~~/LDAN~~ produced at the E2 Plant is loaded in-to rail cars or trucks. Particulate matter emissions occur as the HDAN~~/LDAN~~ is being loaded into the rail cars or trucks.

Response to Comment #84:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #85:

The commenter requested a revision of the source description as indicated below. The commenter stated that the changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013 and process information received from EDCC staff.

SN-34
E2 Plant Solution Reactor

Source Description

A 35% nitric acid/magnesium oxide solution is created by reacting 56% nitric acid with magnesium oxide through agitation. Approximately 0.5% of the magnesium oxide is contained in the final ammonium nitrate product. Each batch takes two ~~and a half~~ hours to make ~~6.77~~2.905 tons of nitric acid/magnesium oxide solution. This solution reactor, which does not contain any pollution control equipment, has the capability of producing ~~eight~~ twelve batches of E2 solution a day while the E2 Ammonium Nitrate Plant is running at its maximum rate. The solution leaves the reactor, where it is filtered to remove any excess magnesium oxide and other trace particulates, and is stored in a heated tank as 35% solution. The solution is pumped ~~from the tank to the top of the E2 Prill Tower (SN-06), where it is mixed with 95% ammonium nitrate solution prior to the High~~to the inlet of the Low Concentrator.

Response to Comment #85:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #86:

The commenter requested a revision of the source description as indicated below. The commenter stated that the proposed change is consistent with the installation of the new Brinks Scrubber at SN-14.

KT Ammonium Nitrate Plant

SN-14
LDAN Prill Tower

Source Description

To be sold in final product form, LDAN at the KT Plant is prilled in a prilling tower. A 97% ammonium nitrate solution is mixed with a proprietary additive in a head tank. The prilling operation is accomplished by dispersing the ammonium nitrate solution downward in the tower through a spray nozzle. Long residence times and low air rates contribute to the production of high quality prills, which generate lower particle fines and therefore, lower particulate matter emissions. Four fans control the temperature of the prills leaving the bottom of the prilling tower. This air cools and solidifies the ammonium nitrate droplets into solid prills. The air stream and entrained particles are vented to ~~the atmosphere through chimneys on top of the tower~~a Brinks scrubber (SN-14).

Response to Comment #86:

The permit has been updated as requested.

Comment #87:

The commenter requested that the hourly production limit and related compliance record keeping requirement for SN-14 be deleted. The commenter stated that the short term emission limits (i.e., lb/hr limits) for sources at the KT Ammonium Nitrate Plant are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #87:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity of 394,200 ton/yr and dividing by 8,760 hours per year of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #88:

The commenter requested the deletion of the unit/ton of production based reference for the particulate matter emission testing for SN-14. The commenter stated that this change is necessary, as the emission factor is correlated to air flow. The commenter stated that the air flow fluctuates based on the temperature at the bottom of the prill tower, not production rate. The commenter stated that there is no correlation between emissions and the production rate.

Response to Comment #88:

The lb/ton of prill produced has been removed, and the maximum exhaust flow rate has been added as a requirement for testing and for CAM recordkeeping requirements. The inclusion of the maximum exhaust flow rate has also been applied to all other sources with Brinks Scrubbers and associated CAM recordkeeping requirements. The condition has been updated to the following:

The permittee shall have a third party stack test the PM, PM_{10}, and the $PM_{2.5}$ emissions from SN-14 within 180 days after installation of the new Brinks Scrubber, and every 12 months thereafter. The permittee shall not exceed 0.085 mg/acf of particulate matter emissions from SN-14. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The stack test shall be performed using EPA Reference Method 201A or 5, EPA Reference Method 202, and a method approved in advance by the Department. The permittee shall maintain the approved method with the permit. By using Method 5 for PM_{10}, the facility will assume all collected particulate is PM_{10}. PM_{10} emission rates measured during this testing shall be less than the permitted emission rates specified in Specific Condition 127. This unit shall be operated at 90% or more of maximum capacity when the stack test is performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. 90% of maximum capacity is defined as:

a. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
b. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
c. The moisture content of the product exiting the dryer must be less than 0.1%.
d. 90% of the maximum exhaust flow rate (Maximum exhaust flow rate as provided by the facility = 100,000 acfm)

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

Comment #89:

The commenter requested that all references to the KT plant brinks scrubber be updated to KT Plant Brinks Scrubber.

Response to Comment #89:

The permit has been updated as requested.

Comment #90:

The commenter requested that the source title and description be updated. The commenter stated that the proposed changes apply across the permit relative to the cooler deletion which is based on process related information received from EDCC staff. The commenter stated that the changes related to SN-15 reflect the installation of the new Brinks Scrubber.

SN-15, SN-18, and SN-21
KT Plant Dryer/~~Cooler~~, Baghouse, and Scrubber

Source Description

Prills exiting the bottom of the KT LDAN Prill Tower (SN-14) are conveyed to a predryer and dryer. The predryer and dryer exhaust air streams are drawn by a common fan concurrent to the direction of the prill and blown to a ~~wet~~ Brinks scrubber. The scrubber efficiency is increased by injecting a portion of the scrubbing solution into the fan system. The ~~wet~~ KT Plant Dryer ~~Brinks scrubber~~ exhaust, which contains ammonia and particulate matter, is vented directly to the atmosphere through a stack designated as SN-15.

An external coating of high melting point organic material and talc is added to the LDAN to improve the storage and flow of the final product. The talc is stored in an enclosed silo that pneumatically feeds into a bulk talc hopper. Both the silo and the hopper are equipped with a baghouse (SN-18) to minimize particulate matter emissions. The silo baghouse only operates when the talc is being blown into the silo during the unloading of talc when delivered to the plant. The baghouse at the hopper operates when talc is being added to the LDAN. The baghouses do not operate at the same time.

During LDAN production at the KT Plant, ammonium nitrate solution exits a neutralizer and is pumped into a 50 ton solution storage tank. The ammonium nitrate solution (composed of ~~95~~90% ammonium nitrate and ~~5~~10% water) is in molten form at this stage in the process. In the storage tank, the ammonium nitrate solution is blended with "recycled" ammonium nitrate solution, which has been concentrated in the auxiliary concentrator. The ammonium nitrate must be concentrated to 97.5% prior to prilling operations. For this to occur, the ammonium nitrate solution is transferred from the 50 ton tank to a dehydrator. The dehydrator air is blown through the solution to remove excess water. The exhaust stream from the dehydrator is directed to the Brinks Scrubber (SN-21) prior to being vented to the atmosphere.

The uncontrolled emissions from SN-15, SN-18, and SN-21 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because it meets the following criteria: (1) the units are subject to emission limitations for PM_{10}, (2) the sources are equipped with a control device, and (3) the units have potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for these sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limits at these sources.

Response to Comment #90:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #91:

The commenter requested the deletion of the maximum dehydrator input rate from SN-21. The commenter stated that based on information received from EDCC staff, the other parameters are sufficient to confirm during testing that 90% of the maximum production rate is being achieved.

Response to Comment #91:

The permit has been updated as requested. The maximum exhaust flow rate has been added.

Comment #92:

The commenter requested that all references to the KT brinks scrubber be updated to KT Brinks Scrubber, and requested the deletion of the word cooler from the KT Plant Dryer/Cooler Scrubber (SN-15). The commenter stated that these changes are necessary to maintain consistency relative to source identification. The commenter also requested revision to the monitoring parameters and associated values for SN-15 as indicated below. The commenter stated that a Brinks scrubber will be installed at SN-15, and parametric monitoring there should be consistent with the other Brinks scrubber installations.

SN	Description	Parameter	Units	Operation Limits
15	KT Plant Dryer/~~Cooler~~ Scrubber	Scrubber Liquid Flow Rate ~~Scrubber Liquor pH~~	gal/min -	225 (minimum)~~0.5 – 4.5~~
		Gas Pressure Drop Across Unit ~~Liquid Flow Rate (combination of fan and ductwork)~~	in. H_2O~~gal/min~~	2.5 (minimum)~~80 (minimum)~~
		pH~~Amperage~~	-~~amps~~	0.5 - 6.0~~290 (minimum)~~
18	KT Plant Baghouse	Gas Pressure Drop	in. H_2O	0.5 - 8.0
21	KT Brinks Scrubber	Scrubber Liquid Flow Rate~~Liquid Gas Pressure to Top Spray Nozzles~~	gal/min ~~psig~~	225 (minimum)~~80 – 100~~
		Gas Pressure Drop Across Unit	in. H_2O	2.5 (minimum)
		pH	-	0.5 – ~~4.5~~6.0

Response to Comment #92:

The permit has been updated as requested. The maximum exhaust flow rate for SN-15 and SN-21 has been added as a requirement for CAM recordkeeping requirements.

Comment #93:

The commenter requested the removal of the hourly production limits and related compliance record keeping requirement for the KT Ammonium Nitrate Plant. The commenter stated that the short term emission limits (i.e., lb/hr limits) for sources at the KT Ammonium Nitrate Plant are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #93:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity of 547,500 ton/yr and dividing by 8,760 hours per year of operation. This short term number doesn't represent a realistic short term maximum capacity for these sources as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for these sources.

Comment #94:

The commenter requested the removal of Specific Condition 159 as a compliance mechanism for Specific Condition 154 (i.e. the Primary Reformer SN-49). The commenter also requested the removal of Specific Condition 159 (hourly production limit) as a compliance mechanism for Specific Conditions 155 and 156. The commenter stated that these changes are necessary, as the basis for the proposed emission limits in terms of fuel gas/heat input to the primary reformer, not production.

Response to Comment #94:

The Department agrees with the removal of the hourly production limit as a compliance mechanism. The hourly production limit has been removed from Specific Condition 159, and replaced with an annual natural gas throughput limit as the emissions are based on the fuel usage.

Comment #95:

The commenter requested a change in the compliance demonstration for NO_x, N_2O, and CO_2e emissions. The commenter stated that these changes are consistent with the proposed deletion of the CEMS monitoring requirement for CO_2 and N_2O. The commenter proposed stack testing for these pollutants in lieu of continuous monitoring. The commenter requested a revision to the NO_x BACT limit for SN-49 to require that compliance with the lb/MMBtu and lb/hr BACT limits be demonstrated on a 30-day rolling average basis. The commenter stated that this change was necessary due to the ADEQ's decision to require a NO_x CEMS to demonstrate compliance rather than stack testing. The commenter's understanding, after discussion with the ADEQ, was that the NO_x CEMS was required in order to be consistent with the PSD permitting requirements for the Iowa facility (i.e., currently, the only ammonia plant regulated by a PSD permit). The commenter stated that in that case, the 30-day average was consistent with the averaging period for the Iowa BACT limit for NO_x, with the same consideration that the variability in plant operations and associated emissions supported the need for an averaging period longer than 3 hours. The commenter also requested a revision of the N_2O limit as indicated in the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

Response to Comment #95:

The commenter is not correct that the Department added the NO_x CEMS to be consistent with the Iowa facility. The Department reviewed numerous possible compliance mechanisms. The commenter cannot propose a new BACT limit for this source during the comment period. The facility proposed the 3-hour average for this source, and the Department agreed with the facility that this averaging time was appropriate. The use of a NO_x CEMS, which can also be used as to determine compliance with the N_2O emissions, is a much more efficient way for the facility to demonstrate compliance with the NO_x and N_2O emissions from the facility than stack testing. The CO_2 CEMS has been removed as requested. The compliance mechanism for the CO2 emissions from SN-49 has been updated to include periodic stack testing.

Comment #96:

The commenter requested deletion of the hourly production limit and related compliance record keeping requirement as indicated below. The commenter stated that short term emission limits (i.e., lb/hr limits) for sources at the Ammonia Plant are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates places an unnecessary burden on EDCC relative to cost and manpower.

159. *~~The permittee shall not manufacture in excess of 58.3 tons per hour of ammonia through the Ammonia Plant Primary Reformer (SN-49). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]~~*

161. *The permittee shall keep records of the production manufactured in the Ammonia Plant Primary Reformer (SN-49) as specified in Specific Conditions ~~159 and~~ 160. These records shall identify ~~any hour during which acid in excess of the quantities specified in Specific Condition 159 was produced, and shall~~ contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall*

be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

Response to Comment #96:

The Department agrees with the removal of the hourly production limit. An annual natural gas throughput limit has been added to the permit as the emissions are based on the fuel usage.

Comment #97:

The commenter requested the deletion of the CO emission testing for SN-49 as found in Specific Condition 164 of the draft permit. The commenter proposed that the stack testing frequency for CO be set consistent with that for the other criteria pollutants.

164. The permittee shall have a third party stack test the SO_2, CO, and VOC emissions from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack tests shall be performed using EPA Reference Method~~s~~ 6C for SO_2, EPA Reference Method 10 for CO, and EPA Reference Method 25A for VOC. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

165. ~~The permittee shall have a third party annually stack test the CO emissions from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using EPA Reference Method 10 for CO. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]~~

Response to Comment #97:

The Title V program requires all part 70 permits to contain sufficient testing, monitoring reporting, and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. This requirement is also integrated into Regulation 26. The commenter has requested to remove the continual testing requirement to ensure the facility's compliance with the CO emission limits. A single test by no means is sufficient to assure continual compliance with the emission limits found in the permit. Therefore, in response to the commenter's request for consistency, the permit will be updated to include additional testing requirements, similar to the CO testing requirements found in the draft permit, for Particulate Matter emissions, SO_2 emissions, and VOC emissions.

Comment #98:

The commenter requested a revision of the stack testing requirements as indicated below. According to the commenter, the addition of testing requirements for N_2O and CO_2 is consistent with EDCC's proposed deletion of the CEMS monitoring requirements for these pollutants.

The permittee shall have a third party stack test the Methane (CH_4), Nitrous Oxide (N_2O), and Carbon Dioxide (CO_2) emissions from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack tests shall be performed using EPA Reference Method 18 for Methane, EPA Method 320, ASTM D6348-03, or an equivalent method approved by the Department for N_2O, and EPA Method 3A for CO_2. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Response to Comment #98:

The CO_2 testing will be added as requested. The N_2O testing will not be added. See Response to Comment #48 and Response to Comment #50 above. Additional stack testing requirements for Methane and CO_2 were added. See Response to Comment #97 above.

Comment #99:

The commenter requested a revision of the NO_x limit for SN-49 to include a 30-day rolling average. According to the commenter, the requested change is consistent with Comment #95 above. The commenter also requested the deletion of the CEMS monitoring requirements for N_2O and CO_2 for this source. The commenter stated that there are currently no health based emission standards for GHG pollutants that would warrant the need for continuous monitoring, and there are no underlying federal regulatory requirements for the continuous monitoring of GHG emissions. The commenter stated that the proposed emission limits for N_2O and CO_2 are based on the maximum capacity of the equipment and vendor specifications. The commenter stated that the installation, operation, and maintenance of multiple CEMS units in this instance placed an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #99:

The CO_2 CEMS has been removed. The N_2O CEMS requirement will not be removed. See Response to Comment #48 and Response to Comment #95 above.

Comment #100:

The commenter requested a revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-50
Ammonia Plant Condensate Steam Stripper

Source Description

Carbon monoxide is formed as a byproduct in the catalytic steam reforming process. After cooling, the carbon monoxide and water contained in the synthesis gas are converted to carbon dioxide and hydrogen in the High Temperature and Low Temperature Shift Converters. Unreacted steam is condensed and separated from the synthesis gas in a knockout drum, and the condensate is flashed in the Condensate Steam Stripper (SN-50) to remove volatile gases. The residual condensate may be ~~is~~ returned to the boiler or reused in another portion of the process. ~~may be temporarily held in the de-aerator until ready for use as feed water to the boiler.~~

Response to Comment #100:

The source description has been updated as requested.

Comment #101:

The commenter requested revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-51
Ammonia Plant CO_2 Regenerator

Source Description

After the carbon monoxide shift, the carbon dioxide is removed from the process gas by sending the synthesis gas through an absorption tower where a methyl diethanolamine/piperazine solution (MDEA) is used to strip the carbon dioxide out of the gas. Carbon dioxide is removed from the MDEA in a stripper column (CO_2 Regenerator), where it is vented to the atmosphere (SN-51).

Response to Comment #101:

The source description has been updated as requested.

Comment #102:

The commenter requested a revision of the emission limits as indicated below. The commenter stated that these changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

SN	*Description*	*Pollutant*	*lb/hr*	*tpy*
51	*Ammonia Plant CO_2 Regenerator*	*VOC*	*33.7*	*147.4*
		CO	~~*7.4*~~ *1.5*	~~*32.1*~~ *6.5*
		CO_2e	~~*147,000*~~*146,262.6*	~~*643,860*~~*640,669.2*

Response to Comment #102:

The CO and CO_2e emissions have been updated consistent with Response to Comment #24 above.

Comment #103:

The commenter requested a revision of the emission limits as indicated below. The commenter stated that these changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
SN-51	*Ammonia Plant CO_2 Regenerator*	*VOC*	*Good and efficient operating practices*	*0.106 lb/ton of NH_3 produced (3-hr average)* *33.64 lb/hr (3-hr average)* *147.35 tons per rolling 12 months*
		CO		*0.02 lb/ton of NH_3 produced (3-hr average)* *7.31 1.46 lb/hr (3-hr average)* *32.03 6.41 tons per rolling 12 months*
		GHG		*CO_2 2,507.5 lb/ton of NH_3 produced (3-hr average)* *146,262.53 lb/hr CO_2 (3-hr average)* *~~CO_2~~/CO_2e 640,669.20 tons per rolling 12 months~~CO_2 1.26 lb/ton of NH_3 produced (3-hr average)~~* *~~147,000 lb/hr CO_2~~* *CO_2e ~~643,860 tons per rolling 12 months~~*

Response to Comment #103:

The CO and CO_2e emissions have been updated consistent with Response to Comment #24 above.

Comment #104:

The commenter requested the addition of CO_2 stack testing requirements for SN-51 consistent with other testing requirements found throughout the permit, and consistent with EDCC's proposed deletion of the CEMS monitoring requirements for this pollutant.

Response to Comment #104:

The commenter has repeatedly stated that there will be process inconsistency due to operational/equipment variability. It is unclear how a stack test will be sufficient to demonstrate compliance with the limits set in the permit if there is such variability present at the facility. The CEMS requirements found in the draft permit will remain as the compliance mechanism for this source.

Comment #105:

The commenter requested the deletion of the CEMS monitoring requirement for CO_2 emissions at SN-51. According to the commenter, there are currently no health based emission standards for GHG pollutants that would warrant the need for continuous monitoring, and there are no underlying federal regulatory requirements for the continuous monitoring of GHG emissions. The commenter stated that the proposed emission limits for N_2O are based on the maximum capacity of the equipment and vendor specifications. The commenter stated that the installation, operation, and maintenance of a CEMS in this instance placed an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #105:

The permit will not be updated as requested. See Response to Comment #48 above. The commenter references N_2O emissions from SN-51; however, there were no N_2O emissions proposed by the facility for this source. The commenter has repeatedly stated that there will be process inconsistency due to operational/equipment variability. It is unclear how a stack test will be sufficient to demonstrate compliance with the limits set in the permit if there is such variability present at the facility. The CEMS requirements found in the draft permit will remain as the compliance mechanism for this source.

Comment #106:

The commenter requested that the source description for SN-53, SN-56, and SN-57 be revised to improve the accuracy of the process related information (as provided by EDCC staff). According to the commenter, the automatic ignition system is not part of the revised design of these flares. The commenter also stated that ammonia loading to railcars/trucks is not controlled by these flares. According to the commenter, Ammonia loading is accounted for in SN-58.

Response to Comment #106:

The permit has been updated as requested.

Comment #107:

The commenter requested the CO_2e limits found in Specific Condition 188 of the draft permit be updated to 7,304.2 lb/hr and 719.9 tpy. The commenter stated that these requested changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

Response to Comment #107:

The permit has been updated as requested.

Comment #108:

The commenter requested updates to the BACT Analysis Summary found in Specific Conditions 190, 191, and 192 of the draft permit. For each condition, the commenter requested an update to the CO limit from 0.08 lb/MMBtu to 0.082 lb/MMBtu. For each condition, the commenter requested an update to the N_2O limit from 0.0002 lb/MMBtu to 0.00022 lb/MMBtu. For SN-53, the commenter requested an update to the annual NO_x limit to 6.9 tpy and the commenter requested an update to the CO_2e to 719.9. For SN-56, the commenter requested an update to the hourly CO limit to 156.10 lb/hr. The commenter requested an update to the GHG limits for SN-56 to 117 lb/MMBtu for CO_2, to 0.0022 lb/MMBtu for CH_4, to 0.00022 lb/MMBtu for N_2O, and to 5,179.8 tpy for CO_2e. For SN-57, the commenter requested an update to the hourly CO limit to 0.017 lb/hr. The commenter stated that these requested changes were consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

Response to Comment #108:

The permit has been updated as requested.

Comment #109:

The commenter requested that the gas flow rate limits found in Specific Conditions 195 and 196 of the draft permit be updated based on the updated emission calculations submitted on September 12, 2013. The requested gas throughputs are 2.23 million standard cubic feet through each of the flares SN-53 and SN-56.

Response to Comment #109:

After additional correspondence with the commenter, it was discovered that the 2.23 million standard cubic feet was incorrect. The proper gas throughputs for these sources are 9.0

MMscf/yr and 8.2 MMscf/yr for SN-53 and SN-56, respectively. The permit has been updated to include the proper gas throughputs for the flares.

Comment #110:

The commenter requested revisions to the monitoring requirements for SN-53 and SN-56 as indicated below. According to the commenter, short term flare emissions are based on the maximum capacity of the equipment, and annual emissions have been established based on a limited number of hours at each venting scenario (i.e., normal, SSM, and emergency). According to the commenter, EDCC prefers to monitor hours of operation rather than monitoring gas flow to the flares during the process venting scenarios (i.e., during SSM and emergency events). The commenter stated that this revised monitoring method is sufficient to demonstrate compliance and will eliminate the installation, operation, and maintenance of a continuous monitoring device, which places an unnecessary burden on EDCC relative to cost and manpower.

The permittee shall not operate the Ammonia Plant Ammonia Vent Flare (SN-53) in excess of three (3) hours during any consecutive 24-hour period. For SSM related flare operations at SN-53, the flare shall not be operated in excess of 50 hours during any consecutive 12-month period. For emergency related flare operations at SN-53, the flare shall not be operated in excess of 10 hours during any consecutive 12-month period. For SSM related flare operations, the permittee shall not operate the Ammonia Plant Process SSM Flare (SN-56) in excess of 500 hours during any consecutive 12-month period. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

Response to Comment #110:

The commenter did not provide any evidence supporting the claim that monitoring hours of operation is sufficient to demonstrate compliance with the emission limits of the flares. The commenter did not provide any evidence that the installation, operation, and maintenance of a continuous monitoring device will place an unnecessary burden on EDCC relative to cost and manpower. The permit will not be updated as requested. The permit already contains sufficient compliance mechanisms to demonstrate compliance with the terms and conditions of the permit.

Comment #111:

The commenter requested a revision of the flare operational requirement as indicated below. According to the commenter, EDCC cannot shut down the piping to the flares during an emergency vent if the pilot flame is not present. The commenter stated that pressure relief vents are routed to the flare, which must be allowed to open for safety purposes to prevent over pressure situations. The commenter stated that these type vents must be allowed to function whether the pilot flame is present or not. The commenter stated that it is unlikely that this situation would occur considering the pilot flame monitoring requirements.

The Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57) must have a flame present at all times of operation~~ or if no flame is present, the orifice of the unlit flare must be closed and the piping to the unlit flare shutdown to prevent passive venting of uncontrolled gases~~. The presence of a flare pilot light shall be monitored continuously using a thermocouple, an ultraviolet sensor or any other equivalent device to detect the presence of a flame. ~~In the event of a flame failure, the piping system directed to the flare must automatically shut down to prevent passive venting of ammonia gas.~~ [Regulation 19, §19.303, §19.304, §60.18(b) through (f), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Response to Comment #111:

Due to safety reasons, the permit has been updated as requested. The permit has been updated to the following:

The Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57) must have a flame present at all times of operation. The presence of a flare pilot light shall be monitored continuously using a thermocouple, an ultraviolet sensor or any other equivalent device to detect the presence of a flame.

Comment #112:

The commenter requested a revision of the monitoring requirements for the flares as indicated below. According to the commenter, properly maintaining the flares and associated monitoring devices is already addressed by Plantwide Condition 5; a condition to provide additional/specific record keeping procedures for the flares is unnecessary.

The permittee shall install and operate alarm system <u>at the Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57)</u> to notify the operator of the presence of a pilot flame or other possible flare malfunction. The permittee shall perform monthly visual confirmation of the pilot lights, semi-annually remove the strainer and check for debris, and annual test fire to ensure pilot light. ~~The permittee shall maintain logs of all flare inspection and maintenance activities. These logs shall be kept on site, in accordance with General Provision 7, and made available to Department personnel upon request.~~ [Regulation 19, §19.702; 40 CFR 52, Subpart E; and 40 CFR Part 64]

Response to Comment #112:

Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. Therefore, this condition will remain as written in the draft permit. The commenter is correct that the permittee shall properly maintain the flares as required by Plantwide Condition 5; however, the commenter failed to provide a sufficient compliance mechanism to ensure the proper maintenance of the flares. The permit will be updated to include the appropriate name for each of the flares.

Comment #113:

The commenter requested a revision of the BACT limits as indicated below. The commenter stated that the proposed changes are consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013. The commenter also proposed the deletion of the concentration limits for VOC and CO, because the mass based limits are sufficient for BACT compliance demonstration purposes. The commenter stated that the mass based BACT limits for VOC and CO are also consistent with the unit basis for the SO_2 and NO_x limits.

BACT Analysis Summary				
Source	*Description*	*Pollutant*	*Control Technology*	*BACT Limit*
54	*Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)*	*Opacity*	*Combustion of Natural gas and Good Combustion Practice*	*0%*
		SO_2		*0.00074 lb/MMBtu (3-hr average)* *0.03 lb/hr (3-hr average)* *0.007 tons per rolling 12 months*
		VOC		*0.002 lb/MMBtu (3-hr average)* ~~*4.33 ppm$_{vd}$ @ 3% O_2*~~ ~~*0.19*~~*0.08 lb/hr (3-hr average)* ~~*0.048*~~*0.019 tons per rolling 12 months*
		CO		*0.01 lb/MMBtu (3-hr average)* ~~*12.38 ppm$_{vd}$ @ 3% O_2*~~ ~~*0.76*~~*0.38 lb/hr (3-hr average)* ~~*0.19*~~*0.10 tons per rolling 12 months*

		NO_x	*Low NO_x burners* *Combustion of clean fuel* *Good Combustion Practices*	*0.06 lb/MMBtu (3-hr average)* *2.28 lb/hr (3-hr average)* *0.57 tons per rolling 12 months*
		GHG	*Good operating practices*	*CO_2 117 lb/MMBtu* *CH_4 0.0022 lb/MMBtu* *N_2O 0.00022 lb/MMBtu* *CO_2e ~~20,569~~ 1,115.31 tons per rolling 12 months*

Response to Comment #113:

The appropriate changes have been made consistent with Response to Comment #32 above.

Comment #114:

The commenter requested a revision of the source description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

Mixed Acid Plant

SN-44
Mixed Acid Plant Scrubber

Source Description

EDCC manufactures mixed acid by mixing ~~≤ 30%~~15% to 30% oleum (concentrated sulfuric acid) and/or 98% sulfuric acid with 98% nitric acid. The ~~≤ 30%~~15% to 30% oleum is purchased from a vendor and delivered to EDCC by railcar or tanker truck, while the 98% sulfuric acid will come from EDCC's Sulfuric Acid Plant, and the 98% nitric acid will come from EDCC's ~~Nitric Acid~~NACSAC Plant. The manufactured mixed acid is stored in the product storage tank or the mixing tank until it is loaded into a railcar or tanker truck. Air emissions from the tanks, the unloading of oleum, and the loading/unloading of the mixed acid into tank cars and/or trucks will be routed to the scrubber (SN-44) prior to being released to the atmosphere.

This scrubber is not subject to CAM because the scrubber is not used to control the NO_x emissions from this source.

Response to Comment #114:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #115:

The commenter requested the deletion of the hourly oleum offloading limit and mixed acid production limit in Specific Conditions 218 and 221 of the draft permit. The commenter also requested a revision of the associated hourly record keeping requirement in Specific Condition 223 of the draft permit. According to the commenter, short term emission limits (i.e., lb/hr limits) for sources at the Mixed Acid Plant are based on the maximum capacity of the equipment/process. The commenter stated that considering regulatory guidance related to practical enforceability, short term production limits and associated monitoring are not necessary to ensure permit compliance. The commenter noted that it has been the ADEQ's consistent practice in past permitting actions to exclude hourly production limits from permits when short term emission limits are based on the maximum capacity of the equipment/process. The commenter also stated that the installation, operation, and maintenance of monitoring devices sufficient to ensure accurate measurement of hourly production rates placed an unnecessary burden on EDCC relative to cost and manpower.

Response to Comment #115:

The emission calculations submitted on behalf of the facility indicate that this source will operate 8,760 hours per year. The short term maximum capacity was determined by taking the annual capacity 394,200 ton/yr and dividing by 8,760 hours per year of operation. This short term number does not represent a realistic short term maximum capacity for this source as claimed by the commenter. Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. The short term limits in the permit are necessary to demonstrate compliance with the short term emissions. Therefore, these conditions will remain as written in the draft permit. The Department would accept and review the appropriate modification application addressing the maximum short term capacity for this source.

Comment #116:

The commenter requested a revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff) and to provide clarification regarding the meaning of turndown rate.

Natural Gas Fired Boiler~~s~~

SN-61

Natural Gas Fired Start-up Boiler

Source Description

> *A 240 MMBtu/hr natural gas fired Startup Boiler (SN-61) is used to supply steam throughout the multi-plant facility~~various nitric acid, the ammonium nitrate plants, and the sulfuric acid plant~~ during startup operations and for process heating purposes when excess steam generated from the operating plants is not available. Emissions from the boiler occur due to the combustion of natural gas. This boiler is being permitted as a high turndown rate (10:1) boiler. The turndown rate represents the maximum firing rate of the burners compared to the lowest controllable firing rate at which the boiler can operate. This turndown rate is necessary to EDCC's operations due to the high variability in steam demand at the facility.*

Response to Comment #116:

The permit has been updated as requested.

Comment #117:

For Specific Conditions 227, 228, and 229, the commenter requested that the statement that the annual emissions are based on maximum capacity be updated to being permitted based on annual natural gas usage of the boiler.

Response to Comment #117:

The permit has been updated as requested.

Comment #118:

The commenter requested the BACT Analysis Summary found in Specific Condition 240 be updated consistent with the changes submitted on September 6, 2013 and September 12, 2013. The commenter stated that these changes include updating the N_2O limit from 0.0002 lb/MMBtu to 0.00022 lb/MMBtu, and updating the control technology for NO_x to include flue gas recirculation at the boiler.

Response to Comment #118:

The requested changes have been made.

Comment #119:

For Specific Condition 235, the commenter requested the deletion of the 60-month test frequency as it was redundant with the previous sentence.

Response to Comment #119:

The sentence will not be deleted as requested. The previous sentence was intended to be written with every 12 months instead of every 60 months as written in the draft permit. The permit has been updated to every 12 months as intended.

Comment #120:

The commenter requested that Specific Conditions 237, 238, and 239 be updated to the proper boiler heat input rating of 240 MMBtu/hr. The commenter also requested that the statement that the annual emissions are based on maximum capacity be updated to being permitted based on annual natural gas usage of the boiler.

Response to Comment #120:

The permit has been updated as requested.

Comment #121:

The commenter requested the BACT Analysis Summary found in Specific Condition 240 be updated consistent with the changes submitted on September 6, 2013 and September 12, 2013. The commenter stated that these changes included updating the N_2O limit from 0.0002 lb/MMBtu to 0.00022 lb/MMBtu, and updating the control technology for NO_x to include flue gas recirculation at the boiler.

Response to Comment #121:

The requested changes have been made.

Comment #122:

For Specific Condition 245, the commenter requested the deletion of the 60-month test frequency as it was redundant with the previous sentence.

Response to Comment #122:

The sentence will not be deleted as requested. The previous sentence was intended to be written with every 12 months instead of every 60 months as written in the draft permit. The permit has been updated to every 12 months as intended.

Comment #123:

The commenter requested the addition of NESHAP Subpart CCCCCC requirements to the Expansion Project Operating Scenario.

Response to Comment #123:

After the expansion project is completed, the facility will be a major source for hazardous air pollutants. NESHAP Subpart CCCCCC only applies to area sources; therefore, the permit will not be updated as requested, and will remain as written in the draft permit.

Comment #124:

The commenter requested the deletion of Nitric Acid Loading (SN-29) from the PSD permit. The commenter stated that the Nitric acid loading emissions have been routed to the Nitric Acid Vent Collection System (SN-10).

Response to Comment #124:

Even though the emissions from the source Nitric Acid Loading (SN-29) are routed to the Nitric Acid Vent Collection System (SN-10), the source still exists at the facility, and the associated compliance mechanisms for SN-29 are necessary to ensure compliance with the terms of the permit. The permit will remain as written except that the lb/hr and tpy emission limits have been removed and now contain a statement that the emissions are routed to SN-10.

Comment #125:

The commenter requested a revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-33
Nitric Acid Production Fugitives

Source Description

Fugitive emissions from the production, handling, mixing, blending decoloration, and storage of nitric acid are generated due to leaks in flanges, valve packings, etc. resulting in the release of nitrogen oxides and nitric acid mist. EDCC has nitrogen trioxide specifications for weak and strong nitric acid ranging from 0.~~06~~01% to 0.~~15~~05%.

Response to Comment #125:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #126:

The commenter requested that the annual emissions for SN-33 be updated from 0.01 tpy to 0.02 tpy for HNO_3 based on the updated emission calculations submitted on September 12, 2013.

Response to Comment #126:

The permit has been updated as requested.

Comment #127:

The commenter requested a revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-35
Magnesium Oxide Silo Baghouse

Source Description

The magnesium oxide silo baghouse (SN-35) pneumatically receives magnesium oxide powder from trucks and/or railcars and controls particulate matter from the unloading and storage operations. The baghouse is situated on top of the silo structure, which is approximately 50 feet tall.

Response to Comment #127:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #128:

The commenter requested a revision of the process description as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

SN-40
Ammonium Nitrate Solution Loading

Source Description

EDCC ships ammonium nitrate solution to customers via trucks and railcars. The content of the solution ranges from 83% to 90% ammonium nitrate. Ammonia emissions occur as a result of the loading of the trucks and railcars.

Response to Comment #128:

The permit has been updated as requested. The change was made in both operating scenarios.

Comment #129:

The commenter requested the addition of the gallons to tons conversion as indicated below. According to the commenter, EDCC tracks ammonium nitrate loading in terms of tons. The commenter stated that the conversion methodology is needed to confirm how compliance records will be generated to comply with the condition.

The permittee shall not load more than 65,000,000 gallons (383,500 tons at 11.8 lb/gal on an 85% solution basis) per rolling 12-month total of ammonium nitrate solution into railcars and/or trucks. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Response to Comment #129:

After additional correspondence with the commenter, the 11.8 lb/gal on an 85% solution basis is incorrect. Supporting documentation indicates that the maximum density of the solution would be 11.5 lb/gal. The permit has been updated with the following:

The permittee shall not load more than 65,000,000 gallons (373,750 tons at 11.5 lb/gal on an 85% solution basis) per rolling 12-month total of ammonium nitrate solution into railcars and/or trucks.

Comment #130:

The commenter requested the addition of SN-63 as a required source subject to the SSM requirements of Plantwide Condition 7 of the Expansion Project Operating Scenario.

Response to Comment #130:

SN-63 was added to Plantwide Condition 7.

Comment #131:

The commenter requested the deletion of the ambient monitoring requirements for ozone and NO_2 found in Plantwide Condition 10 of the Expansion Project Operating Scenario. It is the commenter's position that there is no basis for ozone and NO_2 monitoring as a result of the project. According to the commenter, the ambient air quality analysis conducted for NO_2 (and subsequently accepted by the ADEQ) indicated that the 1-hour NO_2 concentrations were well below the NAAQS in the near vicinity around the EDCC property. Therefore, the commenter stated that conducting ambient monitoring for NO_2 at or near the facility boundary would serve no useful purpose and places an unnecessary burden on EDCC relative to cost and manpower. According to the commenter, the results of the ambient air quality analysis demonstrated that any concentrations that were approaching the NAAQS were well away from EDCC's property, and thus should be examined by the ADEQ elsewhere in the region. Additionally, the commenter stated that the ozone analysis provided to the ADEQ (and subsequently accepted by the ADEQ) indicated that the expansion project at EDCC only resulted in a contribution of 0.00006 ppm ozone compared to the average background concentration for the region of 0.0748 ppm. According to the commenter, this minuscule contribution to the overall ozone concentration does not warrant the burden imposed on EDCC with the requirement to operate an ambient monitor.

Response to Comment #131:

Modeling is used as predictive tool to analyze the impacts from the modification. PSD rules specify that the Administrator may require the necessary Post-construction monitoring to determine the effect emissions from the modification may have, or are having, on air quality in any area. Furthermore, the PSD rules require the applicant to evaluate the local air quality via monitoring data for at least one year preceding receipt of the application. The applicant failed to complete the pre application monitoring analysis, and the background values used in the modeling analysis were not from a local monitor. The commenter is incorrect that ADEQ accepted the ozone analysis submitted. The permit does not contain any discussion regarding the ozone analysis for this modification. Therefore, it is appropriate for the facility to install, operate, and maintain the NO_x and Ozone monitors to verify that this modification does not cause or contribute to a violation of the NAAQS. The Department did not indicate that the monitors would be at the fenceline, and probably will not be located at the fenceline. The monitors should be placed at maximum impact area.

Comment #132:

The commenter requested a revision of the record keeping requirements as indicated below. According to the commenter, the NSPS Subpart DDDDD affected sources at EDCC are natural gas fired and are not subject to the emission or operating standards in the rule. Consequently, the commenter stated that there are no records required pursuant to §63.7555(a)(2).

36. You must keep records according to paragraphs (a)(1) ~~and (2)~~ of §63.7555.

a. A copy of each notification and report that you submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

b. ~~Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).~~

Response to Comment #132:

A review of 40 CFR Part 63, Subpart DDDDD (NESHAP) does not appear to contain an exemption from the requirements of §63.7555(a)(2) as stated by the commenter. A review of the General Provisions to 40 CFR Part 63 does not appear to contain an exemption for §63.10(b)(2)(viii). However, §63.10(b)(2)(viii) states:

"All results of performance tests, CMS performance evaluations, and opacity and visible emission observations"

There are currently no applicable performance tests, CMS performance evaluations, and/or opacity and visible emission observations required by NESHAP DDDDD for the applicable sources at this facility. The permit has been updated as requested.

Comment #133:

The commenter requested the deletion of the record keeping requirements as indicated below. According to the commenter, the NSPS Subpart DDDDD affected sources at EDCC are natural gas fired and are not subject to the emission or operating standards in the rule. Consequently, the commenter stated that there are no records required pursuant to references in Plantwide Conditions 38 through 42 below.

38. ~~You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown. [§63.7555(i)]~~
39. ~~You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown. [§63.7555(j)]~~
40. ~~Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1). [§63.7560(a)]~~
41. ~~As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [§63.7560(b)]~~
42. ~~You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years. [§63.7560(c)]~~

Response to Comment #133:

A review of 40 CFR Part 63, Subpart DDDDD (NESHAP) does not appear to contain an exemption from the requirements of §63.7555(i), §63.7555(j), §63.7560(a), §63.7560(b), or §63.7560(c) as stated by the commenter. The permit will remain as written.

Comment #134:

The commenter requested a revision of the Summary of Permit Activity as indicated below to accurately reflect the proposed equipment changes that are included in this permit modification as part of the Existing Units Operating Scenario.

Summary of Permit Activity

El Dorado Chemical Company (EDCC) owns and operates a chemical manufacturing facility located at 4500 North West Avenue in El Dorado, Arkansas. EDCC submitted a major prevention of significant deterioration (PSD) modification application to expand the facility. The PSD application changes can be found under Section II of the Expansion Project Operating Scenario. For the Existing Units Operating Scenario, the following changes are occurring with this modification:

1. Removal of the UHDE Direct Strong Nitric Acid Plant (SN-22);
2. Removal of the DSN Plant Cooling Tower (SN-39);
~~*2.*~~ *Removal of the KT Plant Cooling Tower (SN-43);*
3. Addition of the Haul Road Fugitive Emissions (SN-62); and
4. Addition of the diesel fire Emergency Water Pump (SN-65); and,
~~*4.*~~*5. Removal of the Nitric Acid Loading (SN-29); loading emissions have been routed to the Nitric Acid Vent Collection System (SN-10);*

Response to Comment #134:

All of the changes requested will be made except for the statement of the removal of the Nitric Acid Loading (SN-29). The Department understands that the facility claims that these emissions are captured and routed to the Nitric Acid Vent Collection System (SN-10); however SN-29 is the source of these emissions and will remain in the permit.

Comment #135:

The commenter requested that the Department update the Process Description under the Existing Units Operating Scenario to improve the accuracy of the process related information (as provided by EDCC staff) and to reflect CEMS monitoring requirements in the pending global settlement between the EPA/DOJ and LSB (EDCC's parent company).

Response to Comment #135:

The process description has been updated to include most of the requested changes.

Comment #136:

The commenter requested a revision of the process description for SN-08 and SN-09 to reference operation of the NO_x CEMS according to the CEMS Monitoring Plan is an element of a draft global settlement resolution pending final agreements between the US EPA and the

US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. According to the commenter, the East and West Nitric Acid Plants are covered sources in the global settlement.

Response to Comment #136:

The permit has been updated as requested.

Comment #137:

The commenter requested the deletion of Nitric Acid Loading (SN-29) from the PSD permit. Nitric acid loading emissions have been routed to the Nitric Acid Vent Collection System (SN-10).

Response to Comment #137:

The permit will not be updated as requested. See Response to Comment # 123.

Comment #138:

The commenter requested that the process description for SN-33 be updated to improve accuracy.

Response to Comment #138:

The permit has been updated as requested. See Response to Comment # 125.

Comment #139:

The commenter requested a revision of the emission limits for SN-33 as indicated below. According to the commenter, this change is consistent with the updated Emission Calculations submitted to the ADEQ on September 12, 2013.

SN	*Description*	*Pollutant*	*lb/hr*	*tpy*
33	*Nitric Acid Plants Fugitive Emissions*	NO_x	~~*0.1*~~*2.0*	~~*0.1*~~*8.5*

SN	Description	Pollutant	lb/hr	tpy
33	Nitric Acid Plants Fugitive Emissions	HNO_3	~~0.01~~2.00	~~0.01~~8.5

Response to Comment #139:

A review of the material submitted on September 12, 2013 indicates that the draft permit contains emission limits based on the emission calculations received on behalf of the facility. There was a typographical error concerning the annual HNO_3 emissions, which has been updated. The following table summarizes the emissions from SN-33:

SN	Description	Pollutant	lb/hr	tpy
33	Nitric Acid Plants Fugitive Emissions	NO_x	0.1	0.1
		HNO_3	0.01	0.02

Comment #140:

The commenter requested that the process description for SN-13 be updated to improve accuracy.

Response to Comment #140:

The permit has been updated as requested. See Response to Comment # 51.

Comment #141:

The commenter requested the deletion of the production based limit for N_2O in Specific Condition 333 of the draft permit. According to the commenter, SN-13 is not subject to BACT requirements; thus, a limit expressed in terms of lb/unit of production is not necessary. The commenter stated that the mass based limits and associated compliance demonstration requirements included in the permit are sufficient to demonstrate compliance relative to N_2O emissions. Also, the commenter requested a revision of the test frequency requirements as indicated below. According to the commenter, these changes are consistent with other testing requirements for new/modified sources in the permit.

~~The permittee shall not exceed the N_2O limit of 13.0 lb/ton at the DM Weatherly Nitric Acid Plant (SN-13).~~ The permittee shall have a third party stack test the N_2O emissions from SN-13 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup of the DM Weatherly Nitric Acid Plant (SN-13) after installation of the control equipment, and every 12 months thereafter. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. ~~The permittee shall have a third party stack test the N_2O emissions from SN-13 within 60 days of startup of the DM Weatherly Nitric Acid Plant (SN-13) after installation of the control equipment, and every 12 months thereafter.~~ The permittee shall

use EPA Method 320, ASTM D6348-03, or a method approved in advance by the Department. Testing shall be conducted with the source operating at least at 90% of its permitted capacity. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above.. Testing shall be conducted in accordance with Plantwide Condition 3. SN-13 has a maximum capacity rated at 16.7 ton/hr of acid production. [Regulation 19, §19.702 and §19.705; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; 40 CFR Part 52, Subpart E ; and 40 CFR 70.6]

Response to Comment #141:

Under Regulation 26, the Department is required to have all necessary monitoring requirements to assure compliance with the terms and conditions of the permit. The testing requirement will be removed, and compliance will be demonstrated through the use of the NO_x CEMS. It was presented to the Department that the existing NO_x CEMS has the capability to differentiate between NO_2 and N_2O emissions. The Department sees no reason to require the facility to stack test for the N_2O emissions from this source when the facility will be utilizing a NO_x CEMS. See Response to Comment #49 and Response to Comment #50 above.

Comment #142:

The commenter requested that the Department add the reference to the CEMS Monitoring Plan required by the global settlement between EPA/DOJ/LSB. According to the commenter, SN-13 is a covered source in the global settlement and must comply with the requirements of the CEMS Monitoring Plan included therein.

Response to Comment #142:

The Department agrees, and has added the additional reference to the CEMS Plan.

Comment #143:

The commenter requested addition of the reference to the CEMS Monitoring Plan required by the global settlement between EPA/DOJ/LSB as indicated below. According to the commenter, SN-13 is a covered source in the global settlement and must comply with the requirements of the CEMS Monitoring Plan included therein. Also, the commenter requested a revision of the CEMS requirements as indicated below. The commenter stated that these changes are consistent with the monitoring requirements in the CEMS Monitoring Plan included in the permit as Appendix J.

The permittee shall install, calibrate, maintain, and operate a dual range CEMS and stack gas flow meter to monitor NO_x emissions from the DM Weatherly Nitric Acid Plant (SN-13) in accordance with the CEMS Plan (listed as Appendix J in the back of this permit). The permittee shall install, calibrate, maintain, and operate the dual range monitor and ~~a~~ stack gas flow meter with the following operational requirements, which are included in the CEMS Plan:

Analyzer	Parameter	Location	Span Value
NO_x Stack Analyzers	NO_x, ppm by volume, dry basis[1]	Stack	Normal: 0 – 500 ppm NO_x, or as appropriate to accurately measure the normal concentration range. SSM: 0 to 125% of the maximum estimated NO_x emission concentration
Stack Flow meter	Volumetric Flow rate, SCFH[2]	Stack	0 to 125% of the maximum expected volumetric flow rate

[1]For the purposes of calculations under ~~this~~ the CEMS Plan in Appendix ??, as-is NO_x concentration measurements at ~~Covered Nitric Plants~~the DM Weatherly Nitric Acid Plant #1 (e.g., those utilizing FTIR, NDIR, or other types of stack gas analyzers capable of making wet measurements) will be assumed to be dry. However, ~~LSB~~ the permittee may adjust for any moisture contained in the stack gas if the nitric acid plant~~Covered Nitric Acid Plant~~ is equipped with a continuous moisture analyzer or equipment which removes the moisture prior to the stack gas analyzer.

[2]For the purposes of the calculations under ~~this~~ the CEMS Plan, as-is volumetric flow rate measurements will be assumed to be dry. However, ~~LSB~~ the permittee may adjust for any moisture contained in the stack gas if the ~~Covered Nitric Acid Plant~~nitric acid plant is equipped with a continuous moisture analyzer.

Response to Comment #143:

The permit has been updated as requested.

Comment #144:

The commenter requested a revision of the emission limits as indicated below. According to the commenter, this change is consistent with EDCC's current Title V Permit No. 0573-AOP-R15.

SN	Description	Pollutant	lb/hr	tpy
05	Ammonium Nitrate E2 Brinks Scrubber	PM_{10}	~~19.0~~14.1	*
17	E2 HDAN Plant Cooling Train	Exhaust from Pease Anthony Scrubber is routed to SN-05		

** - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.*

Response to Comment #144:

The permit has been updated as requested.

Comment #145:

The commenter requested that the process description for SN-28 be updated to improve accuracy.

Response to Comment #145:

The permit has been updated as requested. See Response to Comment # 84.

Comment #146:

The commenter requested the removal of Specific Condition 397. According to the commenter, SN-28 was not included as one of the particulate matter reduction projects used for netting purposes.

Response to Comment #146:

The permitted emission reductions were due to a new methodology for calculating emissions. There was a small increase in particulate matter emissions from this source that affected the total reductions from the netting analysis. This condition is not necessary and will be removed as requested.

Comment #147:

The commenter requested that the process description for SN-34 be updated to improve accuracy.

Response to Comment #147:

The permit has been updated as requested. See Response to Comment # 85.

Comment #148:

The commenter requested the deletion of the scrubber monitoring requirements as indicated below. According to the commenter, as it currently operates under the Operating Scenario # 2: Existing Units operating scenario, SN-14 is uncontrolled. The commenter stated that a Brinks scrubber will be installed on SN-14 prior to the end of the contemporaneous period, as this source was included in the list of particulate matter reduction projects used for netting purposes. The commenter stated that the monitoring parameters for the new Brinks scrubber are included in the Operating Scenario # 1: Expansion Project operating scenario requirements. The commenter noted that a revision to this draft permit has been proposed to require that the compliance requirements in Operating Scenario # 1 apply to the reduction projects upon startup, which will be before the Operating Scenario # 2 requirements expire.

Response to Comment #148:

The permit has been updated as requested.

Comment #149:

The commenter requested that the process descriptions for SN-15, SN-18, and SN-21 be updated to improve accuracy.

Response to Comment #149:

The permit has been updated as requested. See Response to Comment # 90.

Comment #150:

The commenter requested the revision of the source name for SN-15 from KT Plant Dryer/Cooler to KT Plant Dryer throughout the permit.

Response to Comment #150:

The permit has been updated as requested.

Comment #151:

The commenter requested the deletion of the requirement for the maximum dehydrator input rate. Based on information received from EDCC staff, the commenter stated that the other parameters are sufficient to confirm during testing that 90% of the maximum production rate is being achieved.

Response to Comment #151:

The change requested would be a significant change to an existing monitoring requirement, and cannot be changed without going through a public comment period. The facility is able to submit the appropriate modification application on a later date to address this issue.

Comment #152:

The commenter requested a revision of the source name in Specific Condition 417 of the draft permit as indicated below to improve the accuracy of the process related information (as provided by EDCC staff).

The KT ~~brinks~~ Brinks ~~scrubber~~ Scrubber (SN-21), the KT Plant Dryer~~/Cooler~~ Scrubber (SN-15), and the KT Plant Clay Baghouse (SN-18) shall be kept in good working condition at all times and shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-15, and SN-18, and SN-21 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to *demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parameter to be outside the range, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]*

SN	Description	Parameter	Units	Operation Limits
15	KT Plant Dryer/~~Cooler~~ Scrubber	Scrubber Liquor pH	-	0.5 – 4.5
		Liquid Flow Rate (combination of fan and ductwork)	gal/min	80 (minimum)
		Amperage	amps	290 (minimum)
18	KT Plant Baghouse	Gas Pressure Drop	in. H_2O	0.5 - 8.0
21	KT Brinks Scrubber	Liquid Gas Pressure to Top Spray Nozzles	psig	80 - 100
		Gas Pressure Drop Across Unit	in. H_2O	2.5 (minimum)
		pH	-	0.5 – 4.5

The commenter also requested the removal of SN-18 from Specific Condition 419 of the draft permit.

Response to Comment #152:

The permit has been updated as requested. The KT Plant Dryer/Cooler Scrubber (SN-15) is now named the KT Plant Dryer Scrubber (SN-15). The past actual $PM/PM_{10}/PM_{2.5}$ emissions from SN-18 were determined to be 3.5 tpy. The potential emissions from this source were determined to be 1.9 tpy. Specific Condition 418 requires the facility to reduce the emissions to a level no greater than the levels specified in Specific Conditions 134 and 135 before the end of the contemporaneous netting period. Even though this source is increasing the short term emission rates, this condition is necessary to ensure that the facility takes all the necessary netting reductions in accordance with 40 CFR 52.21. Specific Condition 419 will remain as written in the draft permit.

Comment #153:

The commenter requested deletion of the KT Plant Cooling Tower (SN-43) from the permit. According to the commenter, SN-43 will not operate during the Operating Scenario # 2 timeframe and is scheduled to be physically removed from the site.

Response to Comment #153:

SN-43 has been removed from the permit.

Comment #154:

The commenter requested that the process description for SN-44 be updated to improve accuracy.

Response to Comment #154:

The permit has been updated as requested. See Response to Comment # 114.

Comment #155:

The commenter requested that the process description for SN-35 be updated to improve accuracy.

Response to Comment #155:

The permit has been updated as requested. See Response to Comment # 127.

Comment #156:

The commenter requested that the process description for SN-40 be updated to improve accuracy.

Response to Comment #156:

The permit has been updated as requested. See Response to Comment # 128.

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0573-AOP-R16

IS ISSUED TO:

El Dorado Chemical Company
4500 North West Avenue
El Dorado, AR 71730
Union County
AFIN: 70-00040

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

November 24, 2010 AND November 23, 2015

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

NOV 18 2013

Date

Table of Contents

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

This permit represents two operating scenarios.

Scenario # 1: Expansion Project (beginning on page 7)

Scenario # 2: Existing Units (beginning on page 255)

The conditions of Operating Scenario # 2 shall apply to El Dorado Chemical Company until the Expansion Project has completed construction and has started operating. At that time, El Dorado Chemical Company shall cease operation under Operating Scenario # 2, and begin operations based on the conditions listed under Operating Scenario # 1. Some operations under Operating Scenario # 2 will no longer be applicable as existing sources are updated. Also, as emissions reductions projects are completed for those sources included in the contemporaneous netting for particulate matter, the conditions of Operating Scenario # 1 shall apply upon startup.

Expansion Project Operating Scenario

SECTION I: FACILITY INFORMATION

PERMITTEE:	El Dorado Chemical Company
AFIN:	70-00040
PERMIT NUMBER:	0573-AOP-R16
FACILITY ADDRESS:	4500 North West Avenue El Dorado, AR 71730
MAILING ADDRESS:	P.O. Box 231 El Dorado, AR 71730
COUNTY:	Union County
CONTACT NAME:	Kyle Wimsett
CONTACT POSITION:	Environmental, Health, and Safety Manager
TELEPHONE NUMBER:	870-863-1484
REVIEWING ENGINEER:	Joseph Hurt
UTM North South (Y):	Zone 15: 3680583.92 m
UTM East West (X):	Zone 15: 529356.41 m

SECTION II: INTRODUCTION

Summary of Permit Activity

El Dorado Chemical Company (EDCC) owns and operates a chemical manufacturing facility located at 4500 North West Avenue in El Dorado, Arkansas. EDCC submitted a prevention of significant deterioration (PSD) modification application to expand the facility. The PSD application included the following process equipment modifications:

1. Installation of a new DM Weatherly Nitric Acid Plant # 2 (SN-59);
2. Installation of a new cooling tower (SN-60) to support DM Weatherly Nitric Acid Plant #2,East Nitric Acid Plant, West Nitric Acid Plant , the NACSAC plant, and the Mixed Acid Plant; the existing cooling tower for the East and West Nitric Acid Plants (SN-42) will be removed from service;
3. Installation of three (3) new weak nitric acid storage tanks, which will be added to Nitric Acid Vent Collection System (SN-10);
4. Installation of a used Ammonia Plant and ancillary equipment (SN-49 through SN-51, and SN-54);
5. Installation of a new Ammonia Plant Cooling Tower (SN-52);
6. Installation of a new Ammonia Plant Ammonia Vent Flare (SN-53);
7. Installation of a new Ammonia Plant Process SSM Flare (SN-56) and a new Ammonia Storage Flare (SN-57);
8. Installation of a new ammonia storage tank, which will be added to the Ammonia Storage/Distribution (SN-32);
9. Installation of a new Ammonia Rail and Truck Loading (SN-58);
10. Installation of a new Start-up Boiler (SN-61);
11. Installation of a new ammonium nitrate neutralizer and chemical steam scrubber (SN-63);
12. Installation of a new E2 Ammonium Nitrate Brinks Scrubber (SN-05), which will control the existing emissions routed to SN-05 plus those from the E2 Ammonium Nitrate Prill Tower Fan (SN-06); the Pease Anthony Scrubber that had been in line with the existing SN-05 Brinks scrubber will be removed;
13. Installation of a new KT Ammonium Nitrate Brinks Scrubber (SN-14);
14. Installation of two (2) ammonium nitrate storage tanks, two (2) ammonium nitrate mix tanks, and a pH adjustment tank;
15. Installation of a new ammonium nitrate (solid prills) warehouse and associated handling equipment;
16. Installation of a new Nitric Acid Concentration (NACSAC) Plant (SN-47);
17. Removal of SN-06, as the emissions will now be routed to SN-05;
18. Removal of the two (2) existing boilers (SN-16A and SN-16B);
19. Removal of the UHDE Direct (Strong) Nitric Acid Plant (SN-22);
20. Removal of the DSN Plant Cooling Tower (SN-39); and
21. Removal of the KT Plant Cooling Tower (SN-43).

The total permitted emission increases include 1.4 tpy of SO_2, 179.4 tpy of VOC, 102.1 tpy of CO, 88.4 tpy of $PM_{2.5}$, 0.07 tpy of Lead, 2,481,140 tpy of CO_2e, 4,143.7 tpy of N_2O, 0.07 tpy of

Arsenic, 0.07 tpy of Cadmium, 0.40 tpy of Formaldehyde, 7.24 tpy of Hexane, 0.07 tpy of Mercury, 143.19 tpy of Methanol, and 446.27 tpy of Ammonia. The total permitted emission decreases include 213.9 tpy of PM, 239.7 tpy of PM_{10}, 1,689.9 tpy of NO_x, and 55.79 tpy of Nitric Acid.

Process Description

EDCC owns and operates a chemical manufacturing facility located in El Dorado (Union County), Arkansas. EDCC manufactures ammonia, nitric acid (various strengths ranging from 48% to 98.5%), sulfuric acid (93.0% and 98.0% strengths), high density grade ammonium nitrate (nitrogen fertilizer for agricultural use) and low density grade ammonium nitrate (for use in industrial applications). The main individual manufacturing processes at EDCC are described below.

Ammonia Plant

EDCC will install a newly acquired ammonia plant to operate at a maximum design capacity of 1,400 tons of ammonia production per day, or 511,000 tons per year. The plant produces anhydrous ammonia by reacting hydrogen with nitrogen over a catalyst at high temperature and pressure to form ammonia (NH_3). The plant is equipped with a gas-fired primary reformer with a maximum heat input capacity of 824 MMBtu/hr. The reformer is fired with a combination of pipeline quality natural gas and process off gas (purge gas).

The process begins with three common substances: natural gas, air, and water. To produce ammonia, these substances are combined in a high temperature environment in the presence of a catalyst to chemically react to form a gas stream consisting primarily of hydrogen, nitrogen, carbon monoxide, carbon dioxide and other gases. Using a series of catalysts and chemical solutions, all gases are removed with the exception of hydrogen and nitrogen. The commingled hydrogen and nitrogen, called synthesis gas, react under high pressure and in the presence of a catalyst to form ammonia gas. The ammonia gas is cooled by refrigeration and condensed to a liquid. EDCC uses this ammonia as a feedstock for its nitric acid and ammonium nitrate production processes. Excess ammonia is sold as product in trucks, railcar and through an ammonia pipeline.

Nitrogen for the production process is obtained from ambient air, while hydrogen is obtained from catalytic steam reforming of methane contained in natural gas. The process uses approximately 21,250 standard cubic feet of natural gas per ton of ammonia produced. The catalytic steam reforming method produces ammonia through six required steps:

1. Natural gas desulfurization
2. Catalytic steam reforming
3. Carbon monoxide shift
4. Carbon dioxide removal
5. Methanation
6. Ammonia synthesis ($3H_2 + N_2 \rightarrow 2NH_3$)

Natural Gas Desulfurization

Sulfur is a poison to many catalysts used in the ammonia synthesis process. The process gas desulfurizer removes sulfur contaminants by passing the natural gas feedstock through a layer of cobalt-molybdenum catalyst, which converts sulfur compounds to hydrogen sulfide (H_2S). The H_2S is then absorbed by a zinc oxide catalyst. Similarly, the fuel gas is desulfurized to reduce SO_2 emissions and to reduce potential corrosion from acid gases in the relatively cool exhaust streams in the convection section and induced draft stack.

Catalytic Steam Reforming

After desulfurization, the natural gas feed is mixed with steam and the mixture is sent to the primary reformer (SN-49). This process uses indirect heating produced by firing with a combination of pipeline quality natural gas and process off gas (purge gas). In the reforming process, approximately 56% of the methane contained in the natural gas feed is converted to hydrogen and carbon dioxide. The resulting gas mixture is then sent to a secondary reformer, where it is mixed with compressed air to form a final "synthesis gas" that has the desired hydrogen to nitrogen molar ratio and where the catalytic steam reforming is completed.

Carbon Monoxide Shift

Carbon monoxide is formed as a byproduct in the catalytic steam reforming process. After cooling, the carbon monoxide and water contained in the synthesis gas are converted to carbon dioxide and hydrogen in the High Temperature and Low Temperature Shift Converters. Unreacted steam is condensed and separated from the synthesis gas in a knockout drum, and the condensate is flashed in the Condensate Steam Stripper (SN-50) to remove volatile gases. The residual condensate may be returned to the boiler or reused in another portion of the process.

Carbon Dioxide Removal

After the carbon monoxide shift, the carbon dioxide is removed from the process gas by sending the synthesis gas through an absorption tower, where a methyl diethanolamine/piperazine solution (MDEA) is used to strip the carbon dioxide out of the gas. Carbon dioxide is removed from the MDEA in a stripper column (CO_2 Regenerator), where it is vented to the atmosphere (SN-51).

Methanation

The synthesis gas leaving the carbon dioxide absorber consists primarily of uncombined hydrogen and nitrogen, with residual amounts of carbon dioxide, methane, and carbon monoxide. Carbon dioxide and carbon monoxide are poisons to ammonia synthesis catalysts and must be removed. This is accomplished by passing the heated process gas over a catalyst, where the carbon dioxide and carbon monoxide are converted to methane and water.

Ammonia Synthesis

In the final step, the hydrogen and nitrogen-rich synthesis gas is converted to ammonia. The process is not 100% efficient, and some of the unconverted synthesis gas leaving this step is mixed with incoming raw synthesis gas and recycled back through the process. Synthesis gas from the methanation process is compressed, mixed with recycled synthesis gas, and then cooled. Any ammonia in the synthesis gas, which has condensed at this point in the process, is separated from the unconverted synthesis gas and sent to the separator. The unconverted synthesis gas is compressed, preheated, and then contacted with an iron oxide catalyst in the synthesis converter. Ammonia in the gas leaving the converter is condensed, and the ammonia is sent to a separator. Ammonia sent to the separator is flashed to remove impurities. The ammonia-rich flashed vapor is then condensed in a chiller, where anhydrous ammonia is removed and stored as a liquid at low temperature.

EDCC uses the liquid ammonia produced in the ammonia plant in any combination of the following ways:

1. Ammonia is used as a feedstock for on-site nitric acid production;
2. Ammonia is also used as a feedstock for on-site ammonium nitrate fertilizer production; and
3. Liquid ammonia is sold as product and shipped by truck and/or railcar (SN-58), or pipeline.

Ammonia Plant Cooling Tower

The Cooling Tower (SN-52) provides non-contact cooling water to the Ammonia Plant process equipment. Particulate matter is emitted during operation of the cooling tower.

Ammonia Plant - Ancillary Emission Sources

The following emission sources are operated in support of the ammonia plant production process:

- Frick Ammonia Compressors (SN-31)
  Fugitive emissions of ammonia occur from the handling of ammonia in the Frick Compressor Building.
- Ammonia Storage/Distribution (SN-32)
  Fugitive emissions of ammonia occur from the handling and distribution of ammonia.
- Ammonia Plant Ammonia Vent Flare (SN-53)
  Ammonia is vented from this source during emergencies or as a result of depressurization of the ammonia plant synthesis loop during shutdown or maintenance. The flare is operated to control ammonia during either of these events.
- Ammonia Plant Fugitives (SN-55)
  Fugitive leaks of process gas/liquid containing ammonia occur during normal operation from process equipment components (i.e., valves, flanges, pump seals, etc.).
- Ammonia Plant Process SSM Flare (SN-56)
  Process gas containing CO and methane is emitted during startup, shutdown, and malfunction (SSM) events. The flare is operated to control emissions during SSM events.
- Ammonia Storage Flare (SN-57)
  The flare is operated to control ammonia releases during planned maintenance and SSM events related to the ammonia storage tanks, ammonia refrigeration system, and the ammonia transfer system.

East and West Nitric Acid Plants

The East and West Nitric Acid Plants produce weak nitric acid at concentrations ranging from 52% to 58%. These nitric acid plants employ the DuPont single (high) pressure process designed and built in 1962 by C&I Girdler. Therefore, the East and West Nitric Acid Plants are not subject to NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants) since they were constructed prior to August 17, 1971. Liquid ammonia is received through a pipeline, by truck, and/or produced at the Ammonia Plant and sent to intermediate storage. From intermediate storage, ammonia enters a surge tank, where the liquid ammonia level is controlled. The surge tank aids in maintaining a steady flow and controls the ammonia pressure. Purge valves remove oil, water, and inert gases from the ammonia before it exits the bottom of the surge tank through two lines. The ammonia is then delivered through a level control valve to a vaporizer, where the ammonia is vaporized.

The ammonia vapor is transferred to the mixer pipe, where it is mixed with preheated air through a series of nozzles. The mixture is maintained at approximately 10% (by volume) ammonia gas. The air and ammonia mixture enters into the top of a converter, where combustion occurs on platinum catalyst gauze. The temperature of the gas leaving the platinum catalyst is between 1,660°F and 1,750°F. At this point, the ammonia is being oxidized to nitrogen oxide(s) and water vapor.

The process gas is then cooled prior to the absorption process. The process gas passes through absorption columns at the East and West Nitric Acid Plants. Product acid (52% to 58% nitric acid) is retrieved from the bottom of each absorption column and pumped to two 250 ton capacity stainless steel tanks. The tanks share a common vent stack with a water seal at the bottom.

The unabsorbed tail gas, which consists of nitrogen oxides, exits the top of the absorption columns and is passed through Selective Catalytic Reduction (SCR) Units before being vented to the atmosphere through a stack (SN-08 for the West Nitric Acid Plant and SN-09 for the East Nitric Acid Plant). The SCR Units reduce nitrogen oxide emissions by reacting ammonia with nitrogen oxide to form nitrogen gas and water vapor. The stacks are equipped with a nitrogen oxide continuous emission monitoring systems (CEMS), which shall be operated in accordance with the ADEQ CEMS conditions. The CEMS will also be operated consistent with proposed elements of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. The pending global settlement is intended to resolve United States' Clean Air Act (CAA) claims under the Prevention of Significant Deterioration (PSD) program, related to LSB's nitric acid manufacturing facilities. EDCC's East and West Nitric Acid Plants are covered facilities under the pending global settlement.

Fugitive nitrogen oxide emissions (SN-33) from the production, handling, mixing, blending, decoloration, and storage of nitric acid are generated through leaks in flanges, valve packing, etc. Also, nitric acid mist emissions occur due to the loading of nitric acid into rail cars and trucks. Emissions from loading operations (SN-29) are controlled by the Nitric Acid Vent Collection System (SN-10).

DM Weatherly Nitric Acid Plant # 1 (DMW1 Plant)

The DMW1 Plant (SN-13) produces weak nitric acid at a concentration of 61% - 67% by the oxidation of ammonia in the presence of a catalyst in a similar process to the East and West Nitric Acid Plants. This nitric acid plant was originally installed at the American Cyanamid Company facility at Hannibal, Missouri and was relocated to El Dorado Chemical in 1990. Therefore, this plant is subject to NSPS 40 CFR 60 Subpart G since it was constructed after August 17, 1971 and produces weak nitric acid (between 30% and 70% strength).

Liquid ammonia is received through a pipeline, by truck, and/or produced at the Ammonia Plant and sent to intermediate storage. From intermediate storage, liquid ammonia is passed through a set of filters into the ammonia feed vaporizer. Any particulates in the vapor are removed in the ammonia filter. A magnetic filter removes iron residue from the ammonia vapor. The clean ammonia vapor is directed to an ammonia superheater and heated to approximately 330°F. The hot/clean ammonia is conveyed into a Koch ammonia/air mixer, where the process of converting and oxidizing ammonia to nitric acid is initiated. The oxidation of the ammonia is completed as gases pass through a converter elbow. From the converter, the process gas is passed through a series of heat recovery units and then to the absorption column.

The absorption column is divided into three zones. Zone I is the lower part of the column, where the majority of the absorption of nitrogen dioxide to produce the largest amount of nitric acid occurs. Zone II contains a low nitrogen oxide concentration and oxidizes nitric oxide to nitrogen dioxide. Zone III, the upper zone (accounts for approximately 100 feet of the 154 foot column height) of the column, absorbs in condensate low concentrations of nitrogen dioxide, which lowers the nitrogen oxide emissions and allows the plant to produce a consistent 61% - 67% strength nitric acid stream.

The reaction gas stream exiting the top of the absorption tower ("tail/expander gas") is directed through a mist separator and tail gas preheater. The tail gas is routed through a series of heaters/preheaters before being routed to the No. 1 and No.2 Economizers. The economizer's exit stream (consisting of nitrogen, excess oxygen, and unabsorbed nitrogen oxides) is routed to a natural gas fired tail gas heater (SN-48) to increase the exit gas temperature and then to a SCR unit for NO_x control before being released to the atmosphere through a 50 foot stack (SN-13). The stack is equipped with a nitrogen oxide continuous emission monitoring system (CEMS), as required by 40 CFR Part 60 Subpart G. The CEMS will also be operated consistent with proposed elements of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. The global settlement is intended to resolve United States' Clean Air Act (CAA) claims under the Prevention of Significant Deterioration (PSD) program, related to LSB's nitric acid manufacturing facilities. EDCC's DMW1 Plant is a covered facility under the pending global settlement.

Fugitive nitrogen oxide emissions (SN-33) from the production, handling, mixing, blending, decoloration, and storage of nitric acid are generated through leaks in flanges, valve packing, etc. Also, nitric acid mist emissions occur due to the loading of nitric acid into rail cars and trucks. Emissions from loading operations (SN-29) are controlled by the Nitric Acid Vent Collection System (SN-10).

DM Weatherly Nitric Acid Plant # 1 Cooling Tower

The cooling tower (SN-38) provides non-contact cooling water to the DMW1 process equipment. Particulate matter is emitted during operation of the cooling tower.

DM Weatherly Nitric Acid Plant # 2 (DMW2 Plant)

The DMW2 Plant (SN-59) produces weak nitric acid at a concentration of 61% - 67% by the oxidation of ammonia in the presence of a catalyst. This nitric acid plant is being newly constructed at El Dorado Chemical; therefore, this plant is subject to NSPS 40 CFR 60 Subpart Ga since it was constructed after October 14, 2011 and produces weak nitric acid (between 30% and 70% strength).

Liquid ammonia is received through a pipeline, by truck, and/or produced at the Ammonia Plant and sent to intermediate storage. From intermediate storage, liquid ammonia is passed through a set of filters into the ammonia feed vaporizer. Any particulates in the vapor are removed in the ammonia filter. A magnetic filter removes iron residue from the ammonia vapor. The clean ammonia vapor is directed to an ammonia superheater and heated to approximately 330°F. The hot/clean ammonia is conveyed into an ammonia/air mixer, where the process of converting and oxidizing ammonia to nitric acid is initiated. The oxidation of the ammonia is completed as gases pass through a converter elbow. From the converter, the process gas is passed through a series of heat recovery units and then to the absorption column.

The absorption column is divided into three zones. Zone I is the lower part of the column, where the majority of the absorption of nitrogen dioxide to produce the largest amount of nitric acid occurs. Zone II contains a low nitrogen oxide concentration and oxidizes nitric oxide to nitrogen dioxide. Zone III, the upper zone of the column, absorbs in condensate low concentrations of nitrogen dioxide, which lowers the nitrogen oxide emissions and allows the plant to produce a consistent 61% - 67% strength nitric acid stream.

The reaction gas stream exiting the top of the absorption tower ("tail/expander gas") is directed through a mist separator and tail gas preheater. The tail gas is routed through a series of heaters/preheaters before being routed to a selective SCR unit to control NO_x emissions (SN-59) and then to the economizer. Tertiary controls are also utilized to control N_2O emissions in compliance with PSD BACT requirements. The stack is equipped with a nitrogen oxide continuous emission monitoring system (CEMS), as required by 40 CFR Part 60 Subpart Ga.

Fugitive nitrogen oxide emissions (SN-33) from the production, handling, mixing, blending, decoloration, and storage of nitric acid are generated through leaks in flanges, valve packing, etc. Also, nitric acid mist emissions occur due to the loading of nitric acid into rail cars and trucks. Emissions from loading operations (SN-29) are controlled by the Nitric Acid Vent Collection System (SN-10).

DM Weatherly Nitric Acid Plant # 2 and East and West Nitric Acid Plants Cooling Tower

The Cooling Tower (SN-60) provides non-contact cooling water to the process equipment in the DMW2 Plant, the East and West Nitric Acid Plants, the NACSAC® Plant, the Mixed Acid Plant, and the Ammonia shipping and storage refrigeration system. Particulate matter is emitted during operation of the cooling tower.

Nitric Acid Vent Collection System

In October of 1997, a packed tower hydrogen peroxide scrubber was installed to control NO_x emissions. The top portion of the packed tower treats nitrogen oxide emissions from the weak nitric acid storage vents (Tanks 49, 50, and 51, as well as three (3) new tanks being added with the plant expansion). The bottom section of the packed tower treats the nitrogen oxide emissions present in the blend acid tanks (Tanks 43, 44, 45, and 46) bleaching air stream. The nitric acid loading system vents (SN-29) are also collected and routed to the packed tower. The overheads from the packed tower are routed through a Venturi Scrubber for additional treatment before being vented to the atmosphere (SN-10). The strong nitric acid storage tanks (Tanks 47, 48, 66, 67, 68, 69, 70, and 71) are routed directly to the Venturi scrubber (i.e., bypass the packed tower).

Finally, the nitric acid fumes resulting from the cleaning and pressure checking of rail cars (conducted in the Car Barn) are routed to SN-10.

NACSAC® Plant

On May 14, 2012, a reactor at the Direct Strong Nitric Acid Plant (DSN Plant) exploded, causing irreparable damage to this process unit. EDCC will construct a nitric acid concentration plant (NACSAC® Plant) to replace the facility's strong nitric acid production capability that was lost due to the shutdown of the DSN Plant.

In the NACSAC® Plant, weak nitric acid is concentrated by atmospheric extractive reactivation in the NAC® Unit using sulfuric acid as the extractive agent. The sulfuric acid is diluted in the NAC® Unit as it extracts water from the feed nitric acid. The diluted sulfuric acid is re-concentrated in the SAC® Unit. All NO_x containing gases generated in the whole NACSAC® Plant are recovered as weak nitric acid in the NO_x-ABS Unit. The recovered nitric acid from the NOx-ABS Unit is sent to the NAC® Unit to be concentrated. The combined concentration of the feed acid and the weak acid from the NO_x-ABS Unit yields strong nitric acid (> 98% strength).

NAC® Unit

Weak nitric acid is pumped through an Internal Pre-Heater to the Nitric Acid Evaporator. The pre-heated nitric acid is only partly evaporated in the Nitric Acid Evaporator. The remaining boiling nitric acid and nitric acid vapors from the evaporator are fed to the Reactification Column, as well as pre-cooled sulfuric acid. On top of the Reactification Column, concentrated nitric acid is evaporated together with NO_x gas, which is generated as a the nitric acid decomposes due to the temperature in the column. The concentrated nitric acid is then routed to the Condenser, and the temperature of the remaining gas is further reduced in the Cooler to minimize the content of nitric acid vapors in the gas. Gas exiting the Cooler is routed to a Gas Washer, which scrubs out liquid nitric acid and water acid prior to the its entering the compressors feeding the NO_x-ABS Unit. The liquid recovered in Gas Washer is then recycled back to the Nitric Acid Evaporator.

The condensed nitric acid flows through Bleaching Column 1, where the condensed nitric acid is re-heated to its boiling point. By this procedure, the vapors are pre-cooled for greatest efficiency in a Condenser, and the simultaneous re-heating of concentrated nitric acid for best bleaching results in Bleaching Column 2 is achieved. The boiling, concentrated nitric acid from Bleaching Column 1 is bleached with compressed air in Bleaching Column 2 to achieve a colorless product nitric acid. The temperature of the bleached nitric acid from Bleaching Column 2 is then reduced in the Product Cooler.

In the sump of the Reactification Column, the diluted sulfuric acid is pre-concentrated in the Sump Re-Boiler to generate the vapors required for reactification. The vapors evaporate the nitric acid inside the Reactification Column and strip out almost all of the nitric acid and nitrous acid from the sulfuric acid, which then flows to the SAC® Unit.

SAC® Unit

Pre-concentrated sulfuric acid from the Sump Re-Boiler of the NAC® Unit flows to the SAC® Unit. The SAC® Unit consists of a Vertical Evaporator and Heat Exchanger. The SAC® Unit re-concentrates the diluted sulfuric acid, which then flows to the Buffer Tank. From the Buffer Tank, the concentrated sulfuric acid is pumped through the Internal Pre-Heater of the NAC® Unit to the Reactification Column.

Vapors generated in the SAC® Unit are condensed in the Condenser, from which water flows to the Condensate Dip Tank. The condensate is used to de-superheat the vapors in front of the condenser. The condensate is also used to separate in a separate cooling loop to cool the Vacuum Pump, which maintains the vacuum of the SAC® Unit. A small amount of the cooled condensate is pumped to the NO_x-ABS Unit for use as process water.

NO_x-ABS Unit

All NO_x generated in the NACSAC® Plant is sent to the Liquid Ring Compressors of the NO_x-ABS Unit. The Liquid Ring Compressor compresses the gas together with atmospheric air, which then flows to the Absorption Tower. The Absorption Tower utilizes specially designed trays with cooled inserts to provide for efficient oxidation and absorption of NO_x to generate nitric acid together with atmospheric air and water. Process condensate from the SAC® Unit is used to minimize the amount of effluent water.

At the bottom of the Absorption Tower, weak nitric acid is produced, which is sent to the Liquid Ring Compressor and for temperature reduction to the Cooler. The liquid stream is then sent for concentration in the NAC® Unit. The effluent gas, containing NO_x, is released from the top of the Absorption Tower directly to the atmosphere (SN-47).

Sulfuric Acid Plant

The Sulfuric Acid Plant was originally constructed in 1949 as a single absorption contact process of the Chemico design. The Sulfuric Acid Plant has now been converted to a double adsorption process with a maximum production capacity of 550 tons of 100% acid equivalent per day. To support the double absorption process, a Sulfuric Acid Cooling Tower (SN-46) is operated to maintain a consistent operating temperature.

There are three principal steps in the manufacturing process for sulfuric acid. First, elemental sulfur is removed from a storage tank and burned to form sulfur dioxide. Second, the sulfur dioxide is further oxidized utilizing a reactor with a vanadium pentoxide catalyst to form sulfur trioxide. Third, the sulfur trioxide is absorbed with water to form a 93-99% sulfuric acid solution. The gas stream exiting the absorption tower contains nitrogen, oxygen, un-reacted sulfur dioxide and entrained sulfuric acid mist. This stream enters a Brinks Mist Eliminator, which captures some of the sulfuric acid mist prior to the gases being exhausted to the atmosphere through a stack (SN-07). A more detailed process description is as follows.

The raw material used to initiate the sulfuric acid manufacturing process is elemental (Bright) molten sulfur. The elemental sulfur is delivered to EDCC by rail car or tank truck. The sulfur is unloaded into a heated pit and pumped to a 2,000 ton heated sulfur storage tank (included in the air permit as an insignificant activity). The sulfur storage tank is equipped with a control valve, which allows molten sulfur to back flow into the pump pit.

The molten sulfur is pumped from the heated pit to the Sulfuric Acid Plant for the combustion step. While the sulfur is being pumped from the heated pit, atmospheric air is passed through an electric drive blower and sent to a packed tower, where ambient moisture is removed by a recirculating 98% sulfuric acid stream. The pre-dried air is preheated to 420°F in a heat exchanger by waste heat from the first stage of the converter. The air enters the sulfur burner, where sulfur is sprayed into the air and is burned forming sulfur dioxide.

In the conversion step of the process, the sulfur dioxide in the gas stream is combined with some of the remaining oxygen to form sulfur trioxide. A waste heat reboiler located at the exit of the sulfur burner cools the gas exiting the sulfur burner. The sulfur dioxide is converted to sulfur trioxide in the converter, which consists of four layers of catalyst. The gas temperature increases as additional heat is evolved during the conversion process. The sulfur dioxide has the possibility of only partially converting to sulfur trioxide if the gas temperature increases. Therefore, the gases are cooled in three different places in the converter. The gases are cooled in a heat exchanger (which preheats the combustion air) after passing through the first layer of catalyst. Dry air from the 98% drying tower cools the gases as they pass through the second, third, and fourth catalyst layers before exiting the converter.

An economizer (i.e., heat exchanger) cools the gas leaving the converter. The cooling fluid is the incoming water used in the waste heat boiler. The sulfur trioxide made in the converter will not combine directly with water but must be combined indirectly through absorption with 93% sulfuric acid. Under this condition, the sulfur trioxide readily unites with water in the sulfuric acid. This operation is carried out in the absorption tower, where the sulfur trioxide is scrubbed out of the gas stream with 93% sulfuric acid. The gas stream exiting the absorption tower contains inert atmospheric nitrogen, excess oxygen, unreacted sulfur dioxide, and entrained sulfuric acid mist that is routed to the Brinks' Mist Eliminator, which captures sulfuric acid mist prior to the gases being exhausted to the atmosphere through a stack (SN-07).

The 93% sulfuric acid leaves the drying tower, where 98% sulfuric acid is weakened by water vapor removed from atmospheric air. The 93% sulfuric acid is strengthened by sulfur trioxide absorption. There is not enough atmospheric moisture in the air to supply all of the water required for combination with sulfur trioxide to form sulfuric acid. Before it is again pumped to the top of the towers, the absorbing acid is diluted with condensate to the desired strength for efficient sulfur trioxide absorption. This diluted acid is fed at the inlet of the cooler.

Stronger acid from the absorbing tower fortifies the acid from the drying tower, with the makeup being drawn off as product. All dilution condensate is added to the 93% sulfuric acid system. Due to the continuous formation of the greater than 98% sulfuric acid, the volume of acid in the circulation system is proportional to the amount of acid produced. A constant level is maintained by continuously removing 98% sulfuric acid from the pump tank. The removed acid is the production of the plant.

Sulfuric acid product is used as a feedstock to the Mixed Acid Plant and/or as an extractive agent in the NACSAC® Plant. The remainder is sold as product and shipped via rail cars or trucks. Loading losses (SN-30) (occurring as sulfuric acid vapors) are displaced to the atmosphere by the liquid being loaded into rail cars or trucks.

Sulfuric Acid Plant Cooling Tower

The Cooling Tower (SN-46) uses a combination of river water and cooling system condensation water to cool the heat generated by the sulfuric acid production process. Particulate matter is emitted during operation of the cooling tower.

E2 Ammonium Nitrate Plant

The E2 Ammonium Nitrate Plant has been in operation at EDCC since the 1950's. It was modified in the early 1980's to allow for the production of either high density ammonium nitrate (HDAN, fertilizer grade) or low density ammonium nitrate (LDAN, industrial grade). However, when the KT Ammonium Nitrate Plant was built in 1989, the production of LDAN at the E2 Plant was discontinued.

HDAN production requires the reaction of weak nitric acid with ammonia to produce an ammonium nitrate solution. The ammonium nitrate is concentrated to a strength greater than 99% for high density prills.

Weak nitric acid from one of the weak nitric acid plants (East and West Nitric Acid Plants, DMW1, and/or DMW2) and ammonia is reacted in one of three ammonium nitrate neutralizers (reactors) piped in parallel, or from a fourth standalone neutralizer. Overheads from the three neutralizers operated in parallel are routed to the E2 Plant Chemical Steam Scrubber (SN-41) for ammonia and particulate matter control. Overheads from the standalone neutralizer are routed to a second Chemical Steam Scrubber (SN-63), also for ammonia and particulate matter control. After the neutralization reaction, the ammonium nitrate solution (approximately 90% concentration) is fed to a sealed tank, where a pH analyzer adds enough ammonia to complete the reaction with the excess nitric acid. The ammonium nitrate solution then passes through two concentration steps (Low Concentrator and Auxiliary Concentrator) and then to Ammonium Nitrate Storage (SN-26) or directly to the E2 Plant Prill Towers. At each of the prill towers, the concentrated ammonium nitrate solution is broken into droplets by the prill plate; the droplets then fall countercurrent to cooling air forming prills. The air is pulled through the towers by the E2 Ammonium Nitrate Prill Tower Fans. The E2 Low Concentrator exhaust and the Auxiliary Concentrator exhaust are routed to the E2 Plant Chemical Steam Scrubber (SN-41), while the emissions from the Prill Tower shrouds and the Prill Tower fans (formerly SN-06) are routed to the E2 Plant Brinks Scrubber (SN-05). The prills are further cooled and screened when they exit the prill towers. The air from the post-prill tower cooling process is to SN-05 for control.

The cooled prills are loaded directly onto rail cars or trucks through a HDAN conveyor system (SN-28).

Ammonium Nitrate Solution Loading

Ammonium nitrate solution is shipped to customers via trucks and railcars. The content of the solution ranges from 83% to 90% ammonium nitrate. Ammonia emissions occur as a result of the loading operations (SN-40).

E2 Plant Barometric Tower

A wooden structure is operating similar to a cooling tower is used to create a "barometric leg" for the high concentrator (located at the top of the E2 Plant Prill Towers to concentrate ammonium nitrate from 95% strength to greater than 99% strength. The High Concentrator operates under a vacuum and non-condensables are pulled through the barometric leg to this dedicated Barometric Tower (SN-19). The Barometric Tower uses weak ammonium nitrate (~20%) process water as the circulation media. Particulate matter emissions occur as a result of particulate entrained in the water vapor mist that is emitted (sprayed) from the tower. Ammonia emissions also occur due the water containing ammonium nitrate in solution.

E2 Plant Solution Reactor

In the Solution Reactor (SN-34), a 35% nitric acid/magnesium oxide solution is created by reacting weak nitric acid with magnesium oxide through agitation. The solution leaves the reactor, where it is filtered to remove any excess magnesium oxide and other trace particulates, and is stored in a heated tank as 35% solution. The solution is pumped from the tank to the top of the E2 Prill Tower, where it is mixed with a 95% ammonium nitrate solution prior to the High Concentrator.

Magnesium Oxide Silo Baghouse

The Magnesium Oxide Silo pneumatically receives magnesium oxide powder from trucks or railcars. The baghouse (SN-35) is located on top of the silo structure and controls particulate matter from the unloading, storage, and material transfer operations.

KT Ammonium Nitrate Plant

The Kaltenbach Thuring (KT) Ammonium Nitrate Plant manufactures low-density ammonium nitrate for industrial customers. This plant was originally installed at American Cyanamid Corporation in Hannibal, Missouri and was purchased and relocated to El Dorado Chemical Company in1989.

Weak nitric acid from one of the weak nitric acid plants (East and West Nitric Acid Plants, DMW1 and/or DMW2) and ammonia is reacted in one of three ammonium nitrate neutralizers (reactors) piped in parallel, or from a fourth standalone neutralizer. The highly exothermic reaction of these two chemicals forms ammonium nitrate and steam. The ammonium nitrate solution exits the neutralizers to a pump tank, and the steam condensate is used in the nitric acid plants as an absorption medium. The ammonium nitrate solution is concentrated in the dehydrator to 97% concentration by blowing heated air through the solution. The concentrated ammonium nitrate solution is then pumped to the prilling tower. The overheads dehydrator stream is directed to a Brink's Scrubber (SN-21) prior to being vented to the atmosphere.

The prilling tower allows droplets of concentrated ammonium nitrate solution to fall for 150 feet countercurrent to ambient air. The droplets crystallize forming solid prills. Air and entrained particulate matter exit the top of the tower, where the particulate matter is controlled by a Brink's Scrubber (SN-14).

The solid prills are removed from the prilling tower and are sent to the predryer and dryer, where heated air is used to remove the remaining moisture. The exhaust air streams from the predryer and dryer are processed through a Ducon type wet scrubber (SN-15) equipped with a mist eliminator.

The prills are cooled and coated with a wax and talc coating to improve flowability. The cooler air is fed to the Brinks Scrubber (SN-21) for particulate matter removal. The talc is stored in an enclosed silo, which pneumatically feeds to the bulk talc hopper. The silo and hopper are equipped with a baghouse (SN-18) to control particulate matter emissions.

The finished product ammonium nitrate prill stream exits the coater through a discharge elevator into product loading bins. The product is transferred via conveyor to storage (SN-64) and/or into railcars or trucks (SN-27).

Mixed Acid Plant

The Mixed Acid Plant consists of mix tanks and storage tanks. The mix tanks and the storage tanks utilize a continuously operated scrubber that has 99.5% efficiency for controlling hexavalent sulfur. Periodically, the scrubber is used to bring product into specification, being replaced with fresh scrubber solution during scrubber operation.

EDCC manufactures mixed acid by mixing 15% - 30% oleum (concentrated sulfuric acid) and/or 98% sulfuric acid with 98% nitric acid. The 15% - 30% oleum is purchased from a vendor and delivered to EDCC by railcar or tanker truck, while the 98% sulfuric acid comes from EDCC's Sulfuric Acid Plant, and the 98% nitric acid will come from the NACSAC® Plant. The manufactured mixed acid is stored in the product storage tank or the mixing tank until it is loaded into a railcar or tanker truck. Air emissions from the tanks, the unloading of oleum, and the loading/unloading of the mixed acid into tank cars and/or trucks will be routed to the scrubber (SN-44) prior to being released to the atmosphere.

Startup Boiler

A natural gas fired Startup Boiler (SN-61) is used to supply steam throughout the multi-plant facility during startup operations and for process heating purposes when excess steam generated from the operating plants is not available. Emissions from the boiler occur due to the combustion of natural gas. EDCC's Start-up Boiler will be designed with a turndown rate of 10:1. The turndown rate represents the maximum firing rate of the burners compared to the lowest controllable firing rate at which the boiler can operate. This turndown rate is necessary to EDCC's operations due to the high variability in steam demand at the facility.

Gasoline Storage Tank

The Gasoline Storage Tank (SN-25) is used to fuel facility vehicles and equipment. Volatile organic compound emissions occur due to the fueling operations.

Haul Road Fugitives

Transport trucks and facility vehicles operate on unpaved roads at the facility. Particulate matter emissions occur due to the vehicle traffic (SN-62).

Prevention of Significant Deterioration (PSD)

With this application, EDCC proposes to construct multiple elements of a large facility expansion. Construction of production facilities includes the relocation of a used ammonia plant, a new nitric acid concentration plant (NACSAC® plant), a second (new) DM Weatherly nitric acid plant, a new ammonium nitrate neutralizer at the KT Plant, a new material curing and handling warehouse for LDAN product from the KT plant, a new start-up boiler, and two new cooling towers. Control equipment installations associated with the plants include a new chemical steam scrubber for the KT Plant (for PM and NH_3), three flares (for CO, NH_3, and methane), a Selective Catalytic Reduction (SCR) unit on the ammonia plant primary reformer (for NO_x), and a SCR unit and tertiary abatement system (for NO_x and N_2O, respectively) on the new DM Weatherly nitric acid plant. Maximum production rates at the existing plants will also be increased. These proposed changes will affect actual emissions from the facility. Facility sources considered "affected" as part of this analysis are SN-05, SN-06, SN-07, SN-08, SN-09, SN-10, SN-13, SN-14, SN-15, SN-18, SN-19, SN-21, SN-27, SN-28, SN-33, SN-34, SN-35, SN-38, SN-41, SN-44, SN-46, SN-47, SN-48, SN-49, SN-50, SN-51, SN-52, SN-53, SN-54, SN-56, SN-57, SN-59, SN-60, SN-61, SN-62, SN-63, and SN-64.

This project will result in CO, NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, and CO_2e emissions increases. The emission increases require review under the Prevention of Significant Deterioration / New Source Review (PSD/NSR) regulations in Arkansas Regulation 19.901 and 40 CFR 52.21.

A "major modification" is defined as a physical change or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source. A significant net emissions increase is defined by the PSD regulations for each pollutant. These thresholds are commonly referred to as the PSD Significant Emission Rates (SERs). The emissions increases related to this project are summarized below:

Expansion Project Emissions Increases	CO	NO_x	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e	Lead	VOC
Project Emissions Increase (tpy)	188.2	213.2	74.3	60.4	56.5	119.3	1,820,877	0.0024	182.7
PSD SERs (tpy)	100	40	25	15	10	40	75,000	0.6	40
Contemporaneous Netting Required?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes

PSD Netting Analysis -

As shown above, the PSD SERs are exceeded for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, and CO_2e. If contemporaneous emission decreases are available, emissions netting can be performed to determine if the overall net emissions increase for these pollutants is below their respective SERs (considering both contemporaneous and creditable increases and decreases). To that end, EDCC is exercising its option to conduct a significant net emissions increase analysis, or netting analysis, relative to particulate matter emissions (i.e., PM, PM_{10}, $PM_{2.5}$). Pursuant to 40 CFR 52.21(b)(3), the net emissions increase must include all creditable, contemporaneous emissions increases and decreases. Relative to the proposed project, the contemporaneous period is defined as starting from the date five years before construction commences to the date that the emissions increases from the project occur (i.e., commences operation). The contemporaneous period is projected to begin on November 1, 2008 (five years before the projected construction start date of November 1, 2013) and end on January 1, 2015 (when operation is projected to commence).

Due to the expansive nature of the proposed project, there were no emissions increases other than those associated with the project during the contemporaneous period. To support a positive netting outcome for $PM/PM_{10}/PM_{2.5}$, EDCC has elected to voluntarily implement the following emissions reductions options during the contemporaneous period:

- Replace the existing Brinks scrubber on the E2 Plant Prill Tower shrouds (SN-05) with a new, high efficiency Brinks scrubber,
- Route the E2 Ammonium Nitrate Prill Tower fans (SN-06), currently an uncontrolled source, to the new Brinks scrubber on SN-05,
- Install a new, high efficiency Brinks scrubber on the KT LDAN Prill Tower (SN-14),
- Install a new, high efficiency Brinks scrubber on the KT Plant Dryer/Cooler (SN-15), and
- Upgrade the existing Brinks scrubber on the KT Plant overheads dehydrator stream (SN-21) to achieve a control efficiency equivalent to a new, high efficiency Brinks scrubber.

In addition, EDCC will remove the following existing equipment/sources from service during the contemporaneous period:

- Boiler No. 2 (SN-16A) and Boiler No. 4 (SN-16B),
- DSN Plant Cooling Tower (SN-39),
- East and West Nitric Acid Plants Cooling Tower (SN-42), and
- KT Plant Cooling Tower (SN-43).

EDCC proposes that the equipment/source related changes indicated above be included in the PSD permit, such that the emission decreases are credible according to PSD netting requirements. Detailed emission calculations and a spreadsheet summarizing the results of the significant net emissions increase analysis are included in the application. As demonstrated in the spreadsheet summary included in the application, the significant net emissions increase analysis indicates the proposed project will not result in PM, PM_{10}, or $PM_{2.5}$ emissions exceeding their respective PSD Significant Increase Levels. The PSD netting analysis in summary includes net reductions of 86.5 tpy of PM, 37.9 tpy of PM_{10}, and 5.1 tpy of $PM_{2.5}$.

Best Available Control Technology (BACT) Analysis

Under the Federal Prevention of Significant (PSD) rules contained in Title 40 of the Code of Federal Regulations Part (40 CFR) 52.21(j), each new major source and/or major modification must employ Best Available Control Technology (BACT) for each pollutant for which the new source or modification is considered major. BACT is defined in 40 CFR 52.21(b)(12) as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any ... source ... which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs."*

A BACT analysis has been provided for each new or physically modified emissions unit for each pollutant exceeding an applicable PSD SER, which includes carbon monoxide (CO), nitrogen oxides (NO_x), volatile organic compounds (VOC), sulfur dioxide (SO_2), and carbon dioxide equivalent (CO_2e). Per 40 CFR 52.21(j)(3), a BACT analysis is only provided for an emissions unit if the emissions unit also experiences a net emissions increase.

If the source is subject to a New Source Performance Standard (NSPS), the minimum control efficiency to be considered BACT must result in an emission rate less than or equal to the NSPS emission limit. Thus, before a BACT analysis is performed, the applicable NSPS emission limits must be determined.

BACT Methodology

In a memorandum dated December 1, 1987, the United States Environmental Protection Agency (U.S. EPA) stated its preference for a "top-down" analysis. After determining if any NSPS is applicable, the first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented below are the five basic steps of a top-down BACT review as identified by the U.S. EPA.

STEP 1 – Identify all control technologies

Available control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: 1) researching the Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, 2) surveying regulatory agencies, 3) drawing from previous engineering experience, 4) surveying air pollution control equipment vendors, and 5) surveying available literature.

STEP 2 – Eliminate technically infeasible options

After the identification of control options, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control technology or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits, such as an NSPS.

STEP 3 – Rank remaining control technologies by control effectiveness

Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option or if all of the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

STEP 4 – Evaluate most effective controls and document results

Beginning with the most efficient control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control efficiencies.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the EPA's *OAQPS Control Cost Manual* (CCM) and other industry resources.

STEP 5 – Select BACT

In the final step, one pollutant-specific control option is proposed as BACT for each emission unit under review based on evaluations from the previous step.

The U.S. EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether the "top-down" approach is used. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."

The potential increase in CO, NO_x, SO_2, VOC, and CO_2e emissions resulting from the proposed and modified emissions sources at El Dorado Chemical Company will exceed the respective PSD significant emission rates. Therefore, the CO, NO_x, SO_2, VOC, and CO_2e emissions from the expansion project are subject to a BACT analysis.

DM Weatherly Nitric Acid Plant # 2 (SN-59)

Nitrogen Oxides (NO_x)

Step 1: Identify All Control Technologies

The following processes are options for controlling NO_x emissions from the type of nitric acid manufacturing facility to be installed at EDCC.

- Uhde EnviNO_x
- Dry absorption
- SCONOX™
- Hydrogen peroxide injection to the absorption column
- Molecular sieve adsorption
- Selective catalytic reduction (SCR)
- Non-selective catalytic reduction (NSCR)
- Urea scrubbing
- Refrigerated extended absorption
- Caustic scrubbing
- Ammonia scrubbing

A search of the RBLC and other published sources was conducted to identify candidate control technologies for controlling NO_x emissions from nitric acid plants. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
EPA Report (1991)[1]	First Chemical Corporation Pascagoula, Mississippi	Extended Absorption w/ SCR	Unknown	<60 ppm 0.57 lb/ton
RBLC ID: LA-0108	Arcadian Fertilizer LP Geismar, Louisiana	NSCR	January 1997	~132 ppm 2.14 lb/ton (Primary)[2] 3.0 lb/ton (Secondary)
RBLC ID: OK-0034	Terra Nitrogen Woodward, Oklahoma	SCR	February 1998	~200 ppm 3.0 lb/ton
Operating Permit	Terra Nitrogen Verdigris, Oklahoma	SCR	Unknown	~200 ppm 3.0 lb/ton
Operating Permit	El Dorado Nitrogen El Dorado, Texas	Extended Absorption w/ SCR	1999	~20 ppm 0.3 lb/ton[3]
Operating Permit	KOCH Nitrogen Enid, Oklahoma	Extended Absorption w/ NSCR	Unknown	~79 ppm 1.1 lb/ton
RBLC ID: WA-0318	Agrium U.S., Inc. Kennewick, Washington	NSCR + SCR (Plant 7) H_2O_2 Injection (Plant 9)	August 2004	~40 ppm/0.524 lb/ton ~20 ppm/0.3 lb/ton[3]
RBLC ID: GA-0109	PCS Nitrogen Fertilizer Augusta, Georgia	NSCR	May 2005	~200 ppm 3.0 lb/ton
Operating Permit	Coffeyville Resources Nitrogen Fertilizers, LLC Coffeyville, Kansas	Extended Absorption w/ SCR	August 2007	~45 ppm 0.6 lb/ton
US District Court/EPA Compliance Order	Royster Clark/Agrium North Bend, Ohio	Extended Absorption w/ SCR	February 2007	~40 ppm 0.6 lb/ton
RBLC ID: WA-0318	Agrium U.S., Inc. Kennewick, Washington	NSCR + SCR (Plant 7) H_2O_2 Injection (Plant 9)	July 2008	~40 ppm/0.524 lb/ton ~40 ppm/0.6 lb/ton[4]
RBLC ID: OK-0134	Pryor Chemical Company Pryor, OK	Extended Absorption w/NSCR	February 2009	1.6 lb/ton (2 units) 2.5 lb/ton (1 unit)

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
RBLC ID: ID-0017	Southeast Idaho Energy American Falls, ID	SCR	February 2009	1.12 lb/ton
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA	Uhde EnviNO$_x$	October 2012	5 ppm

[1]Alternative Control Techniques Document – Nitric and Adipic Acid Manufacturing Plants, EPA-450/3-91-026, EPA, Research Triangle Park, N.C. (Dec. 1991) – included in Attachment B
[2]Primary limit taken to attain compliance with NAAQS
[3]Interim limit subject to results of innovative technology review of proposed hydrogen peroxide injection process
[4]Revised limit based on final results of innovative technology review of hydrogen peroxide injection process

Step 2: Eliminate Technically Infeasible Options

As part of the BACT analysis, the control technologies identified as part of Step 1 are reviewed for their technical feasibility. A control technology is considered to be technically feasible if it has been previously installed and is in practice at a similar source and/or process and is operating successfully.
The NO_x emission control technologies listed below are not feasible for BACT-level emission control for nitric acid plants. A brief statement addressing the feasibility of each option is provided. A more detailed discussion of these options is included in Section 2.3 of the Technical Supplement Document (TSD) issued by the Washington State Department of Ecology (WSDE) for the Agrium facility located in Kennewick, Washington. For the Uhde EnviNO$_x$ technology, the technical feasibility issue is further addressed below.

Dry absorption

The only dry absorption technology that is available is the Pahlman Process. The Pahlman Process uses a proprietary formulation of manganese dioxide to absorb NO_x and SO_2 in the form of manganese nitrate and manganese sulfate. The manganese nitrate is regenerated to manganese dioxide in a proprietary process. Demonstration projects using a skid-mounted pilot unit showed a NO_x reduction of over 95%. There have been no commercial applications yet in any industrial sector, thus dry NO_x absorption is considered to be technically infeasible.

SCONOX™

The SCONOX™ NO_x control process consists of passing the exhaust combustion gases across a solid reactant surface. SCONOX™ reduces NO_x by reacting it with potassium carbonate, and reducing the resulting potassium nitrate with hydrogen to form N_2. SCONOX™ has been applied in practice only to small-to-medium sized electricity-generating gas turbines. EPA Region I describes the system's applicability as limited to natural gas-fired combined cycle turbines using water injection. The emission characterization from a nitric acid plant is dissimilar to sources where SCONOX™ applications are currently in use. Because SCONOX™

is currently limited to a different application, as well as the dissimilar nature of emission streams, it is considered technically infeasible.

Hydrogen Peroxide Injection

Hydrogen peroxide injection was initially listed in the RBLC as an experimental system proposed by Agrium under the innovative control technology review guidelines. The hydrogen peroxide injection system developed for the Kennewick facility was a proprietary, site specific design. Because the hydrogen peroxide injection system is not commercially available, it is considered to be technically infeasible for NO_x control purposes at EDCC.

Molecular sieve adsorption

Molecular sieve adsorption consists of adsorbing NO_x from a chilled tail gas exhaust stream onto selective adsorbent resin beads, desorbing the NO_x at a higher concentration than it had been in the original exhaust stream into a heated tail gas stream, and recycling the NO_x to the nitric acid process. There have not been any applications to full-size nitric acid plants, and research on this technology has been abandoned. Therefore, molecular sieve adsorption is considered technically infeasible.

Urea scrubbing

Urea scrubbing is a chemical scrubbing technology for NO_x reduction. Currently, urea scrubbing for NO_x reduction has not been demonstrated in practice. As a result, urea scrubbing is considered to be technically infeasible.

Currently, the following NO_x control technologies are considered to be technically feasible for nitric acid plants. These findings are consistent with the EPA's findings (with the exception of caustic scrubbing/ammonia scrubbing) in its published document Alternative Control Techniques Document – Nitric and Adipic Acid Manufacturing Plants, which states that *"Three control techniques are predominantly used to reduce the level of NO_x emissions in the tail gas [of nitric acid plants in the United States]: (1) extended absorption, (2) non-selective catalytic reduction (NSCR), and (3) selective catalytic reduction (SCR)."*

- Refrigerated extended absorption
- Caustic scrubbing/ammonia scrubbing
- Non-selective catalytic reduction
- Selective catalytic reduction
- Uhde EnviNO_x

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Based on the BACT emission levels listed in the RBLC and the additional information provided herein, the NO_x control efficiencies for the candidate NO_x control options can be ranked as follows:

- Uhde EnviNO$_x$ or refrigerated extended absorption with a SCR
- NSCR unit with a SCR unit
- SCR unit only
- NSCR unit only

Uhde EnviNO$_x$: This control equipment, in the first step of its Variant 2 process, uses an iron zeolite catalyst bed with ammonia to remove NO$_x$. Uhde promotional literature claims that NO$_x$ emissions consistently below 5 parts per million (ppm) have been demonstrated using its Variant 2 process. One facility was identified with the Uhde EnviNOx system as BACT to control NO$_x$ emissions. The Uhde EnviNO$_x$ system that was permitted as part of the Iowa Fertilizer Company PSD permit and ultimately was listed in the RACT/BACT/LAER Clearinghouse claims a NO$_x$ limit of 5 ppm, which correlates to 0.054 lb NO$_x$/ton acid on a 30-day rolling averaging period, exclusive of emissions related to startup, shutdown, and malfunction (SSM).

Refrigerated extended absorption with SCR: This control option involves extended absorption equipment followed by an add-on SCR unit to control NO$_x$ emissions. Four facilities were identified with extended absorption equipment and a SCR unit as BACT for the control of NO$_x$ emissions. According to the RBLC/other information sources, BACT limits for the four facilities range from 0.3 lb/ton acid produced to 0.6 lb/ton acid produced. However, based on EDCC's design engineer's review, it is believed that a control system utilizing extended absorption with a SCR unit at DMW2 can feasibly achieve a BACT limit of 5 ppm$_v$.

NSCR with SCR: This control option includes a NSCR unit followed by a SCR unit to control NO$_x$ emissions. One facility was identified as having this BACT control configuration and was required to achieve a NO$_x$ emission rate of 0.524 lb/ton acid produced.

It should be noted that NSCR is no longer favored as BACT for NOx reduction at nitric acid plants. NSCR systems were considered BACT for NOx in the 1970s and early 1980s when many nitric acid plants were built. NSCR systems are energy intensive (requiring significant hydrocarbon usage) and were designed around the general heat balance for the specific nitric acid plant. Due to the high temperature environment within the NSCR, some nitric acid plants fitted with this technology are achieving very low NOx emissions. (BREF - Inorganic Chemicals: Ammonia, Acids and Fertilizers, Section 3.4.8).

However, as NSCRs are integrated into the nitric acid plant heat balance, they are not simply add-on technologies for existing and or new nitric acid plants. The BREF document states (page 131) that, "*... the application [of NSCR] in existing plants will demand major adjustments, making the installation of an NSCR less feasible*". In addition, due to the significant hydrocarbon usage, NSCR systems create significant CO_2 emissions. At the time NSCR systems were considered BACT for NO$_x$, CO_2 emissions were not regulated and simply not a concern. In summary, the BREF document does not consider NSCR BACT for NO$_x$ due to cross-media effects, namely the additional consumption of natural gas/methane (hydrocarbons), which will give rise to more CO_2 emissions, and methane slip, as well as unreacted ammonia.

Refrigerated extended absorption with NSCR: This control option involves extended absorption equipment followed by an add-on NSCR unit to control NO_x emissions. Two facilities were identified as having this BACT control configuration with the minimum being required to achieve a NO_x emission rate of 1.1 lb/ton acid produced.

SCR or NSCR: This control option involves the installation of a stand-alone NSCR unit or SCR unit to control NO_x emissions. Three facilities were identified with either a NSCR unit or SCR unit as BACT for the control of NO_x emissions. According to the RBLC/other information sources, these facilities were required to achieve a NO_x emission rate of 3.0 lb/ton acid produced. One facility, located in Geismar, Louisiana, was required to achieve a NO_x emission rate of 2.14 lb/ton acid produced. As noted in the table in Step 1, this facility was required to achieve additional NO_x reductions beyond similarly controlled units to demonstrate compliance with the NAAQS.

Refrigerated extended absorption: Refrigerated extended absorption may be considered to be a NO_x control process or simply a mechanism for improving nitric acid yield. Because of EDCC's DM Weatherly design, which employs extended absorption, the practical limit for the NO_x concentration is close to that attainable when utilizing refrigerated extended absorption. Therefore, in this condition refrigerated extended absorption (with an SCR) is no more effective as a pollutant reduction technology as the DM Weatherly extended absorption design (with an SCR).

Caustic scrubbing/ammonia scrubbing: Caustic and ammonia scrubbing have a lower potential for NO_x removal from a nitric acid plant than those discussed above.

Step 4: Evaluate Most Effective Controls and Document Results

According to the RBLC/other information sources, the most effective NO_x control technology(s) is the Uhde EnviNO_x system or extended absorption with SCR unit at 5 ppm_v on a 30-day average, excluding SSM related emissions. The second best technology ranked in terms of effectiveness is a NSCR unit followed by a SCR unit at 0.524 lb/ton acid produced. The next most effective control technologies, in order, are SCR or NSCR, extended absorption, and caustic scrubbing/ammonia scrubbing at a NO_x emission rate of 2.14 lb/ton of 100% acid produced or above.

The Uhde EnviNO_x system is considered technically feasible to control NO_x emissions from a nitric acid plant to a 5 ppm_v level. This statement based on Uhde promotional literature and information from Uhde controlled nitric acid plants outside the United States. An EnviNOx system has not been installed, nor is one currently operating at a nitric acid plant in the United States. As indicated previously, one permit for a nitric acid plant utilizing this technology has been issued in the United States to date (i.e., to the Iowa Fertilizer Company), and that plant has not yet been constructed. In addition, to the best of Weatherly, Inc.'s knowledge the Uhde EnviNO_x system has never been installed on a Weatherly, Inc. designed nitric acid plant.

Relative to the SCR unit, the SCR catalyst vendors have supplied designs and have provided guarantees that the 5 ppm_v limit can be achieved under the conditions specified on the Weatherly, Inc. data sheets, provided the following criteria are met:

- The NO_2/NO_x ratio is 50% or less. This ratio governs the rate of reaction of NO_x to N_2 and H_2O; higher ratios of NO_2/NO_x (i.e., > 50%) decrease the reaction rate.
- Near perfect mixing and distribution of the ammonia and tail gas mixture across the catalyst bed is maintained. To achieve catalytic reduction of NO_x to a low level of 5 ppm_v, the key is to ensure there is excess ammonia mixed with the NO_x at the catalyst site. If the mixture of ammonia and NO_x is not homogenous and not evenly distributed over the catalyst bed, then some of the NO_x will slip by unconverted. The catalyst vendor requires <15% [RMS] maldistribution and an NH_3/NO_X maldistribution of < 2% absolute.
- Maximum inlet NO_X concentration of 1,000 ppm.
- The CEMS measurement technology is sufficient to accurately measure NO_X in the range of 0-5 ppm_v.

The vendor will guarantee the catalyst performance at nominal and maximum flow rates and NO_X content as specified. Based on the design engineer's review, EDCC believes that the technology is feasible and available, but like the Uhde EnviNO_X system, has not yet been demonstrated in a Weatherly, Inc. designed plant. In addition, the plant will be required to operate between 770 tpd and 1,265 tpd in response to fluctuating market conditions. Although the 5 ppm_v limit is considered technically achievable to ensure compliance over the long term, as well as the entire range of operating rates, it is noted here that the vendor claims significant uncertainty exists relative to an acceptable BACT compliance margin due to the potential for:

- Non-homogenous mixture of NO_x and ammonia feed to the SCR unit. The mixer is designed for the nominal operating rate, and as you deviate from that rate, the mixing efficiency will decrease.
- Catalyst deactivation and/or fouling over time. Although catalyst has a 60 month life, fouling in some areas can occur resulting in reduced efficiency. As the catalyst approaches its end of life, NO_x reduction performance will drop off.
- The range of the operating rates of the absorption tower (770-1,265 tpd). The ratio of NO_2/NO_x exit the absorber can vary with production rate. This variability will negatively impact the reaction rate in the SCR unit and reduce control efficiency.
- The NO_x concentration to the inlet gas to the SCR unit. The NO_X concentration is directly dependent on the operation of the absorber columns and the concentration of nitric acid being made. There are a number of variables that impact the absorption efficiency including operating pressure, cooling water temperature, quantity of excess oxygen, and inlet gas temperature. Operating pressure has one of the largest impacts on absorption efficiency. In the Weatherly, Inc. design, this pressure is not directly controlled but is a function of the discharge of the air compressor. Change in ambient conditions results in changes in compressor discharge pressure, which changes column pressure. This change in column pressure can result in variation of the NO_x

concentration in the inlet gas to the SCR unit. For a given air flow rate (this also sets the production rate), the absorber pressure is set by the compressor operation.

- NO_x to bypass the reduction catalyst. The SCR catalyst is supplied in multiple forms, either as honeycomb or as a bulk bed of pellets. Each type of installation has the potential for bypassing. The NO_x laden gas is forced through the catalyst bed, and gaskets are used to seal off those areas between the catalyst and the vessel walls. However, during the course of operation, the gasket material can degrade, thereby creating the potential for bypassing. A Weatherly, Inc. designed plant requires change out of the ammonia to NO_x converter catalyst every ninety days, as the catalyst is consumed during the reaction. This means that every ninety days or less, the SCR vessel will cycle from ambient conditions to 520 ^oF, which results in thermal growth and potential wear on the gaskets and other mechanisms used to eliminate bypassing.

Uncertainty also exists in the context of ancillary emissions. Ammonia is used as a reactant in the SCR unit to support NO_x reduction. To account for a proper excess amount of ammonia that is introduced to the control system to complete the reduction reaction, ammonia slip has been included in the PSD permit with limits of 2.64 lb/hr and 11.54 ton/yr. The ammonia limits were calculated based on a design based factor for ammonia slip of 10 ppm_v, or 0.5 lbNH_3/ton of 100% nitric acid produced. As the BACT limit for NO_x is decreased to the 5 ppm_v level, the potential exists for increased ammonia slip. For that reason, the catalyst vendors have stated that up to a 20 ppm_v ammonia slip could occur, especially during periods of SSM.

Step 5: Select BACT

To achieve the most effective NO_x control levels at DMW2, EDCC is proposing extended absorption with a SCR unit. EDCC is proposing a BACT limit of 5 ppm_v on a rolling 30-day average basis, exclusive of emissions related to SSM. This is equivalent to the lowest permitted limits found (based on application of Uhde EnviNO_x control technology). Additional BACT limits for this source include 100 ppm_v on a 3-hour average, inclusive of emissions related to SSM, and 6 ppm_v on a rolling 12-month average, inclusive of emissions related to SSM.

The concentrations for NO_x converted to mass rates are 33.78 lb/hr (3-hour average inclusive of SSM), 3.38 lb/hr (30-day rolling average excluding SSM), 26.35 lb/hr (30-day rolling average including SSM), and 17.76 tpy (rolling 12-month average). The corresponding production based limits are 0.64 lb/ton (3-hour average including SSM), 0.064 lb/ton (30-day rolling average excluding SSM), 0.5 lb/ton (30-day rolling average including SSM), and 0.078 lb/ton (rolling 12-month average including SSM).

EDCC also proposes a BACT limit of 0% for opacity.

CO_2e Emissions from the DM Weatherly Nitric Acid Plant No. 2

N_2O emissions from nitric acid manufacturing are a byproduct of the process stream and are therefore characterized as "industrial process" emissions. Ammonia oxidation is the source of

N_2O emissions from nitric acid production. The amount of N_2O formed depends on combustion conditions in the oxidizing unit, catalyst compositions, catalyst age, and burner design.

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

There are two basic types of nitric acid plants. They are single pressure and dual pressure. Common to North America, single pressure plants apply a single pressure throughout the reaction and absorption stages. The pressure in a single pressure plant can be low (at atmospheric pressure), Medium (400 to 800 kPa, or 4 to 8 atm), or high (800 to 1,000 kPa or 8 to 14 atm). Newer, small process units tend to use the high-pressure process, which helps to ensure efficient absorption. Dual pressure plants which were developed in Europe typically use low pressure for the reaction stage and high pressure for the absorption stage. The relatively low pressure in the ammonia oxidation stage helps to efficiently produce Nitric Oxide (NO) and extend the primary catalyst life. Compressing gases under high pressure during the absorption phase enhances that process as well. Dual pressure plants tend to use "medium pressures (about 4 atm) for ammonia conversion and high pressure (8 to 14 atm) for absorption. The pressure of the plants may have an impact on the effectiveness of some of the controls listed below. The amount of N_2O formed during the nitric acid production process depends on the combustion conditions (temperature and pressure), primary catalyst composition and age, and the burner design.

Nitric Acid Plants typically rely on three main types of N_2O control, and they are based on the location of the control within the production process. They are Primary, Secondary, and Tertiary.

Primary Controls

Primary controls reduce the amount of N_2O formed in the ammonia oxidation step. This can be accomplished by modifying the catalyst used in the oxidation process and/or modifying the operating conditions of the oxidation process. Primary controls suppress the formation of N_2O during the oxidation process. One control technique used is the extension of the NH_3 oxidation reactor, which extends the residence time from one to three seconds. Another primary control technique is to modify the ammonia oxidation gauze. This can be accomplished by utilizing an improved platinum catalyst or an alternative oxidation catalyst that is not platinum based.

Secondary Controls

Secondary controls reduce the N_2O upon formation in the ammonia oxidation process. Secondary control consists of an additional catalyst located immediately downstream of the ammonia oxidation catalyst. Placing this pelletized catalyst directly in the ammonia burner causes the N_2O to decompose to N_2 and O_2. The use of this control has shown no impact on ammonia conversion. The average lifetime of this catalyst is four years.

Tertiary Controls

Tertiary controls reduce N_2O by installing a catalytic reactor downstream of the ammonia oxidation reactor and either upstream or downstream of the tail gas expansion unit following ammonia oxidation. There are two main types of tertiary controls. They are catalytic reduction and catalytic decomposition.

Nonselective Catalytic Reduction (NSCR) is a common control technology for NO_x compounds within nitric acid facilities. Facilities that utilize NSCR have integrated the NSCR into the overall energy balance of the system. NSCR systems consume large quantities of hydrocarbons, such as natural gas, propane and butane to create the oxidation environment. The excess heat from the NSCR is used within the plant design. As such, existing nitric acid plants would not install NSCR systems unless the excess heat was integrated into the plant design. The NSCR reduces NO_x and inadvertently N_2O due to the extreme oxidation temperature and residence time.

Catalytic decomposition as a tertiary control can be high or low temperature, does not require any additional reducing agents, and does not form any undesirable byproducts from the reaction. A catalyst is used to drive the decomposition. The catalyst can be placed upstream or downstream of a Selective Catalytic Reduction (SCR) unit (depending on the design and selected catalyst) since it is stable in the presence of NO_x and ammonia. There are some types of N_2O abatement catalysts that have improved performance when NO_x is present in the exhaust gas, while other N_2O catalysts have improved performance when there is no or little NO_x.

Note that SCR could also be considered as an example of a tertiary control. SCR has shown to have a slight unintentional impact on N_2O emissions (+/- <5%). However, a SCR would not be installed specifically for N_2O abatement.

Step 2: Eliminate Technically Infeasible Options

Any control technologies that are not feasible should be identified and eliminated. Technical infeasibility can be demonstrated by clear physical, chemical, or other engineering principles which preclude the technology from being adaptable to this source. Due to their widespread application and use, all four of the N_2O control types listed in Step 1 are technically feasible for this Nitric Acid Plant.

However, although each technology is "technically feasible", secondary controls on a high pressure plant are not ideal and will not reduce N_2O to the levels achieved by a tertiary system. The pressure drop associated with the secondary catalyst bed directly following the platinum gauze can be significant on high pressure plants, thus negatively impacting the process and decreasing conversion efficiency and ultimate nitric acid formation. To avoid this excessive pressure drop, the secondary catalyst bed depth must be reduced, thus decreasing the residence time of the air passing through the catalyst and dramatically decreasing the N_2O removal efficiency. So although secondary control is technically feasible, the use of secondary control for this high pressure plant will not be a viable option based on the high level of N_2O destruction efficiency desired to meet BACT requirements.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

First Ranking: Tertiary Catalytic Reduction is the most effective N_2O control. Tertiary Catalytic Reduction consistently demonstrates greater than 90% reduction of N_2O emissions.

Second Ranking: Secondary Catalytic Reduction typically reduces up to 90% of the N_2O. However, based on the high pressure design of the EDCC NAP, secondary N_2O abatement would likely not exceed 70%.

Third Ranking: Primary reduction controls generally achieve an N_2O reduction efficiency of less than 70%.

Step 4: Evaluate Most Effective Controls and Document Results

The most effective control for N_2O in a high pressure Nitric Acid Plant is tertiary catalytic reduction. When compared to secondary catalytic reduction, tertiary catalytic reduction is more expensive. However, tertiary catalytic reduction on average has a reduction efficiency ten percent greater than that of secondary catalytic reduction.

Step 5: Select BACT

EDCC has chosen to use tertiary catalytic reduction as the BACT for the proposed Nitric Acid Plant. Tertiary catalytic reduction is the most expensive control technology of the evaluated technologies; however, it is also a proven control technology that provides the best available reduction. EDCC decided to use tertiary catalytic reduction as the selected control technology based on its superior N_2O reduction efficiency and the lack of pressure drop across the tertiary system compared to that of a secondary system. The equipment chosen by EDCC for the Nitric Acid plant is expected have an average N_2O control efficiency of 95% over the life of the primary gauze. Additionally, GHGs are significantly reduced by utilizing a portion of the reaction energy recovered in the heat exchanger train to reheat the tail gas to provide power for the air compressor by driving a hot gas expander.

The facility is proposing a 30 ppm_v (3-hr average) BACT limit for N_2O. The concentration for N_2O converted to an hourly mass rate is 20.6 lb/hr (3-hr average). The corresponding production based limits are 0.39 lb/ton (3-hour average) for N_2O. After reviewing the information submitted by the facility, the Department is assigning BACT limits for this source regarding the CO_2e emissions. The Department identified the Iowa Fertilizer Company as having additional BACT limits, and these limits will be assigned to EDCC.

The limits assigned are 98% destruction efficiency (DRE) for N_2O, 90.04 tons of N_2O per rolling 12-month period, and 27,911.28 tons of CO_2e per rolling 12 months of CO_2e.

A summary of the BACT limits for SN-59 can be found in the following table:

<table>
<tr><th colspan="5">BACT Analysis Summary</th></tr>
<tr><th>Source</th><th>Description</th><th>Pollutant</th><th>Control Technology</th><th>BACT Limit</th></tr>
<tr><td rowspan="3">SN-59</td><td rowspan="3">DM Weatherly Nitric Acid Plant # 2</td><td>Opacity</td><td rowspan="2">SCR with extended absorption, good and efficient operating practices</td><td>0%</td></tr>
<tr><td>NO_x</td><td>100 ppm_v (3-hr average including SSM)
0.64 lb/ton (3-hr average including SSM)
33.78 lb/hr (3-hr average including SSM)

5 ppm_v (Rolling 30-day average excluding SSM)
0.064 lb/ton (Rolling 30-day average excluding SSM)
3.38 lb/hr (Rolling 30-day average excluding SSM)

0.5 lb/ton of 100% Nitric Acid (Rolling 30-day average including SSM)
26.35 lb/hr (Rolling 30-day average including SSM)

6 ppm_v (Rolling 12 months including SSM)
17.76 tons per rolling 12 months (Including SSM)</td></tr>
<tr><td>GHG</td><td>Tertiary catalytic reduction</td><td>N_2O 30 ppm_v (3-hr average)
N_2O 0.39 lb/ton (3-hr average)
N_2O 20.6 lb/hr (3-hr average)
N_2O 98% destruction efficiency
N_2O 90.04 tons per rolling 12 months
CO_2e 27,911.28 tons per rolling 12 months</td></tr>
</table>

Ammonia Plant Primary Reformer (SN-49)

Nitrogen Oxides (NO_X)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of NO_x emissions from hydrogen reformers at both ammonia plants and located in the refinery industry. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Ammonia Plant Primary Reformer	SCR	October 2012	9 ppmv 0.0124 lb/MMBtu 30-day rolling average
RBLC ID: OK-0134	Pryor Chemical Company Pryor, OK Ammonia Plant Primary Reformer	Low NO_X Burners/ Good Combustion	February 2009	0.12 lb/MMBtu
RBLC ID: TX-0288	Air Liquide Freeport, TX Steam Methane Reformer	SCR	June 2001	8.5 lb/hr 0.030 lb/MMBtu 3-hour average
RBLC ID: LA-0211	Marathon Petroleum Garyville, LA Hydrogen Reformer Flue Gas Vent	SCR	December 2006	0.0125 lb/MMBtu annual average
RBLC ID: PA-0231	United Refinery Company Warren, PA Hydrogen Reformer Unit	Low NO_X Burners	October 2003	0.04 lb/MMBtu
RBLC ID: OH-0329	BP North America Toledo, OH Reformer Heater	Low NO_X Burners	August 2009	0.045 lb/MMBtu 40 ppm 24-hr rolling average

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
RBLC ID: CA-1121	Chevron Products Los Angeles, CA Heater	Low NO_X Burners/SCR	July 2003	5 ppmvd 3-hour average
RBLC ID: NM-0050	Navajo Refining Company Artesia, NM Steam Methane Reformer Heater	SCR	December 2007	0.0125 lb/MMBtu 3-hour rolling average

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for NO_X emissions at primary reformers, the following are feasible control options:

- Selective Catalytic Reduction (SCR)
- Low NO_X Burners and Flue Gas Recirculation

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective control technology for the reduction of NO_X emissions at primary reformers is Selective Catalytic Reduction. Typical control efficiencies range from 90% to 95%.

Step 4: Evaluate Most Effective Controls and Document Results

According to the RBLC/other information sources, the most effective NO_x control technology is an SCR unit. All but 3 entries in the RBLC specified low NO_x burners as meeting the BACT requirement for the control of NO_x emissions from natural gas-fired combustion devices.

The reformer permitted at the Chevron Plant (CA-1121) is not in operation in an ammonia manufacturing plant. The reformer at Chevron utilizes catalytic reforming, whereas, the reformer at EDCC will be a steam methane reformer. Therefore, the two reformers are not comparable. Note also that in the Iowa Fertilizer Plant permit, information states that only natural gas will be used as fuel to the reformer. At EDCC, the primary reformer will fire natural gas and purge gas from the ammonia manufacturing process. This purge gas contains up to 5% ammonia, which could be converted to NO_x in the combustion reaction. Considering that statement, the NO_x BACT limit proposed for SN-49, which is the same as that for the Iowa facility, could be considered more conservative.

Step 5: Select BACT

EDCC has selected an SCR unit as BACT for NO_X emissions at the ammonia plant primary reformer. EDCC proposes a BACT limit of 0.0124 lb NO_x/MMBtu per hour heat input at the primary reformer based on a 3-hour averaging period, and 44.75 tons per rolling 12-month period.

EDCC also proposes a BACT limit of 0% for opacity.

Carbon Monoxide (CO)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of CO emissions from reformers at ammonia plants as well as reformers located in the refinery industry. There were seven entries with listed control technologies for CO emissions from reformers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	CO Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Ammonia Plant Primary Reformer	Good Combustion Practices	October 2012	0.0194 lb/MMBtu
RBLC ID: LA-0236	CF Industries Donaldsonville, LA Ammonia Plant Primary Reformers	Good Combustion Practices	August 2009	0.05 lb/ton produced
RBLC ID: OK-0134	Pryor Chemical Company Pryor, OK Ammonia Plant Primary Reformer	Good Combustion Practices	February 2009	0.083 lb/MMBtu
RBLC ID: TX-0288	Air Liquide Freeport, TX Steam Methane Reformer	Good Combustion Practices	January 2005	0.03 lb/MMBtu
RBLC ID: LA-0211	Marathon Petroleum Garyville, LA Hydrogen Reformer Flue Gas Vent	Good Combustion Practices	December 2006	0.04 lb/MMBtu (30-day avg)

Reference	Facility Name/Location	Control Technology	Date Issued	CO Emission Limit
RBLC ID: PA-0231	United Refinery Company Warren, PA Hydrogen Reformer Unit	Good Combustion Practices	October 2003	0.09 lb/MMBtu
RBLC ID: OH-0329	BP North America Toledo, OH Reformer Heater	Good Combustion Practices	August 2009	0.04 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for CO emissions at primary reformers, good combustion practices was identified as the only feasible control option. Efficient combustion includes tuning of the burners within the reformer to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the stack. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion at the reformer is the only remaining feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion of the primary reformer is the only utilized and most effective for the control of CO emissions. All seven entries in the RBLC also identified good combustion practices as the only control for CO emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for CO emissions at the ammonia plant primary reformer. EDCC proposes a BACT limit of 0.0194 lb CO/MMBtu per hour heat input at the primary reformer, on a 3-hour average basis, and 70.02 tons per rolling 12-month period.

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of VOC emissions from reformers at ammonia plants as well as reformers located in the refinery industry. There were six entries with listed control technologies for VOC emissions from reformers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	VOC Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Ammonia Plant Primary Reformer	Good Combustion Practices	October 2012	0.0014 lb/MMBtu
RBLC ID: OK-0134	Pryor Chemical Company Pryor, OK Ammonia Plant Primary Reformer	Good Combustion Practices	February 2009	0.006 lb/MMBtu
RBLC ID: TX-0288	Air Liquide Freeport, TX Steam Methane Reformer	Good Combustion Practices	January 2005	0.006 lb/MMBtu
RBLC ID: LA-0211	Marathon Petroleum Garyville, LA Hydrogen Reformer Flue Gas Vent	Good Combustion Practices	December 2006	0.0015 lb/MMBtu
RBLC ID: PA-0231	United Refinery Company Warren, PA Hydrogen Reformer Unit	Good Combustion Practices	October 2003	0.003 lb/MMBtu
RBLC ID: OH-0329	BP North America Toledo, OH Reformer Heater	Good Combustion Practices	August 2009	0.005 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for VOC emissions at primary reformers, good combustion practices was identified as the only feasible control option. Efficient combustion includes tuning of the burners within the reformer to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the stack. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion at the reformer is the only remaining feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion of the primary reformer is the only utilized and most effective for the control of VOC emissions. All six entries in the RBLC also identified good combustion practices as the only control for VOC emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for VOC emissions at the ammonia plant primary reformer. EDCC proposes a BACT limit of 0.0014 lb VOC/MMBtu per hour heat input at the primary reformer, on a 3-hour average basis, and 5.05 tons per rolling 12-month period.

Sulfur Dioxide (SO_2)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of SO_2 emissions from reformers at ammonia plants as well as reformers located in the refinery industry. There were five entries for SO_2 emissions from reformers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	SO_2 Emission Limit
RBLC ID: OK-0134	Pryor Chemical Company Pryor, OK Ammonia Plant Primary Reformer	When firing pipeline natural gas, ≤ 5 grains sulfur/100 SCF	February 2009	0.2 lb/MMBtu (3-hour average)

Reference	Facility Name/Location	Control Technology	Date Issued	SO_2 Emission Limit
RBLC ID: TX-0288	Air Liquide Freeport, TX Steam Methane Reformer	Use low sulfur fuel, <5 grains sulfur/100 DSCF	January 2005	0.02 lb/hr
RBLC ID: LA-0211	Marathon Petroleum Garyville, LA Hydrogen Reformer Flue Gas Vent	Use low sulfur fuel	December 2006	25 ppmv (annual average)
RBLC ID: PA-0231	United Refinery Company Warren, PA Hydrogen Reformer Unit	Good Combustion Practices	October 2003	9.22 lb/hr (0.027 lb/MMBtu)
RBLC ID: OH-0329	BP North America Toledo, OH Reformer Heater	None	August 2009	0.04 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for SO_2 emissions at primary reformers, good combustion practices and the use of low sulfur fuel were identified as the only feasible control options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion and the use of low sulfur fuel at the reformer is the only feasible control option.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion and the use of low sulfur fuel are the only utilized and most effective control options for SO_2 emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion and the use of low sulfur fuel as BACT for the primary reformer. EDCC proposes a BACT limit of 0.00074 lb SO_2/MMBtu per hour heat input at the primary reformer, on a 3-hour average basis, and 0.44 tons per rolling 12-month period. This BACT limit will apply for all natural gas combustion SO_2 limits. This limit is based on the sulfur content of the natural gas supplied to the facility. The facility was provided information from their natural gas supplier that the natural gas supplied to EDCC will not contain any odorants. The annual BACT limit is based on a maximum of 50 ppb sulfur content after the fuel gas desulfurization unit.

El Dorado Chemical Company
Permit #: 0573-AOP-R16
AFIN: 70-00040

CO_2e Emissions from the Primary Reformer

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

The following have been proposed as potential CO_2 emission control technologies for the primary reformer.

- Carbon capture and sequestration
- Chemical scrubbing
- Energy efficiency design and operation

Carbon capture and sequestration (CCS) has the potential to reduce and potentially eliminate direct CO_2 emissions from the flue gas from the primary reformer. This method of control requires the capture, pressurization, transportation, and injection within the subsurface for geologic storage. A membrane-based CO_2 capture system would use permeable or semi-permeable materials to selectively separate CO_2 from the flue gas. Typical solvents for post-combustion capture include mono-ethanolamine. Industry-wide efforts to improve solvent reactivity, reduce thermal degradation, and most importantly reduce the energy consumed for solvent regeneration are in the research phase.

After capture, the CO_2 gas must be pressurized, transported and sequestered. Geologic formations such as oil and gas reservoirs, un-mineable coal seams and underground saline formations are potential operations for long-term storage. Beneficial re-use (e.g., enhanced oil recovery or carbonation) is a potential alternative to strict storage. Large-scale sources of CO_2 are imposed on this background of potential basins and reservoirs. With the continued exploration and growth in the oil and gas industry, it is expected that additional CO_2 capacity will be required to support this growth for enhanced oil recovery (EOR) and EOR will become a more common method of CO_2 beneficial reuse.

Amine scrubbing is a chemical scrubbing technology for CO_2 removal in the flue gas. Monoethanolamine is the predominant scrubbing solvent used for CO_2 removal. Currently, amine scrubbing is used on a limited basis primarily in the utility sector. Moreover, amine scrubbing is capital and energy intensive. There are no current installations of amine scrubbers on any ammonia production plants in the United States.

The following energy efficiency alternatives are considered such that the natural gas usage required to produce the equivalent amount of steam would be reduced without impacting the process. However, a reduction in natural gas usage is a direct correlation to CO_2 emissions from the primary reformer.

Burner tuning

The primary goal is to achieve the maximum efficiency of the burner(s), such that combustion efficiency is increased. Burner tuning is the first step in achieving combustion efficiency and may have a direct impact on the formation and generation of CO_2 by minimizing the unburned carbon in the flue gas.

Combustion control

Combustion efficiency can be monitored and controlled through feedback loops that monitor temperature and/or oxygen levels within the system. Theoretically, once the burner(s) is/are tuned within the ideal set points the combustion efficiency is controlled and monitored via these parameters. Consequently, facilities are able to maintain a more transparent and accurate understanding of the corresponding burner(s) performance.

High efficiency design

Convection section heat recovery can raise the overall thermal efficiency through generation of high pressure steam or through preheat of process streams. The recovery of heat through generation of high pressure steam, which can then be used in the plant to power steam turbine drives for compressors, pumps, and fans, could reduce the amount of supplemental fuel firing needed to generate the steam needed to power these drives.

Step 2: Eliminate Technically Infeasible Options

As part of the BACT analysis, the control technologies identified as part of Step 1 are reviewed for their technical feasibility. Both CCS and energy efficiency design would be considered to be technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Currently, the technically feasible CO_2 options for the primary reformer are CCS and potential implementation of energy efficiency measures including burner tuning, combustion control and high efficiency heat recovery.

Step 4: Evaluate Most Effective Controls and Document Results

Currently, the technically feasible CO_2 reduction options for the primary reformer that may be implemented are as follows:

- Combustion control
- CCS
- High efficiency heat recovery

CCS is being used in pilot-scale projects and is not currently in use in large-scale applications. There has been progress in the development of a proprietary solvent, which facilitates the absorption of the lower concentrations of CO_2 from the flue gas. However, implementation of CCS using this type of solvent is anticipated to result in higher capital and operating costs. In addition, the technology still remains unproven on a full-scale basis. Furthermore, there is not currently a nearby CO_2 storage reservoir, thus increasing the capital costs of pipeline construction and lifecycle costs associated with the maintenance and operability of the system. Additionally, where practicable when reviewing the technical feasibility of CCS, enhanced oil recovery has become a viable option.

However, information gathered from the National Piping Mapping System shows that currently there are no enhanced oil recovery lines or CO_2 lines to accept facility discharge. Although technically feasible, the distance to the closest point of CO_2 injection is greater than 100 miles from the facility. A CCS project would require the design and construction of a new pipeline system. Highlighted below are some major components of what comprises a pipeline construction project of this magnitude:

- A significant amount of capital and construction cost
- Multi-agency permits (rights-of-way, various local construction permits)
- Potential state line crossings
- A project schedule that can take several years to execute and be ready to accommodate the CO_2 from LSB's process.

Therefore, because the cost impact resulting from the direct (capital, construction, etc.) and indirect costs (multi-agency coordination, project schedule, etc.) would significantly impact the facility's economic competitiveness, CCS is not currently a viable BACT option for the primary reformer.

Although high efficiency heat recovery is technically feasible, there are several factors that preclude it from being implemented as BACT, including the following:

- The radiant section fuel firing would decrease
- The auxiliary boiler and convection section fuel firing would increase by a corresponding amount
- All of the burners would need to be replaced
- Combustion air preheater would need to be added

- Forced draft fan would be added
- Combustion air ducting would be added
- Stack gas temperature and overall thermal efficiency would not improve and it is expected that the amount of CO_2 emissions would not be reduced

Step 5: Select BACT

BACT for GHG control for the primary reformer is expected to incorporate elements of combustion control that reduce CO_2 emissions, yet do not impact the process. Prior to implementation, LSB will develop a work plan outlining the energy efficiency design elements. Once these final design elements are put into practice, LSB, where practicable will maintain a continuous record of set points that directly correlate to fuel usage and CO_2 emissions from the primary reformer.

The facility has proposed a BACT limit of 0.00022 lb/MMBtu for N_2O, 0.0022 lb/MMBtu for Methane, and 117 lb/MMBtu for CO_2. These rates equal 0.18 lb/hr for N_2O, 1.82 lb/hr for Methane, and 96,643.5 lb/hr for CO_2. All short-term limits are based on a 3-hour averaging period. The annual BACT limit for CO_2e is 423,714.2 tpy on a rolling 12-month basis.

A summary of the BACT limits for SN-49 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-49	Ammonia Plant Primary Reformer (824 MMBtu/hr natural gas-fired reformer with SCR)	Opacity	Combustion of natural gas and process off gas (purge gas), and good and efficient combustion practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.61 lb/hr (3-hr average) 0.44 tons per rolling 12 months
		VOC		0.0014 lb/MMBtu (3-hr average) 1.15 lb/hr (3-hr average) 5.05 tons per rolling 12 months
		CO		0.0194 lb/MMBtu (3-hr average) 15.99 lb/hr (3-hr average) 70.02 tons per rolling 12 months
		NO_x	SCR	0.0124 lb/MMBTU (3-hr average) 10.22 lb/hr (3-hr average) 44.75 tons per rolling 12 months
		GHG	Good operating practices	CO_2 117 lb/MMBTU (3-hr average) CH_4 0.0022 lb/MMBTU (3-hr average) N_2O 0.00022 lb/MMBTU (3-hr average) CO_2e 423,714.2 tons per rolling 12 months

Ammonia Plant Condensate Steam Stripper (SN-50)

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC was conducted to identify technologies currently in use for the control of VOC emissions from condensate steam strippers at ammonia plants. At this time, there is no listed control technology for the control of VOC emissions at an ammonia condensate steam stripper. In cases where an industrial process has removed VOC emissions from a process stream, they may choose to route the volatile gas to an incineration device. In the case of the proposed steam stripper at EDCC, the amount of volatile gas coming off of the unreacted steam is a low concentration and is therefore infeasible to route to combustion.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for VOC emissions at steam strippers at ammonia plants, there are no controls listed in the RBLC. In the case of the proposed steam stripper at EDCC, the amount of volatile gas coming off of the unreacted steam is a low concentration and is therefore infeasible to route to combustion.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

There is no feasible control for VOC emissions at the ammonia plant condensate steam stripper at EDCC.

Step 4: Evaluate Most Effective Controls and Document Results

There is no feasible control for VOC emissions at the ammonia plant condensate steam stripper at EDCC.

Step 5: Select BACT

EDCC has selected proper operation of the condensate steam stripper as BACT for VOC emissions at the ammonia plant. EDCC proposes a BACT limit of 0.1 lb VOC/ton of ammonia produced at the ammonia plant condensate steam stripper, and 5.83 lb/hr VOC, on a 24-hr average, and 25.55 tons per rolling 12-month period.

CO_2e Emissions from the Ammonia Plant Condensate Steam Stripper

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

The condensate flash tank is a non-combustion process; therefore CO_2 control technologies are currently limited to good operating practices and CCS. Good operating practice in the ammonia industry is considered to be downstream use of a byproduct, such as utilizing CO_2 from the condensate flash tank as part of urea production. However, LSB does not currently have a urea plant, where CO_2 can be "reused" as part of the process.

Step 2: Eliminate Technically Infeasible Options

As part of the BACT analysis, the control technologies identified as part of Step 1 are reviewed for their technical feasibility. A control technology is considered to be technically feasible if it has been previously installed and is in practice at a similar source and/or process operating successfully.

CCS is being used in pilot-scale projects and is not currently in use in large-scale applications. Although there continues to be the development of proprietary solvents which facilitates the absorption of CO_2, CCS technologies are not yet commercially available for process sources. Furthermore, there is not currently a nearby CO_2 storage reservoir to utilize for the CO_2 captured from the condensate flash tank. Additionally, there are no nearby industries that could utilize the CO_2 for carbonation. Therefore, CCS is considered to be technically infeasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Based on the existing and near-term facility infrastructure, there are no technically feasible control options for CO_2 control.

Step 4: Evaluate Most Effective Controls and Document Results

Because there are currently no technically feasible control options, this step of the BACT process is not required.

Step 5: Select BACT

The BACT limits for this source include 6.8 lb CO_2/ton of NH_3 production on a 24-hr average, 396.64 lb/hr CO_2 on a 24-hr average, and 1,737.4 tons of CO_2e per rolling 12 months.

A summary of the BACT limits for SN-50 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-50	Ammonia Plant Condensate Steam Stripper	VOC	Good and efficient operating practices	0.1 lb/ton of NH_3 produced (24-hr average) 5.83 lb/hr (24-hr average) 25.55 tons per rolling 12 months
		GHG		CO_2 6.8 lb/ton of Ammonia production (24-hr average) CO_2 396.64 lb/hr (24-hr average) CO_2e 1,737.4 tons per rolling 12 months

Ammonia Plant CO_2 Regenerator (SN-51)

Carbon Monoxide (CO)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of CO emissions from CO_2 regenerators at ammonia plants. There was one entry with listed control technologies for CO emissions from regenerators. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	CO Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Ammonia Plant Primary Reformer	Good Operational Practices	October 2012	0.02 lb/ton ammonia produced

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for CO emissions at CO_2 regenerators, good operational practices was identified as the only feasible control option. This includes proper tuning of process control systems to ensure that CO_2 removal efficiencies and MDEA levels are allowing for proper emission minimization.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper operation at the CO_2 regenerator is the only feasible control option. As stated above, this would consist of conducting preventive steps to ensure that the proper column operation is maintained ensuring CO_2 removal efficiency and thus CO minimization.

Step 4: Evaluate Most Effective Controls and Document Results

Proper and efficiency operation of the CO_2 regenerator is the most effective control measure.

Step 5: Select BACT

EDCC has selected good and efficient operation as BACT for CO emissions at the CO_2 regenerator at the ammonia plant. The BACT limits for this source include 0.02 lb CO/ton of NH_3 production on a 3-hr average, 1.17 lb/hr CO on a 3-hr average, and 5.11 tons of CO per rolling 12 months.

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of VOC emissions from CO_2 regenerators at ammonia plants. There was one entry with listed control technologies for VOC emissions from regenerators. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	VOC Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Ammonia Plant Primary Reformer	Good Operational Practices	October 2012	0.106 lb/ton ammonia produced

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for VOC emissions at CO_2 regenerators, good operational practices was identified as the only feasible control option. This includes proper tuning of process control systems to ensure that CO_2 removal efficiencies and MDEA levels are allowing for proper emission minimization.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper operation at the CO_2 regenerator is the only feasible control option. As stated above, this would consist of conducting preventive steps to ensure that the proper column operation is maintained ensuring CO_2 removal efficiency and thus VOC minimization.

Step 4: Evaluate Most Effective Controls and Document Results

Proper and efficiency operation of the CO_2 regenerator is the most effective control measure.

Step 5: Select BACT

EDCC has selected good and efficient operation as BACT for VOC emissions at the CO_2 regenerator at the ammonia plant. The BACT limits for this source include 0.106 lb VOC/ton of NH_3 production on a 3-hr average, 33.64 lb/hr VOC on a 3-hr average, and 147.35 tons of VOC per rolling 12 months.

CO_2e Emissions from the Ammonia Plant CO_2 Regenerator

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

The regenerator is a noncombustible process; therefore CO_2 control technologies are currently limited to good operating practices and CCS. Good operating practices in the ammonia industry are considered to be the downstream use of a by-product, such as utilizing CO_2 from the regenerator as part of urea production. However, LSB does not currently have a urea plant where CO_2 can be "reused" as part of the process.

Step 2: Eliminate Technically Infeasible Options

As part of the BACT analysis, the control technologies identified as part of Step 1 are reviewed for their technical feasibility. A control technology is considered to be technically feasible if it has been previously installed and is in practice at a similar source and/or process and is operating successfully.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Based on the existing and near-term facility infrastructure, there are no technically feasible control options for CO_2 control.

Step 4: Evaluate Most Effective Controls and Document Results

Because there are currently no technically feasible control options, this step of the BACT process is not required.

Step 5: Select BACT

The BACT limits for this source include 2,507.5 lb CO_2/ton of NH_3 production on a 3-hr average, 146,262.6 lb/hr CO_2 on a 3-hr average, and 640,669.2 tons of CO_2/CO_2e per rolling 12 months.

A summary of the BACT limits for SN-51 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-51	Ammonia Plant CO_2 Regenerator	VOC	Good and efficient operating practices	0.106 lb/ton of NH_3 produced (3-hr average) 33.64 lb/hr (3-hr average) 147.35 tons per rolling 12 months
		CO		0.02 lb/ton of NH_3 produced (3-hr average) 1.17 lb/hr (3-hr average) 5.11 tons per rolling 12 months
		GHG		CO_2 2,507.5 lb/ton of NH_3 produced (3-hr average) 146,262.6 lb/hr CO_2 CO_2/CO_2e 640,669.2 tons per rolling 12 months

Ammonia Plant Ammonia Vent Flare (SN-53)

Nitrogen Oxides (NO_x)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include NH_3 and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of NH_3 and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly NH_3 and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including NO_x.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of NH_3 and CH_4 emissions that are only released over short periods of time (i.e., during a synthesis loop depressurization for shut-down or maintenance or during an emergency), the flare is an effective control. Additionally, during the periods when there are no depressurization related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control emissions at the Ammonia Plant Ammonia Vent. The system will significantly reduce the NH_3 and CH_4 emissions that would otherwise be emitted from the source. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC proposes a BACT limit of 792.1 lb/hr of NO_x emissions. Annual emissions shall not exceed 6.9 ton/yr.

EDCC is proposing a BACT limit for opacity of 0%.

Carbon Monoxide (CO)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include NH_3 and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of NH_3 and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly NH_3 and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including CO.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of NH_3 and CH_4 emissions that are only released over short periods of time (i.e., during a synthesis loop depressurization for shut-down or maintenance or during an emergency), the flare is an effective control. Additionally, during the periods when there are no depressurization related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control emissions at the Ammonia Plant Ammonia Vent. The system will significantly reduce the NH_3 and CH_4 emissions that would otherwise be emitted from the source. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC proposes a BACT limit of 0.1 lb/hr of CO emissions. Annual emissions shall not exceed 0.4 ton/yr.

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include NH_3 and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of NH_3 and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly NH_3 and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including VOC.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of NH_3 and CH_4 emissions that are only released over short periods of time (i.e., during a synthesis loop depressurization for shut-down or maintenance or during an emergency), the flare is an effective control. Additionally, during the periods when there are no depressurization related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control emissions at the Ammonia Plant Ammonia Vent. The system will significantly reduce the NH_3 and CH_4 emissions that would otherwise be emitted from the source. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC proposes a BACT limit of 0.1 lb/hr of VOC emissions. Annual emissions shall not exceed 0.1 ton/yr.

Sulfur Dioxide (SO_2)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include NH_3 and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of NH_3 and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly NH_3 and CH4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including SO_2.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of NH_3 and CH_4 emissions that are only released over short periods of time (i.e., during a synthesis loop depressurization for shut-down or maintenance or during an emergency), the flare is an effective control. Additionally, during the periods when there are no depressurization related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control emissions at the Ammonia Plant Ammonia Vent. The system will significantly reduce the NH_3 and CH_4 emissions that would otherwise be emitted from the source. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC proposes a BACT limit of 0.1 lb/hr of SO_2 emissions. Annual emissions shall not exceed 0.1 ton/yr.

A summary of the BACT limits for SN-53 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-53	Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)	Opacity	Combustion of Natural gas and Good Combustion Practice	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) from pilot 0.00077 lb/hr (3-hr average) 0.0034 tons per rolling 12 months
		VOC		0.0054 lb/MMBtu (3-hr average) from pilot 0.0057 lb/hr (3-hr average) 0.025 tons per rolling 12 months
		CO		0.082 lb/MMBtu (3-hr average) from pilot 0.087 lb/hr (3-hr average) 0.38 tons per rolling 12 months
		NO_x		0.098 lb/MMBtu (3-hr average) from pilot 792.03 lb/hr (3-hr average based on 0.5% conversion of NH_3 to NO_x 6.9 tons per rolling 12 months
		GHG		CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 719.87 tons per rolling 12 months

El Dorado Chemical Company
Permit #: 0573-AOP-R16
AFIN: 70-00040

Ammonia Plant Startup Heater (SN-54)

Nitrogen Oxides (NO_x)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of NO_x emissions from heaters across all process types. There were seven entries with listed control technologies for NO_x emissions from small (<100 MMBtu/hr) heaters. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA 110.12 MMBtu/hr Startup Heater	Good Combustion Practices	October 2012	0.119 lb/MMBtu
RBLC ID: LA-0231	Lake Charles Cogeneration Lake Charles, LA 35 MMBtu/hr Startup Preheater 56.9 MMBtu/hr Startup Heater	Good Combustion Practices	June 2009	0.096 lb/MMBtu
RBLC ID: LA-0262	Cornerstone Chemical Jefferson Par., La. 61 MMBtu/hr Startup Heater	Good Engineering Practice	October 2012	0.17 lb/MMBtu
RBLC ID: CA-1212	City of Palmdale Hybrid Power Project 40 MMBtu/hr Auxiliary Heater	None	February 2013	9 ppm
RBLC ID: CA-1211	Pacific Gas & Elec. Colusa Generating Station 10 MMBtu/hr Heater	None	March 2011	30 ppm
RBLC ID: CA-1191	City of Victorville Hybrid Power Project San Bernardino, CA 40 MMBtu/hr Heater	None	March 2010	9 ppm

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
RBLC ID: ID-0017	Southeast Idaho Energy Power, ID 25 MMBtu/hr Heater	Good Combustion Practices	February 2009	None

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search, good combustion and engineering practices is the only control option utilized in the control of NO_x emissions from process heaters. Efficient combustion includes maintaining the burners within the heater to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the unit. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion at the heater is the only feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion of the startup heater is the only utilized and most effective for the control of NO_x emissions. All seven entries in the RBLC also identified good combustion practices as the only control for NO_x emissions.

Step 5: Select BACT

EDCC has selected the use of low-NO_x burners and good and efficient combustion as BACT for NO_x emissions at the startup heater. The BACT limits for this source include 0.06 lb NO_x/MMBtu per hour heat input at the startup heater on a 3-hr average, 2.28 lb/hr NO_x on a 3-hr average, and 0.57 tons of NO_x per rolling 12 months.

EDCC is proposing a BACT limit for opacity of 0%.

Carbon Monoxide (CO)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of CO emissions from heaters across all process types. There were six entries with listed control technologies for CO emissions from small (<100 MMBtu/hr) heaters. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	CO Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA 110.12 MMBtu/hr Startup Heater	Good Combustion Practices	October 2012	0.0194 lb/MMBtu
RBLC ID: CA-1212	City of Palmdale Hybrid Power Project 40 MMBtu/hr Auxiliary Heater	None	February 2013	50 ppm
RBLC ID: CA-1211	Pacific Gas & Elec. Colusa Generating Station 10 MMBtu/hr Heater	None	March 2011	100 ppm
RBLC ID: CA-1191	City of Victorville Hybrid Power Project San Bernardino, CA 40 MMBtu/hr Heater	None	March 2010	50 ppm
RBLC ID: LA-0231	Lake Charles Cogeneration Lake Charles, LA 35 MMBtu/hr Startup Preheater 56.9 MMBtu/hr Startup Heater	Good Combustion Practices	June 2009	0.081 lb/MMBtu
RBLC ID: ID-0017	Southeast Idaho Energy Power, ID 25 MMBtu/hr Heater	Good Combustion Practices	February 2009	None

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search, good combustion and engineering practices is the only control option utilized in the control of CO emissions from process heaters. Efficient combustion includes maintaining the burners within the heater to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the unit. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion at the startup heater is the only feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion of the startup heater is the only utilized and most effective for the control of CO emissions. All six entries in the RBLC also identified good combustion practices as the only control for CO emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for CO emissions at the startup heater. The BACT limits for these sources include 0.01 lb CO/MMBtu per hour heat input at the heater on a 3-hr average, 0.38 lb/hr CO on a 3-hr average, and 0.10 tons of CO per rolling 12 months.

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of VOC emissions from heaters across all process types. There were ten entries with listed control technologies for VOC emissions from small (<100 MMBtu/hr) boilers/heaters. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	VOC Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Startup Heater	Good Combustion Practices	October 2012	0.0014 lb/MMBtu
RBLC ID: CA-1211	Pacific Gas & Elec. Colusa Generating Station 10 MMBtu/hr Heater	None	March 2011	0.0027 lb/MMBtu
FL-0335	Klauser Holding Suwannee, FL 46 MMBtu/hr Boiler	Good Combustion Practices	September 2012	0.0030 lb/MMBtu
NJ-0079	CPV Shore Middlesex, NJ 91.6 MMBtu/hr Boiler	Use of Natural Gas	April 2013	0.0015 lb/MMBtu
OH-0350	Republic Steel Lorain, OH 65 MMBtu/hr Boiler	Proper Burner Design and Good Combustion Practices	July 2012	0.0054 lb/MMBtu
SC-0113	Pyramax Ceramics Allendale, SC 5 MMBtu/hr Boilers	Good Combustion Practices Use of Natural Gas and Propane	February 2012	None
LA-0246	Valero Refining St. Charles, LA 99 MMBtu/hr Boiler	Good Combustion Practices and Use of Gaseous Fuels	December 2010	0.0054 lb/MMBtu

Reference	Facility Name/Location	Control Technology	Date Issued	VOC Emission Limit
NV-0050	MGM Mirage Las Vegas, NV 41.64 MMBtu/hr Boilers 4.2 MMBtu/hr Boilers	Use of Natural Gas and Good Combustion Practices	November 2009	0.0024 lb/MMBtu 0.0048 lb/MMBtu
NV-0049	Harrah's Las Vegas, NV 8.4 MMBtu/hr Boiler 14.34 MMBtu/hr Boiler 16.8 MMBtu/hr Boiler 31.4 MMBtu/hr Boiler	Operate Per Manufacturer Specifications	August 2009	All 0.0054 lb/MMBtu
RBLC ID: LA-0231	Lake Charles Cogeneration Lake Charles, LA 35 MMBtu/hr Startup Preheater 56.9 MMBtu/hr Startup Heater	Good Combustion Practices	June 2009	None

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for VOC emissions from process heaters, good combustion practices was identified as the only feasible control option. Efficient combustion includes tuning of the burners within the heater to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the stack. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion in the heaters is the only remaining feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion in the heaters is the only utilized and most effective for the control of VOC emissions. All three entries in the RBLC also identified good combustion practices as the only control for VOC emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for VOC emissions at the ammonia plant start-up heater. The BACT limits for these sources include 0.002 lb VOC/MMBtu per hour heat input at the startup heater on a 3-hr average, 0.08 lb/hr VOC on a 3-hr average, and 0.019 tons of VOC per rolling 12 months.

Sulfur Dioxide (SO_2)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A four year search of the RBLC was conducted to identify technologies currently in use for the control of SO_2 emissions from heaters across all process types. There were eight entries with listed control technologies for SO_2 emissions from small (<100 MMBtu/hr) boilers/heaters. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	SO_2 Emission Limit
FL-0335	Klauser Holding Suwannee, FL 46 MMBtu/hr Boiler	Fuel Monitoring	September 2012	2 gr of sulfur/dscf
NJ-0079	CPV Shore Middlesex, NJ 91.6 MMBtu/hr Boiler	Use of Natural Gas	April 2013	0.002 lb/MMBtu
OH-0350	Republic Steel Lorain, OH 65 MMBtu/hr Boiler	None	July 2012	0.6 lb/MMSCF
SC-0113	Pyramax Ceramics Allendale, SC 5 MMBtu/hr Boilers	Use of Natural Gas	February 2012	None
LA-0246	Valero Refining St. Charles, LA 99 MMBtu/hr Boiler	Use of Natural or Refinery Gas with annual average H_2S content <100ppv	December 2010	0.025 lb/MMBtu

Reference	Facility Name/Location	Control Technology	Date Issued	SO_2 Emission Limit
NV-0050	MGM Mirage Las Vegas, NV 41.64 MMBtu/hr Boilers 4.2 MMBtu/hr Boilers	Use of Natural Gas and Good Combustion Practices	November 2009	0.0007 lb/MMBtu 0.0024 lb/MMBtu
NV-0049	Harrah's Las Vegas, NV 8.4 MMBtu/hr Boiler 14.34 MMBtu/hr Boiler 16.8 MMBtu/hr Boiler 31.4 MMBtu/hr Boiler	Use of Natural Gas and Good Combustion Practices	August 2009	0.0006 lb/MMBtu 0.0006 lb/MMBtu 0.0042 lb/MMBtu 0.0006 lb/MMBtu
LA-0231	Lake Charles Cogeneration Lake Charles, LA 56.9 MMBtu/hr Startup Heaters 35 MMBtu/hr Startup Preheaters	Use of Natural	June 2009	0.0006 lb/MMBtu 0.0006 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for SO_2 emissions at process heaters, good combustion practices and the use of low sulfur natural gas were identified as the only feasible control options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion and the use of low sulfur natural gas at the startup heater is the only feasible control option.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion and the use of low sulfur natural gas are the only utilized and most effective control options for SO_2 emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion and the use of low sulfur fuel as BACT for the startup heater. The BACT limits for these sources include 0.00074 lb SO_2/MMBtu per hour heat input at the startup heater on a 3-hr average, 0.028 lb/hr SO_2 on a 3-hr average, and 0.0070 tons of SO_2 per rolling 12 months.

CO_2e Emissions from the Ammonia Plant Startup Heater

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

The following have been proposed as potential CO_2 emission control technologies for the start-up heater:

- Carbon capture and sequestration
- Energy efficiency design and operation
- Alternative fuels.

Alternative Fuels

The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Currently, pure biomass fuels include animal meal, landfill gas, sawdust, waste wood products, and sewage sludge.

Step 2: Eliminate Technically Infeasible Options

As part of the BACT analysis, the control technologies identified as part of Step 1 are reviewed for their technical feasibility. A control technology is considered to be technically feasible if it has been previously installed and is in practice at a similar source and/or process and is operating successfully.

Carbon Capture and Sequestration

The technical infeasibility of CCS relative to combustion sources and the EDCC site has been previously described above. Therefore, it is not described again within this section.

Alternative Fuels

It is anticipated that the start-up heater will utilize natural gas as fuel. Currently, natural gas is the lowest GHG-emitting fossil fuel that could be used to provide the required steam production at the facility. In addition, natural gas is the feedstock for the ammonia process. As a result, natural gas as a low-GHG emitting fossil fuel and readily available process feedstock within the facility essentially renders alternative fuels technically infeasible for the start-up heater.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The technically feasible CO_2 option for the start-up heater is to fire only natural gas. The most recent RBLC entry identified for CO_2 has a BACT limit at 117 lb CO_2/MMBtu.

Step 4: Evaluate Most Effective Controls and Document Results

The technically feasible CO_2 reduction option for the start-up heater that may be implemented to achieve a BACT emission rate of 117 lb CO_2/MMBtu is firing only natural gas. Based on the design specifications developed for the start-up heater, it is expected that the CO_2 emissions for this unit will be consistent with the aforementioned BACT limit and therefore it is not necessary to further evaluate the environmental, energy or economic impacts of the technology.

Step 5: Select BACT

In summary, BACT for GHG control for the start-up heater is anticipated to include firing only natural gas and inherent design specifications to meet the aforementioned limit. CO_2 emissions from the start-up heater may not exceed 117 lb MMBtu/hr based on three 1-hour stationary source testing runs utilizing USEPA Method 3A. Methane BACT limits for the start-up heater may not exceed 0.0022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 18. Also, the N_2O emissions from the start-up heater may not exceed 0.00022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 320. In addition, the total CO_2e emissions of 1,115.3 tons per 12-month rolling averaging period shall not be exceeded.

A summary of the BACT limits for SN-54 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
54	Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)	Opacity	Combustion of Natural gas and Good Combustion Practice	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.03 lb/hr (3-hr average) 0.007 tons per rolling 12 months
		VOC		0.002 lb/MMBtu (3-hr average) 0.19 lb/hr (3-hr average) 0.048 tons per rolling 12 months
		CO		0.01 lb/MMBtu (3-hr average) 0.76 lb/hr (3-hr average) 0.19 tons per rolling 12 months
		NO_x	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.06 lb/MMBtu (3-hr average) 2.28 lb/hr (3-hr average) 0.57 tons per rolling 12 months
		GHG	Good operating practices	CO_2 117 lb/MMBtu CH_4 0.0022 lb/MMBtu N_2O 0.00022 lb/MMBtu CO_2e 1,115.31 tons per rolling 12 months

Ammonia Plant Process SSM Flare (SN-56) & Ammonia Storage Flare (SN-57)

Nitrogen Oxides (NO_x)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use for the control of NO_x emissions from ammonia plant vents. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of CO, CO_2, NH_3, and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly CO, CO_2, NH_3, and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including NO_X.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of CO, CO_2, NH_3, and CH_4 emissions that are only released over short periods of time; i.e., during /startups, shutdowns, and as otherwise needed for maintenance purposes (SSM), the flare is an effective control. Additionally, during the periods when there are no SSM related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control SSM related emissions at the Ammonia Plant and for Ammonia Storage. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC has proposed NO_X emissions for SN-56 and SN-57 of 0.1 and 10.1 lb/hr, respectively. Annual emissions for SN-56 and SN-57 shall not exceed 0.5 ton/yr and 43.9 ton/yr, respectively.

EDCC is proposing a BACT limit for opacity of 0%.

Sulfur Dioxide (SO_2)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include CO, CO_2, NH_3, and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of CO, CO_2, NH_3, and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly CO, CO_2, NH_3, and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including SO_2.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of CO, CO_2, NH_3, and CH_4 emissions that are only released over short periods of time; i.e., during /startups, shutdowns, and as otherwise needed for maintenance purposes (SSM), the flare is an effective control. Additionally, during the periods when there are no SSM related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control SSM related emissions at the Ammonia Plant and for Ammonia Storage. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC has proposed SO_2 emissions for SN-56 and SN-57 of 0.1 and 0.1 lb/hr, respectively. Annual emissions for SN-56 and SN-57 shall not exceed 0.1 ton/yr and 0.1 ton/yr, respectively.

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include CO, CO_2, NH_3, and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of CO, CO_2, NH_3, and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly CO, CO_2, NH_3, and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including VOC.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of CO, CO_2, NH_3, and CH_4 emissions that are only released over short periods of time; i.e., during /startups, shutdowns, and as otherwise needed for maintenance purposes (SSM), the flare is an effective control. Additionally, during the periods when there are no SSM related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control SSM related emissions at the Ammonia Plant and for Ammonia Storage. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC has proposed VOC emissions for SN-56 and SN-57 of 0.1 and 0.1 lb/hr, respectively. Annual emissions for SN-56 and SN-57 shall not exceed 0.1 ton/yr and 0.1 ton/yr, respectively.

Carbon Monoxide (CO)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A search of the RBLC and other published sources was conducted to identify technologies currently in use to control emissions from ammonia plant vents. Process gas emissions from these vents include CO, CO_2, NH_3, and CH_4. There were no entries with listed control technologies for emissions from ammonia plant vents in the RBLC. In cases of high levels of CO, CO_2, NH_3, and CH_4 concentrations in a waste gas, the primary solution is to flare the waste gas.

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for process gas vents, the two primary options are waste gas flares and the use of no controls. In the case of the ammonia plant vents at EDCC, both are feasible options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The most effective option for reducing high levels of NH_3 and CH_4 emissions is the use of a waste gas flare. In the case of EDCC, the components of the waste gas stream are predominantly CO, CO_2, NH_3, and CH_4. Therefore, the byproducts are CO_2 and water along with any combustion byproducts, including CO.

Step 4: Evaluate Most Effective Controls and Document Results

Due to the high levels of CO, CO_2, NH_3, and CH_4 emissions that are only released over short periods of time; i.e., during /startups, shutdowns, and as otherwise needed for maintenance purposes (SSM), the flare is an effective control. Additionally, during the periods when there are no SSM related releases, the flare is a minimal contributor to total emissions and does not require a significant amount of continuous maintenance.

Step 5: Select BACT

EDCC has selected a waste gas flare as BACT to control SSM related emissions at the Ammonia Plant and for Ammonia Storage. Due to the sporadic nature of flaring operations, a production-based BACT emission limit is not feasible. EDCC has proposed CO emissions for SN-56 and SN-57 of 156.1 and 0.1 lb/hr, respectively. Annual emissions for SN-56 and SN-57 shall not exceed 39.4 ton/yr and 0.1 ton/yr, respectively.

A summary of the BACT limits for SN-56 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-56	Ammonia Plant Process SSM Flare	Opacity	Combustion of Natural gas and Good Combustion Practice	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.00070 lb/hr (3-hr average) 0.0031 tons per rolling 12 months
		VOC		0.0054 lb/MMBtu (3-hr average) 0.0051 lb/hr (3-hr average) 0.023 tons per rolling 12 months
		CO		0.082 lb/MMBtu (3-hr average) from pilot 156.10 lb/hr (3-hr average based on 98% control of process gas 39.36 tons per rolling 12 months
		NO_x		0.098 lb/MMBtu (3-hr average) 0.093 lb/hr (3-hr average) 0.41 tons per rolling 12 months
		GHG		CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 5,179.8 tons per rolling 12 months

A summary of the BACT limits for SN-57 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-57	Ammonia Storage Flare	Opacity	Combustion of natural gas, and good and efficient operating practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.00015 lb/hr (3-hr average) 0.00056 tons per rolling 12 months
		VOC		0.0054 lb/MMBtu (3-hr average) 0.0011 lb/hr (3-hr average) 0.0041 tons per rolling 12 months
		CO		0.082 lb/MMBtu (3-hr average) 0.017 lb/hr (3-hr average) 0.063 tons per rolling 12 months
		NO_x		0.098 lb/MMBtu (3-hr average) from pilot 10.02 lb/hr (3-hr average based on 0.5% conversion of NH_3 to NO_x) 43.88 tons per rolling 12 months
		GHG		CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 89.99 tons per rolling 12 months

El Dorado Chemical Company
Permit #: 0573-AOP-R16
AFIN: 70-00040

Start-up Boiler (SN-61)

Nitrogen Oxides (NO_x)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A four year search of the RBLC was conducted to identify technologies currently in use for the control of NO_x emissions from boilers across all process types. There were eight entries with listed control technologies for NO_x emissions from natural gas-fired boilers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	NO_x Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Auxiliary Boiler	Low NO_x Burner	October 2012	0.0125 lb/MMBtu
RBLC ID: CA-1212	City of Palmdale Hybrid Power Project Auxiliary Boiler	None	February 2013	9 ppm
RBLC ID: CA-1206	APMC Stockton Stockton Cogen Auxiliary Boiler	None	September 2011	7 ppm 0.0085 lb/MMBtu
RBLC ID: OH-0336	Campbell Soup Co. Henry, OH Natural Gas Boilers	None	December 2010	0.04 lb/MMBtu
RBLC ID: MI-0389	Consumers Energy Karn Complex 220 MMBtu/hr Boiler	Low NO_x Burner	December 2009	0.018 lb/MMBtu 30-day rolling average
RBLC ID: NV-0050	MGM Mirage Clark Co., NV 42 MMBtu/hr Boilers (3)	Low NO_x Burner	November 2009	0.011 lb/MMBtu
RBLC ID: OH-0310	American Municipal Power Meigs Co., OH 150 MMBtu/hr Boiler	None	October 2009	0.14 lb/MMBtu
RBLC ID: NV-0049	Harrah's Operating Co.	Low NO_x Burner	August 2009	0.03 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search, ultra low NO_x burners or low NO_x burners, combined with good combustion and engineering practices, are the only control options utilized in the control of NO_x emissions from process boilers. Efficient combustion includes maintaining the burners within the boiler to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the unit. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

While the ultra low-NO_x burners available for the proposed startup boiler at EDCC provide increased NO_x reduction (i.e., capable of achieving a 9 ppm NO_x emission rate), their associated turndown rate is low (i.e., 4:1) compared to the low NO_x combustion efficient burners with flue gas recirculation proposed for EDCC's Start-Up Boiler, which has a turndown rate of 10:1. The turndown rate represents the maximum firing rate of the burners compared to the lowest controllable firing rate at which the boiler can operate. A higher turndown rate indicates greater combustion control under a wider range of operating conditions. This translates to better emission control as the firing rate at the boiler is increased/decreased to respond to variable plant startup conditions. The startup boiler, as intended for operation at EDCC, must be able to vary its firing rate over a broader range to respond to changing plant startup related conditions. Because the ultra low NO_x burners cannot be adjusted efficiently during low firing rate conditions, the ultra low NO_x burners are not considered technically feasible for the operational application at EDCC.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Use of low NO_x burners with flue gas recirculation at the boiler is the only feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Flue gas recirculation and low NO_x burner are the most effective controls for NO_x emissions at the startup boiler.

Step 5: Select BACT

EDCC has selected low NO_x, combustion efficient burners with flue gas recirculation as BACT for NO_x emissions at the startup boiler. The BACT limits for this source include 0.018 lb NO_x/MMBtu per hour heat input at the startup boiler on a 3-hr average, 4.32 lb/hr NO_x on a 3-hr average, and under Operating Scenario 1, 18.92 tons of NO_x per rolling 12 months. Under Operating Scenario 2, the annual limit will reduce to 5.68 tons of NO_x per rolling 12 months. The facility proposed two (2) operating scenarios for this boiler. One operating scenario was listed with the boiler operating at maximum capacity annually, and the other as a high turndown rate (10:1) boiler. The facility based their BACT analysis on operating the boiler with a high turndown rate, and chose limits based on this fact. Therefore, the other operating scenario is not feasible with a high turndown rate boiler. Not operating the boiler at a high turndown rate would constituent a change in the method of operation for the unit.

EDCC is proposing a BACT limit for opacity of 0%.

Carbon Monoxide (CO)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A four year search of the RBLC was conducted to identify technologies currently in use for the control of CO emissions from boilers across all process types. There were five entries with listed control technologies for CO emissions from natural gas-fired boilers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	CO Emission Limit
RBLC ID: CA-1212	City of Palmdale Hybrid Power Project Auxiliary Boiler	None	February 2013	50 ppm
RBLC ID: OH-0336	Campbell Soup Co. Henry, OH Natural Gas Boilers	None	December 2010	0.075 lb/MMBtu
RBLC ID: MI-0389	Consumers Energy Karn Complex 220 MMBtu/hr Boiler	Good Combustion Practices	December 2009	0.035 lb/MMBtu
RBLC ID: NV-0050	MGM Mirage Clark Co., NV	Good Combustion Practices	November 2009	0.019 lb/MMBtu
RBLC ID: OH-0310	American Municipal Power Meigs Co., OH 150 MMBtu/hr Boiler	None	October 2009	0.084 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search, good combustion and engineering practices is the only control option utilized in the control of CO emissions from process boilers. Efficient combustion includes maintaining the burners within the boiler to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the unit. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion at the startup boiler is the only feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion of the startup boiler is the only utilized and most effective for the control of CO emissions. All five entries in the RBLC also identified good combustion practices as the only control for CO emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for CO emissions at the startup boiler. The BACT limits for this source include 0.037 lb CO/MMBtu per hour heat input at the boiler on a 3-hr average basis, or 50 ppm_{vd}, 8.88 lb/hr CO on a 3-hr average, and under Operating Scenario 1, 38.89 tons of CO per rolling 12 months. Under Operating Scenario 2, the annual limit will be reduced to 11.67 tons of CO per rolling 12 months.

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A four year search of the RBLC was conducted to identify technologies currently in use for the control of VOC emissions from boilers across all process types. There were six entries with listed control technologies for VOC emissions from natural gas-fired boilers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	VOC Emission Limit
RBLC ID: IA-0105	Iowa Fertilizer Company Wever, IA Auxiliary Boiler	Good Combustion Practices	October 2012	0.0014 lb/MMBtu
RBLC ID: OH-0336	Campbell Soup Co. Henry, OH Natural Gas Boilers	None	December 2010	0.0054 lb/MMBtu
RBLC ID: MI-0389	Consumers Energy Karn Complex 220 MMBtu/hr Boiler	Good Combustion Practices	December 2009	0.0013 lb/MMBtu

Reference	Facility Name/Location	Control Technology	Date Issued	VOC Emission Limit
RBLC ID: NV-0050	MGM Mirage Clark Co., NV 42 MMBtu/hr Boilers (3)	Good Combustion Practices	November 2009	0.0024 lb/MMBtu
RBLC ID: OH-0310	American Municipal Power Meigs Co., OH 150 MMBtu/hr Boiler	None	October 2009	0.0055 lb/MMBtu
RBLC ID: NV-0049	Harrah's Operating Co.	None	August 2009	0.0054 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for VOC emissions from natural gas-fired boilers, good combustion practices was identified as the only feasible control option. Efficient combustion includes tuning of the burners within the boiler to achieve the maximum combustion efficiency, which reduces the amount of carbon exiting the stack. This option also includes proper tuning of process control systems to ensure that temperature, natural gas usage, and oxygen levels within the combustion zone remain within appropriate ranges.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion in the boiler is the only remaining feasible control technology. As stated above, this efficient combustion would consist of conducting preventive steps to ensure that the proper fuel to air ratios are maintained, and that fuels with excess carbon content are not introduced into the combustion device.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion of the boiler is the only utilized and most effective for the control of VOC emissions. All six entries in the RBLC also identified good combustion practices as the only control for VOC emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion as BACT for VOC emissions at the start-up boiler. The BACT limits for this source include 0.004 lb VOC/MMBtu per hour heat input at the startup boiler on a 3-hr average, 0.96 lb/hr VOC on a 3-hr average basis, and under Operating Scenario 1, 4.21 tons of VOC per rolling 12 months. Under Operating Scenario 2, the annual limit is reduced to 1.26 tons of VOC per rolling 12 months.

Sulfur Dioxide (SO_2)

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

A four year search of the RBLC was conducted to identify technologies currently in use for the control of SO_2 emissions from boilers across all process types. There were six entries with listed control technologies for SO_2 emissions from natural gas-fired boilers. The following table summarizes the results of the search.

Reference	Facility Name/Location	Control Technology	Date Issued	SO_2 Emission Limit
RBLC ID: OH-0336	Campbell Soup Co. Henry, OH Natural Gas Boilers	None	December 2010	0.0006 lb/MMBtu
RBLC ID: NV-0050	MGM Mirage Clark Co., NV Mandalay Bay	Good Combustion Practices	November 2009	0.0006 lb/MMBtu
RBLC ID: NV-0050	MGM Mirage Clark Co., NV City Center	Good Combustion Practices	November 2009	0.0007 lb/MMbtu
RBLC ID: NV-0050	MGM Mirage Clark Co., NV City Center	Good Combustion Practices	November 2009	0.0024 lb/MMBtu
RBLC ID: NV-0050	MGM Mirage Clark Co., NV New York – New York	Good Combustion Practices	November 2009	0.0050 lb/MMBtu
RBLC ID: OH-0310	American Municipal Power Meigs Co., OH 150 MMBtu/hr Boiler	None	October 2009	0.0006 lb/MMBtu

Step 2: Eliminate Technically Infeasible Options

Based on the results of the RBLC search for SO_2 emissions at boilers, good combustion practices and the use of low sulfur fuel were identified as the only feasible control options.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Proper and efficient combustion and the use of low sulfur fuel at the startup boiler is the only feasible control option.

Step 4: Evaluate Most Effective Controls and Document Results

Good and efficient combustion and the use of low sulfur fuel are the only utilized and most effective control options for SO_2 emissions.

Step 5: Select BACT

EDCC has selected good and efficient combustion and the use of low sulfur fuel as BACT for the startup boiler. The BACT limits for this source include 0.00074 lb SO_2/MMBtu at the startup boiler on a 3-hr average basis, 0.18 lb/hr SO_2 on a 3-hr average basis, and under Operating Scenario 1, 0.77 tons of SO_2 per rolling 12 months. Under Operating Scenario 2, the annual limit is reduced to 0.23 tons of SO_2 per rolling 12 months.

CO_2e Emissions from the Start-up Boiler

Top-Down BACT Analysis

Step 1: Identify All Control Technologies

The following have been proposed as potential CO_2 emission control technologies for the start-up boiler:

- Carbon capture and sequestration
- Energy efficiency design and operation
- Blowdown heat recovery
- Condensate return system
- Cogeneration
- Alternative fuels

Carbon capture and sequestration as well as energy efficiency design and operation are previously described above. Therefore, they are not described again below with the other identified available CO_2 control technologies.

Blowdown Heat Recovery

Blowdown rates are site-specific and dependent on existing water quality as well as make-up water quality. Blowdown has energy that is wasted and typically not recovered. Waste heat from blowdown could be recovered via heat exchanger, a flash tank, or a flash tank in combination with a heat exchanger.

Condensate Return System

Hot condensate not returned to the boiler is wasted energy. A condensate return system may allow the plant to realize a reduction in water related treatment costs, decreased amount of make-up water needed, as well as discharge fees. The energy condensate is returned at a hot temperature (typically between 130 – 225 °F). Whereas makeup water typically has colder in-coming temperatures (typically between 50–60 °F), and therefore must be heated. A condensate return system must be a function of the specific boiler, water quality and condensate; but it is essentially a piping and distribution system.

Cogeneration

Cogeneration is the production of useful steam and electricity from a single plant. Use of cogeneration can provide energy efficiency from the previously wasted heat. Typically, thermal electrical generation is inefficient and therefore results in a loss of greater than 50% of waste heat. By recovering this energy for steam, and/or hot water production has the potential to increase the efficiency of the process by greater than 70%. Increasing the efficiency of the process results in a decrease in the amount of fuel required.

Alternative Fuels

The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Currently, pure biomass fuels include animal meal, landfill gas, sawdust, waste wood products, and sewage sludge.

Step 2: Eliminate Technically Infeasible Options

As part of the BACT analysis, the control technologies identified as part of Step 1 are reviewed for their technical feasibility. A control technology is considered to be technically feasible if it has been previously installed and is in practice at a similar source and/or process and is operating successfully.

Carbon Capture and Sequestration

The technical infeasibility of CCS relative to combustion sources and the EDCC site has been previously described above. Therefore, it is not described again within this section.

Cogeneration

The start-up boiler is being installed for this project to supply process steam to the ammonia plant and NAP. Using the start-up boiler as a cogeneration unit may require several modifications that may impact the overall project and create potential changes such as, site reconfiguration, or process modifications. As a result, this technology would redefine the facility's use for the start-up boiler. Consequently, cogeneration is considered to be technically infeasible.

It is anticipated that the start-up boiler will utilize natural gas as fuel. Currently, natural gas is the lowest GHG-emitting fossil fuel that could be used to provide the required steam production at the facility. In addition, natural gas is the feedstock for the ammonia process. As a result, natural gas as a low-GHG emitting fossil fuel and readily available process feedstock within the facility essentially renders alternative fuels technically infeasible for the start-up boiler.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Currently, the technically feasible CO_2 option for the start-up boiler is the potential implementation of energy efficiency design and operation primarily focused on good combustion practices; and firing only natural gas. The most recent RBLC entry identified for CO_2 has a BACT limit at 117 lb CO_2/MMBtu.

Step 4: Evaluate Most Effective Controls and Document Results

Currently, the technically feasible CO_2 reduction option for the start-up boiler that may be implemented is energy efficiency design and operation including good combustion practices that will achieve a BACT emission rate of 117 lb CO_2/MMBtu firing only natural gas. Based on the current energy efficiency design that is being specified as part of this project, it is expected that the CO_2 emissions from the start-up boiler will be consistent with the aforementioned BACT limit and therefore it is not necessary to further evaluate environmental, energy or economic impacts of the technology.

Step 5: Select BACT

In summary, BACT for GHG control for the start-up boiler is anticipated to include firing only natural gas and inherent design specifications to meet the aforementioned limit. CO_2 emissions from the startup boiler may not exceed 117 lb MMBtu/hr based on three 1-hour stationary source testing runs utilizing USEPA Method 3A. Methane BACT limits for the startup boiler may not exceed 0.0022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 18. Also, the N_2O emissions from the start-up boiler may not exceed 0.00022 lb/MMBtu based on three 1-hour stationary source testing runs utilizing USEPA Method 320. In addition, under Operating Scenario 1 the total CO_2e emissions of 123,410.99 tons per 12-month rolling averaging period shall not be exceeded. Under Operating Scenario 2, the annual limit is reduced to 37,023.69 tons per 12-month rolling averaging period.

A summary of the BACT limits for SN-61 can be found in the following table:

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-61	Start-up Boiler (240 MMBtu/hr)	Opacity	Combustion of natural gas, and good and efficient operating practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.18 lb/hr (3-hr average) 0.23 tons per rolling 12 months
		VOC		0.004 lb/MMBtu (3-hr average) 0.96 lb/hr (3-hr average) 1.26 tons per rolling 12 months
		CO		0.037 lb/MMBtu (3-hr average) 8.88 lb/hr (3-hr average) 11.67 tons per rolling 12 months
		NO_x	Low NOx burners and flue gas recirculation at the boiler Combustion of clean fuel Good Combustion Practices	0.018 lb/MMBtu (3-hr average) 4.32 lb/hr (3-hr average) 5.68 tons per rolling 12 months
		GHG	Good operating practices	CO_2 117 lb/MMBtu CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 37,023.69 tons per rolling 12 months

Ambient Air Impact Analysis

Significance Analysis

The significance analysis considers only the emissions associated with the proposed changes along with other creditable contemporaneous changes at the facility to determine if the proposed project's emissions will have a significant impact on the surrounding area. A "significant" impact occurs when the modeled ambient concentration resulting from the modeled emission rates exceeds an applicable Modeling Significance Level (MSL). The following table summarizes the applicable MSLs and Monitoring De Minimis Concentrations in micrograms per cubic meter ($\mu g/m^3$).

Pollutant	Averaging Period	Maximum-Modeled Concentration ($\mu g/m^3$)	Modeling Significance Level ($\mu g/m^3$)	Monitoring De Minimis Concentration ($\mu g/m^3$)
CO	1-Hour	1029	2,000	--
	8-Hour	335	500	575
SO_2	1-Hour	0.7	7.8	--
	3-Hour	0.4	25.0	--
NO_2	1-Hour	154	7.8	
	Annual	3.4	1.0	14

As shown above, the CO and SO_2 MSLs and Monitoring De Minimis Concentration are not exceeded by impacts from the proposed project. Since the modeled impacts do not exceed the MSL for CO or SO_2, a full impact analysis is not required for CO and SO_2.

The full impact modeling analysis also requires modeling to show that the emissions from the facility and surrounding existing sources will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. A summary of the results of the NAAQS analysis is in the table below.

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1 - Hour	276	Ozone monitoring data from Shreveport, LA (Site ID #220150008) was used for the Tier 3 modeling methodology	171.0[a]	188
	Annual	55.1		55.1	100

a. The highest modeled concentration was 276 $\mu g/m^3$ occuring on Lion Oil's property (AFIN 70-00016). Lion Oil's property is fenced off, thus the air inside their property is not ambient air. When excluding Lion Oil's contribution to the NAAQS evaluation on their property, the total impact was 53 $\mu g/m^3$. The highest off-site impacts in the rest of the modeling area were predicted to be 171.0 $\mu g/m^3$. Therefore, there are no modeled NAAQS exceedances.

The following table shows the results of the PSD increment modeling.

Pollutant	Averaging Period	Maximum Predicted Increment Consumption ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Percent of Class II Increment (%)
NO_2	Annual	16.4	25	65.6

This maximum concentration occurred approximately 7 kilometers to the south of EDCC. Directly surrounding EDCC's property boundary, the maximum annual concentration was 9.5 $\mu g/m^3$. Additionally, the maximum annual concentration is well below the Class II increment of 25 $\mu g/m^3$. Because increment consumption is determined by subtracting emissions occurring at the time of the baseline date from current emission rates and modeling the difference, the resulting concentrations would only decrease from what is reflected in the NAAQS analysis. Therefore, the NAAQS analysis for annual NO_2 emissions also demonstrates that the increment level of 25 $\mu g/m^3$ has not been exceeded. Although the 16.4 $\mu g/m^3$ concentration is above 50% of the increment, the expansion project at EDCC does not have an adverse effect on the industrial and economic development of the area. At the location of the maximum concentration, EDCC has a contribution of 0.2 $\mu g/m^3$, which is an insignificant impact on the increment. Additionally, the maximum impact that EDCC has on the increment (6.0 $\mu g/m^3$) is located on the EDCC property boundary and reflects 24% of the total increment. It is unlikely that any future growth will take place near or in close proximity to EDCC or a nearby existing facility property. Therefore, this project would not limit additional growth in the area. Because this project is an expansion and is not a new facility, alternative siting is not a viable option.

Additional Impact Analysis

An additional impact analysis is completed based on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the project's area of impact. The additional impact analysis consists of three parts: (1) growth, (2) soils and vegetation impacts, and (3) visibility impairment. Each of these analyses is presented in this section.

The purpose of the growth analysis is to predict the amount of new growth likely to occur to support the proposed project under review and to estimate the emissions that will result from the associated growth. First, an assessment is made regarding the amount of residential growth the proposed project will bring to the area. This depends on the size of the available work force, the number of new employees, and the availability of housing in the area. Associated commercial and industrial growth consists of new sources providing goods and services to the new employees and to the new source itself. Once these anticipated growth effects have been considered, an estimate of the air pollutant emissions that would likely result from the associated growth is made. The assessment of additional growth issues and the estimates of emissions increases are conducted based on several types of EPA guidance.

Analysis of the impact of air emissions on soils and vegetation is based on an inventory of the soils and vegetation types found in the impact area. This inventory includes all vegetation of any commercial or recreational significance. For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS do not result in harmful effects.

The visibility impairment analysis considers the impacts that occur within the impact area of the modified source. The visibility analysis considers issues similar to the Class I area visibility analysis requirements. The visibility impairment analysis consists of a determination of the visual quality of the area based on an evaluation of historical data.

Growth Analysis

The purpose of the growth analysis is to predict quantitatively the amount of new growth likely to occur to support the source or modification under review and to estimate the emissions that will result from the associated growth. First, an assessment is made regarding the amount of residential growth the modified source will bring to the area. This depends on the size of the available work force, the number of new employees, and the availability of housing in the area. Associated commercial and industrial growth consists of new sources providing goods and services to the new employees and to the modified source itself. Once these anticipated growth effects have been considered, an estimate of the air pollutant emissions that would likely result from the associated growth is made.

The expansion at EDCC will require the addition of process and construction equipment that will be necessary to facilitate the expansion. However, due to the location of the facility, it is expected to have a negligible effect on the local residential growth in the area. Due to the location of the facility, residential areas are not concentrated around EDCC and thus have no impact on air pollutant emissions in the area. Thus, the anticipated industrial, commercial, and residential growth in the local area due to this project is expected to be negligible.

Soil and Vegetation Analysis

Analysis of the impact of air emissions on soils and vegetation is based on an inventory of the soils and vegetation types found in the impact area. This inventory includes all vegetation of any commercial and recreational significance. For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS do not result in harmful effects.

EDCC is located on industrial property north of El Dorado, AR. Based on the United States Department of Agriculture (USDA) Soil Conservation Service general soil map for Union County, Arkansas, the primary soil types for the approximately 10,000 acres surrounding and including the facility are Sacul-Sawyer complex (45%) and Guyton silt loam (19.1 %).

The agricultural and livestock profile of Union County shows the area consisting primarily of forestland (88.2%), with the primary products being cattle, hay, and harvested timber. No sensitive aspects of the soil and vegetation in the El Dorado area have been identified that would be adversely affected by the proposed expansion at EDCC. Consequently, the secondary NAAQS, which establish the ambient concentrations levels below which no harmful effects to either soil or vegetation can be expected, are used as an indicator of potentially adverse impacts.

As demonstrated in the Ambient Air Impact section, the maximum ambient air impact from the proposed modification is below the NAAQS values. Therefore, any impact to the soil and vegetation as a result of the proposed modification is expected to be negligible.

Visibility Analysis

EPA prescribes the use of its *Workbook for Plume Visual Impact Screening and Analysis* for conducting a visibility impairment analysis. EPA outlines three levels of screening procedures. If the criteria for the first, most conservative, screening level are met, no further analysis is required.

The VISCREEN model is recommended for the first level (Level 1) screen. If predicted values from the VISCREEN model are greater than the standardized screening values, the emissions are judged to have the potential for visibility impairment. If the potential for visibility impairment is indicated, the next level analysis, Level 2 analysis, is required.

The VISCREEN model primarily considers NO_2 and particulate matter emission increases associated with a modification. For this application, the NO_2 and particulate matter emissions are being reduced when compared to currently permitted rates. VISCREEN does not consider or calculate visibility impacts due to ozone. Thus, a VISCREEN analysis is not required in association with this PSD application because there are no applicable emission increases.

To evaluate visibility for Class II areas, VISCREEN was utilized to determine if any visual impacts occur as a result of the project. As outlined in the VISCREEN summary, a location specific background visual range of 25 kilometers was used along with an assumed minimum distance of 50 kilometers and a maximum distance of 170 kilometers (reflecting the distance of the nearest Class I area). In addition to the particulate and NO_X emissions requested in the inputs, NO_2 emissions of 36.5 lb/hr (20% of the total NO_X) was assumed instead of the default 10% due to the nature of the project. The result was that no visual impacts were predicted due to the project.

Finally, it must be determined whether the proposed project has any impact on long and short range visibility impairment. As an initial screening method, the Federal Land Mangers' Air Quality Related Values Work Group released a Natural Resource Report in 2010 that outlined the requirements for determining how to address any potential visibility impacts. In this document, the group outlines the first tier screening method based on a source's annual emission rate and distance from a Class I area.

In the case of EDCC, the facility's proposed NO_x, SO_2, PM_{10}, and H_2SO_4 emissions total is 1,652 tons per year, and the nearest Class I area is located 170 kilometers to the northwest (Caney Creek Wilderness). Therefore, the ratio of emissions to distance for EDCC is 9.72. This is below the Federal Land Management and EPA allowable ratio of 10; therefore, further visibility analysis is not required.

PSD Class I Analysis

The nearest Class I area is the Caney Creek Wilderness, which is approximately 170 km from the mill. The results of the short-range analyses conducted as part of this application combined with the distance from the nearest Class I area make it reasonable to conclude that the proposed project will not exceed a Class I area Increment standard and will not adversely affect Class I area air quality related values.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective June 18, 2010
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 27, 2013
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective November 18, 2012
EDCC is classified as a PSD major stationary source pursuant to 40 CFR 52.21
40 CFR Part 60, Subpart Db - *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Regulations
The DM Weatherly Nitric Acid Plant #1 (SN-13) is subject to New Source Performance Standards 40 CFR 60 Subpart G, 60.70 through 60.74 (*Standards of Performance for Nitric Acid Plants*)
The DM Weatherly Nitric Acid Plant # 2 (SN-59) is subject to New Source Performance Standards 40 CFR Part 60, Subpart Ga – *Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011*
The Sulfuric Acid Plant (SN-07) is subject to 40 CFR 60 Subpart H (Standards of Performance for Sulfuric Acid Plants).
40 CFR Part 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
40 CFR Part 63, Subpart DDDDD - *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*
40 CFR Part 64, Compliance Assurance Monitoring

This facility is classified as a major source of greenhouse gas emissions.

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	Total Allowable Emissions	PM	54.8	120.9
		PM_{10}	47.7	95.1
		$PM_{2.5}$	46.0	89.1
		SO_2	93.6	403.4
		VOC	56.1	184.8
		CO	185.5	161.7
		NO_X	997.88	724.7
		Lead	0.07	0.07
		CO_2e	719,243.9	2,773,524.4
		N_2O	1,337.8	5,053.7
	HAPs	Arsenic* Cadmium* Formaldehyde* Hexane* Methanol* Mercury*	0.07 0.07 0.14 2.04 32.69 0.07	0.07 0.07 0.40 8.44 143.19 0.07
	Air Contaminants **	HNO_3	4.01	11.91
		H_2SO_4	2.90	12.58
		NH_3	1,843.08	890.57
		SO_3	0.04	0.18
SN-02	Emissions routed to SN-41			
SN-03	Emissions routed to SN-41			
SN-04	Emissions routed to SN-41			

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-05	Ammonium Nitrate E2 Brinks Scrubber	PM PM_{10} $PM_{2.5}$ NH_3**	2.5 2.5 2.5 8.50	10.9 10.9 10.9 37.30
SN-06	E2 Ammonium Nitrate Prill Tower Fans	Emissions routed to SN-05		
SN-07	Sulfuric Acid Plant	SO_2 H_2SO_4**	92.0 2.83	401.5 12.35
SN-08	West (Weak) Nitric Acid Plant	NO_x N_2O N_2O as CO_2e NH_3**	52.2 532.5 165,056.4 40.00	228.6 2,026.8 628,293.7 62.20
SN-09	East (Weak) Nitric Acid Plant	NO_x N_2O N_2O as CO_2e NH_3**	52.2 532.5 165,056.4 40.00	228.6 2,026.8 628,293.7 62.20
SN-10	Nitric Acid Vent Collection System	NO_x HNO_3**	19.5 3.81	85.1 11.06
SN-13	DM Weatherly Nitric Acid Plant # 1 (controlled by SCR)	NO_x N_2O N_2O as CO_2e NH_3**	16.7 252.2 78,172.7 1.39	42.0 910.0 282,100.0 6.09
SN-14	KT LDAN Prill Tower	PM PM_{10} $PM_{2.5}$	1.2 1.2 1.2	5.0 5.0 5.0
SN-15	KT Plant Dryer/Cooler	PM PM_{10} $PM_{2.5}$ NH_3**	0.8 0.8 0.8 27.00	3.2 3.2 3.2 118.26
SN-17	E2 HDAN Plant Cooling Train	Exhaust from Pease Anthony Scrubber is routed to SN-05		
SN-18	KT Plant Clay Baghouse	PM PM_{10} $PM_{2.5}$	1.5 1.5 1.5	1.9 1.9 1.9
SN-19	E2 Plant Barometric Tower	PM PM_{10} $PM_{2.5}$ NH_3**	0.5 0.5 0.5 4.04	1.9 1.9 1.9 17.70

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-20	Emissions routed to SN-41			
SN-21	KT Plant Brinks Scrubber	PM PM_{10} $PM_{2.5}$ NH_3**	0.4 0.4 0.4 45.00	1.5 1.5 1.5 197.10
SN-25	Gasoline Storage Tank (2000 Gallon)	VOC	13.4	1.4
SN-26	Ammonium Nitrate (90% Solution) Storage	NH_3**	0.21	0.77
SN-27	KT Plant LDAN Loading	PM PM_{10} $PM_{2.5}$	0.9 0.1 0.1	4.0 0.1 0.1
SN-28	E2 Plant HDAN/LDAN Loading	PM PM_{10} $PM_{2.5}$	1.2 0.1 0.1	5.3 0.1 0.1
SN-29	Nitric Acid Loading	Emissions are routed to SN-10		
SN-30	Sulfuric Acid Loading	H_2SO_4**	0.03	0.05
SN-31	Frick Ammonia Compressors	NH_3**	0.44	1.92
SN-32	Ammonia Storage/Distribution	NH_3**	1.59	6.97
SN-33	Nitric Acid Production Fugitives	NO_x HNO_3**	0.1 0.01	0.1 0.02
SN-34	E2 Plant Solution Reactor	PM PM_{10} $PM_{2.5}$	1.1 1.1 1.1	4.5 4.5 4.5
SN-35	Magnesium Oxide Silo Baghouse	PM PM_{10} $PM_{2.5}$	2.0 2.0 2.0	0.4 0.4 0.4
SN-37	Car Barn Scrubber	Source removed in 2008, emissions now routed to SN-10		
SN-38	DM Weatherly Nitric Acid Plant # 1 Cooling Tower	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.4 0.4 0.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-40	Ammonium Nitrate Solution Loading	NH_3**	0.22	0.63
SN-41	E2 Plant Chemical Steam Scrubber (30-day rolling average)	PM PM_{10} $PM_{2.5}$ NH_3**	3.4 3.4 3.4 10.00	14.6 14.6 14.6 43.80
SN-41	E2 Plant Chemical Steam Scrubber (daily 24-hr average)	PM PM_{10} $PM_{2.5}$ NH_3**	13.8 13.8 13.8 10.00	-- -- -- --
SN-44	Mixed Acid Plant Scrubber	NO_x SO_3** H_2SO_4** HNO_3**	0.4 0.04 0.04 0.19	1.7 0.18 0.18 0.83
SN-46	Sulfuric Acid Plant Cooling Tower	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-47	Nitric Acid Concentration (NACSAC®) Plant	NO_x	0.2	0.6
SN-48	DM Weatherly Nitric Acid Plant # 1 Tail Gas Heater (20 MMBtu/hr)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_x CO_2e Arsenic* Cadmium* Formaldehyde* Hexane* Mercury* Lead	0.2 0.2 0.2 0.1 0.2 1.7 1.0 2,348.1 0.01 0.01 0.01 0.04 0.01 0.01	0.7 0.7 0.7 0.1 0.5 7.3 4.3 10,284.2 0.01 0.01 0.01 0.16 0.01 0.01

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-49	Ammonia Plant Primary Reformer	PM	3.5	15.2
		PM_{10}	3.5	15.2
		$PM_{2.5}$	3.5	15.2
		SO_2	0.7	0.5
		VOC	1.2	5.1
		CO	16.0	70.1
		NO_x	10.3	44.8
		CO_2e	96,737.6	423,714.2
		Arsenic*	0.01	0.01
		Cadmium*	0.01	0.01
		Formaldehyde*	0.07	0.27
		Hexane*	1.46	6.37
		Mercury*	0.01	0.01
		Lead	0.01	0.01
SN-50	Ammonia Plant Condensate Steam Stripper	VOC	5.9	25.6
		CO_2e	396.7	1,737.4
		NH_3**	0.60	2.50
		Methanol*	4.90	21.50
SN-51	Ammonia Plant CO_2 Regenerator	VOC	33.7	147.4
		CO	1.2	5.2
		CO_2e	146,262.6	640,669.2
		NH_3**	2.70	11.60
		Methanol*	27.80	121.8
SN-52	Ammonia Plant Cooling Tower	PM	0.5	2.1
		PM_{10}	0.5	2.1
		$PM_{2.5}$	0.5	2.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-53	Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.1	0.4
		NO_x	792.1	6.9
		CO_2e	7,304.2	719.9
		NH_3**	1,584.05	9.73
		Arsenic*	0.01	0.01
		Cadmium*	0.01	0.01
		Formaldehyde*	0.01	0.01
		Hexane*	0.01	0.01
		Mercury*	0.01	0.01
		Lead	0.01	0.01
SN-54	Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)	PM	0.3	0.1
		PM_{10}	0.3	0.1
		$PM_{2.5}$	0.3	0.1
		SO_2	0.1	0.1
		VOC	0.2	0.1
		CO	0.8	0.2
		NO_x	2.3	0.6
		CO_2e	4,461.3	1,115.4
		Arsenic*	0.01	0.01
		Cadmium*	0.01	0.01
		Formaldehyde*	0.01	0.01
		Hexane*	0.08	0.02
		Mercury*	0.01	0.01
		Lead	0.01	0.01
SN-55	Ammonia Plant Fugitives	NH_3**	15.50	67.60

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-56	Ammonia Plant Process SSM Flare	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	156.1	39.4
		NO_x	0.1	0.5
		CO_2e	18,787.9	5,179.8
		Arsenic*	0.01	0.01
		Cadmium*	0.01	0.01
		Formaldehyde*	0.01	0.01
		Hexane*	0.01	0.01
		Mercury*	0.01	0.01
		Lead	0.01	0.01
SN-57	Ammonia Storage Flare	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.1	0.1
		NO_x	10.1	43.9
		CO_2e	20.6	90.0
		NH_3**	40.00	175.20
		Arsenic*	0.01	0.01
		Cadmium*	0.01	0.01
		Formaldehyde*	0.01	0.01
		Hexane*	0.01	0.01
		Mercury*	0.01	0.01
		Lead	0.01	0.01
SN-58	Ammonia Rail and Truck Loading	NH_3**	9.20	13.01
SN-59	DM Weatherly Nitric Acid Plant # 2	NO_x	33.78	17.8
		N_2O	20.6	90.1
		CO_2e	6,371.5	27,911.3
		NH_3**	2.64	11.54
SN-60	DM Weatherly Nitric Acid Plant # 2 Cooling Tower	PM	0.5	2.1
		PM_{10}	0.5	2.1
		$PM_{2.5}$	0.5	2.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-61	Start-up Boiler (240 MMBtu/hr) Operating Scenario # 1	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_x Lead CO_2e Arsenic* Cadmium* Formaldehyde* Hexane* Mercury*	2.4 2.4 2.0 0.2 1.0 8.9 4.4 0.01 28,176.2 0.01 0.01 0.02 0.44 0.01	10.6 10.6 8.5 0.8 4.3 38.9 19.0 0.01 123,411.0 0.01 0.01 0.08 1.86 0.01
SN-61	Start-up Boiler (240 MMBtu/hr) Operating Scenario # 2	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_x Lead CO_2e Arsenic* Cadmium* Formaldehyde* Hexane* Mercury*	2.4 2.4 2.0 0.2 1.0 8.9 4.4 0.01 28,176.2 0.01 0.01 0.02 0.44 0.01	3.2 3.2 2.6 0.3 1.3 11.7 5.7 0.01 37,023.7 0.01 0.01 0.03 0.56 0.01
SN-62	Haul Road Fugitives	PM PM_{10} $PM_{2.5}$	6.7 1.5 0.2	20.8 4.4 0.5
SN-63	KT Plant Chemical Steam Scrubber (30-day rolling average)	PM PM_{10} $PM_{2.5}$ NH_3**	3.4 3.4 3.4 10.19	14.8 14.8 14.8 44.63
SN-63	KT Plant Chemical Steam Scrubber (daily 24-hr average)	PM PM_{10} $PM_{2.5}$ NH_3**	14.0 14.0 14.0 10.19	-- -- -- --

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-64	KT LDAN Warehouse Fugitives	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.4 0.1 0.1
SN-65	Emergency Water Pump	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_x CO_2e	0.2 0.2 0.2 0.2 0.2 0.6 2.5 91.7	0.1 0.1 0.1 0.1 0.1 0.1 0.2 4.6

* - HAPs included in the PM/VOC totals. Other HAPs are not included in any other totals unless specifically stated.
** - Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

The chemical plant located at 4500 North West Avenue in El Dorado, Arkansas and currently owned and operated by El Dorado Chemical Company has equipment that dates back to 1944 to the initial facility built by the U.S. Army Corps of Engineers and operated for the U.S. Government by Lion Oil Company.

Permit No. 122-A was issued July 13, 1972 to Monsanto Company for additional absorption trays and refrigeration to reduce the opacity from the East and West regular nitric acid plants (SN-08 and SN-09). Existing plants at that time and their date of installations were: Boilers (1944), Sulfuric Acid Plant (1949), the E2 Ammonium Nitrate Plant (1950), and East and West Nitric Acid Plants (1962).

Permit No. 123-A was issued July 13, 1972 to Monsanto Company to tie the Nitric Acid Concentrators exhausts into an existing fume scrubber to reduce opacity.

Permit No. 124-A was issued July 13, 1972 to Monsanto Company to install mist eliminators on the Ammonia Nitrate neutralizers and concentrators to reduce particulate matter emissions.

Permit No. 168-A was issued June 22, 1973 to Monsanto Company to install a wet scrubber to reduce the particulate matter emission from the ammonium nitrate prilling towers.

Permit No. 0573-A was issued to Monsanto Agricultural Products Company on August 8, 1979 for the installation of a mist eliminator for the emissions of the sulfuric acid plant to lower the emission factor from this equipment below 0.5 lb acid mist / ton of 100 percent acid produced, as required by Section 111(d) of the Clean Air Act.

Permit No. 0573-AR-1 was issued on September 23, 1983 when El Dorado Chemical, Inc. purchased the facility from Monsanto Company. All previous permits for this facility were rescinded. Permit Limits for SN-1 thru SN-10 were established in pounds per hour (not tpy) and the opacity limits for all sources except SN-8 and SN-9 (nitric acid plants) were established at 40%.

Permit No. 0573-AR-2 was issued on March 23, 1984 for the conversion of the E2 ammonium nitrate plant to allow some of its production to be low density product in addition to the high density product it was already producing.

Permit No. 0573-AR-3 was issued on September 11, 1989 for the expansion of the facility by adding the DM Weatherly nitric acid plant (subject to NSPS 40 CFR Part 60 Subpart G) and the KT ammonium nitrate plant and its associated prill tower. Emissions netting occurred with the issuance of this permit to avoid PSD review. The PSD trigger limits were established in this permit for particulate matter (203 tpy) and NO_x (8076 tpy).

Permit No. 0573-AR-4 was issued on June 6, 1991 reflecting the stack testing results required by the previous permit. Additionally, comprehensive inventories on production and air emissions record keeping were started on particulate matter and NO_x to insure that the annual emission limits due to PSD offsetting were not exceeded. The 1988/1989 (two years prior to 0573-AR-3) average actual emissions were recalculated and the PSD trigger limits were re-established at 281 tpy for particulate matter and 8202 tpy for NO_x.

Permit No. 0573-AR-5 was issued on November 7, 1991 to further incorporate stack testing results obtained since the previous permit was issued.

Permit No. 0573-AR-6 was issued on March 15, 1993 to install a scrubber on the KT Prill Plant and a secondary ammonium nitrate concentrator in the Low Density Ammonium Nitrate Plant. This lowered the ammonia and particulate matter emissions from the KT Ammonium Nitrate Plant.

Permit No. 0573-AR-7 was issued on September 6, 1994 for a facility expansion to install the UHDE Concentrated Nitric Acid Plant with an increase in NO_x emissions of 149.9 tpy. This Plant was incorrectly listed as being subject to NSPS 40 CFR Part 60 Subpart G when the permit was issued. The operation of the sulfuric acid concentrators (SN-01A and SN-01B) and the nitric acid concentrator (SN-10) with 288.1 tpy average actual NO_x emissions over the previous 5 years (314.5 tpy permitted NO_x emissions) were scheduled to cease six months after the plant start-up.

The UHDE Concentrated Nitric Acid Plant did not have a smooth startup when operation started in July, 1995. The permittee applied for a variance October 5, 1995 requesting continued operation of SN-01A, SN-01B, and SN-10 through July 1, 1996 while the concentrated nitric acid plant went through extended debugging.

A series of three Consent Administrative Orders were issued (CAO LIS No. 95-183, CAO LIS No. 95-183-001, CAO LIS No. 95-183-002) after the variance expired allowing the continued operation of SN-01A, SN-01B, and SN-10. These documents also required permitting of additional sources at the facility, installation of emission control equipment improvements by the permittee, and a thorough PSD review of all changes at the facility. The major emission control improvement was the installation of Selective Catalytic Reduction (SCR) units on SN-08 and SN-09. This resulted in a permitted reduction of 5,124 tpy NO_x for these two sources, and an actual emission reduction in excess of 2,700 tpy NO_x. A demister was also installed on the emissions from the North and South Sulfuric Acid Concentrator (SN-01A and SN-01B) which reduced sulfuric acid mist emissions by at least 50%.

Permit No. 0573-AOP-R0 was issued to El Dorado Chemical Company on October 21, 1999. This permit allowed a small capacity increase for the UHDE DSN Plant (SN-22) resulting in a 27.5 tpy increase in the NO_x emission limit for that source. The permittee was also granted an option of installing a CEM on the Sulfuric Acid Plant (SN-07) and after the completion of the CEM, a daily production increase to 360 tons. Emission limits for the permit were: PM/PM_{10} - 297.0 tpy, SO_2 - 2520.4 tpy, VOC - 2.7 tpy, CO - 25.4 tpy, NO_x. - 3002.5 tpy, HNO_3 - 242.3 tpy, H_2SO_4 - 66.6 tpy, and NH_3 - 404.1 tpy.

Permit No. 0573-AOP-R1 was issued to El Dorado Chemical Company on June 29, 2000. This permit modification was issued to resolve the appeal filed regarding the initial Title V permit. Primary changes are in the short term compliance mechanism in several of the Specific Conditions and the required testing Specific Conditions regarding opacity. One small source (SN-19) was deleted from the initial permit resulting in a 1.0 lb/hr reduction in the hourly particulate limits and no change in the yearly limit. Emission limits for the permit were: PM/PM_{10} - 297.0 tpy, SO_2 - 2520.4 tpy, VOC - 2.7 tpy, CO - 25.4 tpy, NO_x. - 3002.5 tpy, HNO_3 - 242.3 tpy, H_2SO_4 - 66.6 tpy, NH_3 - 404.1

Permit No. 0573-AOP-R2 was issued to El Dorado Chemical Company on December 3, 2001. This permit modification was issued to change the quantitative opacity observations for SN-27 and SN-28 from EPA Method 9 to EPA Method 22 (because both sources are non-point sources). The testing of the liquid in the peroxide scrubber in Specific Condition No. 24 was changed from a pH test to a hydrogen peroxide concentration test. ADEQ also modified the permit to clarify the reporting requirements and identify records that must be included in the semi-annual report specified in General Provision 7. The emission limits of the permit did not change in this modification.

Permit No. 0573-AOP-R3 was issued on February 20, 2003. This modification included the installation of a new ammonium nitrate transfer system to handle the finished ammonium nitrate product from the KT Ammonium Nitrate Plant, the installation of the new ammonium nitrate neutralizer in the E2 Ammonium Nitrate Plant, and the use of a "hard wired" PM_{10} emission factor in demonstrating compliance with the Plantwide Applicability Limit for sources SN-01 through SN-21. Emissions of PM/PM_{10} at SN-27 increased from 2.6 tpy to 2.7 tpy, as a result of the installation of a new ammonium nitrate transfer system (SN-27) at the KT Ammonium Nitrate Plant. Emissions of ammonia at SN-05 increased from 40.0 lb/hr to 45.7 lb/hr, as a result of the simultaneous operation of three ammonium neutralizers in the E2 Ammonium Nitrate Plant. The annual ammonia emissions remained the same. Additionally, there was no modification to the Prill Tower with this change. The increase in PM_{10} actual emissions was 14.8 ton/year at SN-05 and SN-06, which was less than the 15.0 ton/year threshold for PSD significance level. In the ammonia dispersion modeling submitted with this application, the facility did not include ammonia emissions from SN-11. SN-11 was prohibited from operation until stack testing was performed at this unit. The air dispersion modeling results showed the maximum ambient impacts did not exceed any 1/100 TLV concentrations at any modeled receptor. Plantwide PM_{10} emissions remained the same as listed in Permit #0573-AOP-R2.

Permit 0573-AOP-R4 was issued on June 30, 2003. This modification included the installation of a car barn scrubber (SN-37). Nitric acid emissions from cleaning and pressure checking rail cars were rerouted from the nitric acid concentrator vents (SN-10) to the scrubber (SN-37) at the car barn. There were no changes in plantwide nitric acid emissions.

Permit 0573-AOP-R5 was issued on April 12, 2005. This Title V air permit renewal included the installation of a new chemical steam scrubber (SN-41) at the E2 Plant, permitting four existing cooling towers (SN-38, SN-39, SN-42, and SN-43) and existing ammonium nitrate solution loading (SN-40), and revising the stack testing requirements for the Nitric Acid Vent

Collection System (SN-10), Sulfuric Acid Plant (SN-07), E2 HDAN Plant Cooling Train (SN-17), KT Plant Dryer/Cooler (SN-15), and the KT Plant Brinks Scrubber (SN-21). Emission rates were re-evaluated to reflect updated emission factors and additional stack test data. Maximum potential operation hours at SN-08 and SN-09 were increased from 8400 hours per year to 8760 hours per year. Emission rates for the two boilers (SN-16A and SN-16B) were updated using USEPA AP-42 emission factors. Two sources (SN-11 and SN-12) were removed. The E2 Plant Barometric Tower (SN-19), at one time deleted from permit, was incorporated back into the permit.

Permit 0573-AOP-R6 was issued on April 13, 2006. This modification included the installation of a new Mixed Acid Plant Scrubber (SN-44), revision of the language of stack testing for SN-05, removal of stack testing requirements for SN-06, clarification of permit requirements and revision of control equipment monitoring parameters in the permit issued on April 12, 2005 and the agreed upon changes in the Permit Appeal Resolution (PAR). This modification also incorporated hard-wired emission factors for the E2 and KT plants, and a PSD application to increase the ammonium nitrate production limit of the E2 Plant to the maximum equipment potential. Plantwide condition #7 was revised to have the following language: "... does not include the quantity of condensable particulate measured through the back-half sampling train procedure of EPA Reference Method 5...". This was because the back-half sampling train procedure of Reference Method was not available when this condition was first put in the permit for PSD netting offset purposes.

Permit 0573-AOP-R7 was issued on February 16, 2007. This modification included the routing of the exhaust from Pease Anthony (Venturi) Scrubber on the E2 HDAN Plant Cooling Train (SN-17) to the Ammonium Nitrate E2 Brinks Scrubber (SN-05) for additional control, the removal of the particulate matter stack testing requirements for SN-17, and the revision of the PM_{10} hard-wired emission factor for the E2 Plant.

Permit 0573-AOP-R8 was issued on August 26, 2008. This permitting action included the following revisions:

Production capacity increase at SN-07 to 550 ton/day (200,750 ton/year);
Addition of a SSMP for SN-07, SN-08, SN-09, SN-13, SN-22, and SN-41;
Addition of ammonia emissions at SN-08 and SN-09;
Installation of an additional auxiliary air compressor at the East and West Nitric Acid Plant process area and at the DM Weatherly Nitric Acid Plant; and
Removed the Car Barn Scrubber (SN-37) and route the nitric acid emissions to Nitric Acid Vent Collection System (SN-10).

The permitted emissions decreases included 2,115.5 tpy of SO_2, 20.45 tpy of Sulfuric Acid Mist. The permitted emissions increases included 124.4 tpy of Ammonia and 0.7 tpy of Nitric Acid. There were no permitted NO_X emission changes with the installation of the auxiliary air compressors.

Permit 0573-AOP-R9 was issued on February 17, 2009. This minor modification authorized the installation of the sulfuric acid cooling tower (SN-46). This mechanically induced, cross-flow draft cooling tower is an integral part of the double absorption process required by CAO LIS 03-175 (December 31, 2003). The potential emissions increase from this modification was 0.7 tpy of PM/PM_{10}.

Permit 0573-AOP-R10 was issued on October 26, 2009. With this modification the facility requested:

1. Revisions to particulate matter (PM/PM_{10}) monitoring requirements (Specific Condition # 61) for the E2 Plant Chemical Steam Scrubber (SN-41) based on the Environmental Protection Agency's (EPA's) position on condensable PM in the recently released New Source Review (NSR) implementation rule for $PM_{2.5}$.
2. Relocation of the Ammonium Nitrate (AN) Solution Loading facility (SN-40).
3. Removal of the obsolete Sampling Method for SN-41 (Appendix D) from the permit.
4. Revisions to the PM/PM_{10} stack testing requirements (Specific Condition # 67 and added Specific Condition # 68) for the KT LDAN Dryer/Cooler (SN-15) based on EPA's current position on condensable PM.
5. Corrections to compliance demonstration references for various specific conditions related to the E2 Ammonium Nitrate Plant, KT Ammonium Nitrate Plant, Natural Gas Fired Boilers, and the Magnesium Oxide Silo Baghouse.

The modification authorized all of the above requests except for #1. Revisions to a BACT limit requires PSD review, as such the BACT limit remained until the facility submits a PSD application. There were no permitted emission changes with the modification.

The facility submitted an Administrative Amendment on August 28, 2009 to implement Ammonia offloading operations to the Insignificant Activities list. The Ammonia offloading operations were added during the comment period for permit 0573-AOP-R10.

Permit 0573-AOP-R11 was issued on November 24, 2010. With this Title V Renewal the facility requested:

1. Update emission limits for SN-25, SN-28, SN-30, SN-33, SN-40, and SN-44. Revisions to SN-28 and SN-33 are due to rounding. Revisions to SN-25 are due to updates to the TANKS software. Revisions to SN-30 are due to revisions based on actual production capabilities. Revisions to SN-40 are due to previous calculation errors. Revisions to SN-44 are due to a reduction in oleum concentration.
2. Remove Specific Conditions # 44 and # 46 which required EDCC to install, test, and operate SO_2 removal technology in accordance with Consent Administrative Order, LIS 03-175. The unit has been installed.
3. Limit the Oleum concentration to a maximum of 30%. The lower limit is due to Occupational Safety and Health Administration (OSHA) issues and transportation regulations.
4. Correct various compliance mechanisms to add consistency and clarification.

5. EDCC also submitted a Prevention of Significant Deterioration (PSD) application to revise the Best Available Control Technology (BACT) limit at SN-41. The facility retained the BACT limit for the scrubber at 0.054 lb particulate per ton of Ammonium Nitrate (AN) solution for normal operations based on a 30-day rolling average. The facility incorporated a startup and shutdown BACT limit for the scrubber which was set at 0.223 lb particulate per ton of AN solution. The facility did not request to increase annual emissions from SN-41.

With the renewal, the total permitted emission changes included increases of 0.1 tpy of PM/PM_{10}, 0.4 tpy of VOC, and 0.1 tpy of NO_x, and a decrease of 6.4 tpy of SO_2.

Permit 0573-AOP-R12 was issued on October 11, 2011. With this modification the facility requested to:

1. Incorporate the requirements of 40 CFR Part 63, Subpart CCCCCC – *National Emission Standards For Hazardous Air Pollutants For Source Category: Gasoline Dispensing Facilities*; and
2. To incorporate Reference Method 202 into particulate matter sampling requirements at the KT Plant Dryer/Cooler (SN-15) as required by Specific Condition 90 of Permit 0573-AOP-R11.

There were no permitted emission changes with this modification.

Permit 0573-AOP-R13 was issued on June 18, 2012. With this modification the facility requested to incorporate ADEQ's Continuous Emissions Monitoring Systems (CEMS) Conditions for the stack gas sampling system at the E2 Plant Chemical Steam Scrubber (SN-41). There were no permitted emission changes with this modification.

Permit 0573-AOP-R14 was issued on October 29, 2012. On May 14, 2012, a reactor at the Direct Strong Nitric Acid Plant exploded, causing significant damage to process equipment at the Sulfuric Acid Plant (SN-07). With this modification the facility requested to repair and replace damaged process equipment associated with the Sulfuric Acid Plant (SN-07), the Sulfuric Acid Loading (SN-30), the Sulfuric Acid Cooling Tower (SN-46), and the Molten Sulfur Storage Tank (Insignificant Activity). The hourly SO_2 emission limit for the Sulfuric Acid Plant (SN-07) was reduced from 600 lb/hr to 92.0 lb/hr to be consistent with the applicable provisions of 40 CFR Part 60, Subpart H – *Standards of Performance for Sulfuric Acid Plants*. A 2,000 gallon diesel storage tank was also added to the insignificant activities. There were no permitted annual emission changes with this modification.

Permit 0573-AOP-R15 was issued on March 1, 2013. On May 14, 2012, a reactor at the Direct Strong Nitric Acid Plant exploded, causing significant damage to process equipment at the Sulfuric Acid Plant (SN-07). With this modification the facility requested:

1. Install a Selective Catalytic Reduction (SCR) Unit and install a natural gas fired heater (Tail Gas Heater, SN-48) at the DM Weatherly Nitric Acid Plant (SN-13);

2. Take a limit on the potential to emit from the existing boilers (SN-16A & SN-16B) to avoid triggering PSD for CO_2e; and
3. Install a nitric acid concentration plant (NACSAC® Plant, SN-47) to replace the facility's strong nitric acid production capability that was lost due to the shutdown of the Direct Strong Nitric Acid Plant.

Items 2 and 3 were withdrawn and were not be processed because the facility had plans for the nitric acid concentration plant in the future that include taking weak acid from any of the existing or new acid plants. The facility indicated that they intend on submitting a PSD application to install a new weak nitric acid plant and an ammonia plant in the near future. Therefore, installation of the NACSAC plant is related to the future PSD project. A significant emissions increase did not occur due to installing a SCR and a Tail Gas Heater at the DM Weatherly Nitric Acid Plant. The hybrid test for projects that involve multiple types of emissions units indicated that there would be the following increases:

The permitted emission increases included 0.7 tpy of $PM/PM_{10}/PM_{2.5}$, 0.1 tpy of SO_2, 0.5 tpy of VOC, 7.3 tpy of CO, 4.3 tpy of NO_x, and 6.2 tpy of NH_3. With this permitting action, the potential Green House Gas (GHG) emissions from SN-13 and SN-48 are being added to the permit. The potential GHG emissions from SN-13 and SN-48 include 292,384.3 tpy of CO_2e and 910.0 tpy of N_2O.

SECTION IV: SPECIFIC CONDITIONS

East and West Regular Nitric Acid Plants

SN-08 and SN-09
East and West Nitric Acid Plant

Source Description

The East and West Nitric Acid Plants produce weak nitric acid at concentrations ranging from 52% to 58%. The West Nitric Acid Plant (SN-08) and East Nitric Acid Plant (SN-09) each utilize a C&I Girdler single pressure process to produce weak nitric acid. The East and West Nitric Acid Plants are not subject to NSPS 40 CFR 60, Subpart G – New Source Performance Standard for Nitric Acid Plants, because they were constructed prior to August 17, 1971. The air emissions from these processes are the tail gases from the absorption columns. The absorption columns employ bleaching air to oxidize nitrogen oxide to nitrogen dioxide. The amount of bleaching air used in the process controls the oxygen in the tail gases. The tail gases, which consist of nitrogen oxides, are passed through Selective Catalytic Reduction (SCR) Units before being vented to the atmosphere. The SCR units remove nitrogen oxide emissions by reacting ammonia with nitrogen oxide to form nitrogen gas and water vapor.

The stacks are equipped with a nitrogen oxide continuous emission monitoring systems (CEMS), which shall be operated in accordance with the ADEQ CEMS conditions. The CEMS will also be operated consistent with proposed elements of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. Each unit has a production capability of 152,387.5 tons of nitric acid per year.

The uncontrolled emissions from SN-08 and SN-09 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because it meets the following criteria: (1) the units are subject to emission limitations for NO_x, (2) the sources are equipped with a control device, and (3) the units have potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for these sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limits at these sources.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 17.4 tons per hour of weak nitric acid production. Compliance with this condition shall be demonstrated by compliance with Specific Conditions 4 through 10, and satisfactory operation of the SCR Units. [Regulation 19, §19.501 et seq., and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
08	West Nitric Acid Plant	NO_x	52.2	228.6
		N_2O	532.5	2,026.8
		N_2O as CO_2e	165,056.4	628,293.7
09	East Nitric Acid Plant	NO_x	52.2	228.6
		N_2O	532.5	2,026.8
		N_2O as CO_2e	165,056.4	628,293.7

2. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 17.4 tons per hour of weak nitric acid production. Compliance with the lb/hr limit for ammonia for SN-08 and SN-09 will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 11. Compliance with the ton per year limit will be demonstrated by complying with the lb/hr limit. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
08	West Nitric Acid Plant	NH_3	40.00	62.20
09	East Nitric Acid Plant	NH_3	40.00	62.20

3. The permittee shall not exceed 10% opacity from the West Nitric Acid Plant and the East Nitric Acid Plant as measured by EPA Reference Method 9. Compliance with the opacity limit set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee shall not manufacture in excess of 17.4 tons 100% acid equivalent per hour of weak nitric acid through each of the nitric acid plants (SN-08 and SN-09). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

5. The permittee shall not manufacture in excess of 152,387.5 tons 100% acid equivalent per rolling 12-month total of weak nitric acid through each of the nitric acid plants (SN-08 and SN-09). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

6. The permittee shall keep records of the production manufactured in the east and west nitric acid plants as specified in Specific Conditions 4 and 5. These records shall contain the production for each hour as specified in Specific Condition 4, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

7. The West Nitric Acid Plant (SN-08) must continuously have NO_x emissions that do not exceed 3.0 lb/ton of weak nitric acid production on a 3-hour rolling average at all times. The permit shall demonstrate compliance with this condition by complying with Specific Condition 9. [Regulation 19, §19.501 et seq.; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; and 40 CFR 70.6]

8. The East Nitric Acid Plant (SN-09) must continuously have NO_x emissions that do not exceed 3.0 lb/ton of weak nitric acid production on a 3-hour rolling average at all times. The permit shall demonstrate compliance with this condition by complying with Specific Condition 9. [Regulation 19, §19.501 et seq.; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; and 40 CFR 70.6]

9. The permittee shall install, calibrate, maintain, and operate a Continuous Emission Monitoring System (CEMS) to monitor NO_x and N_2O emissions from the West Nitric Acid Plant (SN-08) and the East Nitric Acid Plant (SN-09). The NO_x monitor shall be operated in accordance with the ADEQ CEMS conditions and shall be operated at all times including during startup and shutdown. Compliance will be demonstrated on a rolling 3-hour average. [Regulation 19, §19.703; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee shall not exceed the N_2O limit of 30.6 lb/ton at each of the nitric acid plants (SN-08 and SN-09). Compliance with this condition will be verified by compliance with Specific Condition 9. [Regulation 19, §19.501 et seq. and §19.705; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; 40 CFR Part 52, Subpart E ; and 40 CFR 70.6]

11. The permittee shall test SN-08 and SN-09 for ammonia emissions. This test shall be conducted within 180 days after the issuance of Air Permit 0573-AOP-R8 and every 60 months thereafter. Test method CTM-027 or an equivalent method approved by the Department shall be used for Ammonia. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the

failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. This unit shall be operated at 90% or more of rated capacity when the tests are completed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. The 60-month testing cycle shall commence after the issuance of Air Permit 0573-AOP-R8 in accordance with Plantwide Condition 3. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

DM Weatherly Nitric Acid Plant # 1

SN-13
DMW Nitric Acid Plant # 1

Source Description

The DMW Nitric Acid Plant # 1 (SN-13) produces weak nitric acid (61%-67% strength) by oxidizing ammonia in the presence of a platinum catalyst. The major contributor to air emissions from this process is the absorption column tail gas. In the absorption column, nitrogen dioxide is absorbed into condensate with nitric acid exiting the absorption column. The efficiency of this process determines the amount of nitrogen oxides released to the atmosphere in the tail gas. A SCR will be used to control the NO_x emissions from SN-13. This nitric acid plant was originally installed at the American Cyanamid Company facility at Hannibal, Missouri and was relocated to the El Dorado Chemical in 1990. This plant is subject to NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants), because it was constructed or modified after August 17, 1971 and produces weak nitric acid (between 30% and 70 % strength).

The uncontrolled emissions from SN-13 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for NO_x, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limit at this source.

Specific Conditions

12. The permittee shall not exceed the emission limits set forth in the following table for source SN-13. The hourly emission limits are based on maximum capacity of 16.7 tons per hour of weak nitric acid production. Compliance with this condition will be verified by compliance with Specific Conditions 15, 16, 18, 19, and 20. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
13	DM Weatherly Nitric Acid Plant # 1 (controlled by SCR)	NO_x	16.7	42.0
		N_2O	252.2	910.0
		N_2O as CO_2e	78,172.7	282,100.0

13. The permittee shall not exceed the emission limits set forth in the following table for source SN-13. The emission rates are based on maximum capacity and vendor specification. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
13	DM Weatherly Nitric Acid Plant # 1 (controlled by SCR)	NH_3	1.39	6.09

14. The permittee shall not exceed 10% opacity from the DM Weatherly Nitric Acid Plant # 1 (SN-13) as measured by EPA Reference Method 9. Compliance with the opacity limit set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

15. The permittee shall not manufacture in excess of 16.7 tons 100% acid equivalent per hour of weak nitric acid through the DM Weatherly Nitric Acid Plant # 1 (SN-13). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

16. The permittee shall not manufacture in excess of 140,000 tons 100% acid equivalent per rolling 12-month of weak nitric acid through the DM Weatherly Nitric Acid Plant # 1 (SN-13). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

17. The permittee shall keep records of the production manufactured at the DM Weatherly Nitric Acid Plant # 1 (SN-13) as specified in Specific Conditions 15 and 16. These records shall contain the production for each hour as specified in Specific Condition 15, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

18. The DM Weatherly Nitric Acid Plant # 1 (SN-13) must continuously have NO_x emissions that do not exceed 1.0 lb/ton of 100% nitric acid production on a 3-hr rolling average basis, excluding startup, shutdown, and malfunction (SSM) related emissions and 0.6 lb/ton of 100% nitric acid production on a 365-day rolling average basis, including SSM related emissions. The permittee shall establish a conversion factor for converting this reading to pounds NO_2 per ton of 100 percent acid produced (60.73(b)), and in accordance with the CEMS Plan (listed as Appendix J in the back of this permit). An hourly value shall be computed by the system for each hour the plant is operating. The permittee shall keep records of daily production rates and hours of operation (60.73(c)).

The permittee shall report to the Department as excess emissions any 3-hour period in which the average emissions (arithmetic average of any 3 consecutive hours) from the facility exceed 3.0 lb/ton of 100% nitric acid production (60.73(e)). During periods of startup, shut down, malfunction events, compliance with the limits shall be demonstrated using a CEMS to measure the NO_x concentration and flow monitor. The permittee shall report any 3-hour period in which the NO_x emissions (arithmetic average of any 3 consecutive hours) from the facility exceed 50.1 lb/hr. [Regulation 19 §19.501 et seq.; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; and NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants) (listed as Appendix B in the back of this permit)]

19. The permittee shall install, calibrate, maintain, and operate a dual range CEMS and stack gas flow meter to monitor NO_x emissions from the DM Weatherly Nitric Acid Plant # 1 (SN-13) in accordance with the CEMS Plan (listed as Appendix J in the back of this permit). The permittee shall install, calibrate, maintain, and operate the dual range monitor and stack gas flow meter with the following operational requirements, which are included in the CEMS Plan:

Analyzer	Parameter	Location	Span Value
NO_x Stack Analyzers	NO_x, ppm by volume, dry basis[1]	Stack	Normal: 0 – 500 ppm NO_x, or as appropriate to accurately measure the normal concentration range. SSM: 0 to 125% of the maximum estimated NO_x emission concentration
Stack Flow meter	Volumetric Flow rate, SCFH[2]	Stack	0 to 125% of the maximum expected volumetric flow rate

[1]For the purposes of calculations under the CEMS Plan in Appendix J, as-is NO_x concentration measurements at the DM Weatherly Nitric Acid Plant # 1(e.g., those utilizing FTIR, NDIR, or other types of stack gas analyzers capable of making wet measurements) will be assumed to be dry. However, the permittee may adjust for any moisture contained in the stack gas if the nitric acid plant is equipped with a continuous moisture analyzer or equipment which removes the moisture prior to the stack gas analyzer.
[2]For the purposes of the calculations under the CEMS Plan, as-is volumetric flow rate measurements will be assumed to be dry. However, the permittee may adjust for any moisture contained in the stack gas if the nitric acid plant is equipped with a continuous moisture analyzer.

[A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

20. The permittee shall use the dual range CEMS specified in Specific Condition 19 to monitor NO_x and N_2O emissions from the DM Weatherly Nitric Acid Plant # 1 (SN-13). Compliance will be demonstrated on a rolling 3-hour average. [Regulation 19, §19.703; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

21. The permittee shall not exceed the N_2O limit of 15.1 lb/ton at the DM Weatherly Nitric Acid Plant # 1 (SN-13). Compliance with this condition will be verified by compliance

with Specific Conditions 19 and 20. [Regulation 19, §19.501 et seq. and §19.705; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; 40 CFR Part 52, Subpart E ; and 40 CFR 70.6]

22. The permittee shall have a third party annually stack test the Ammonia emissions from SN-13 within 180 days of startup of the DM Weatherly Nitric Acid Plant # 1 (SN-13) after installation of the control equipment, and every 12 months thereafter. The stack test shall be performed using method CTM-027 or an equivalent method approved by the Department shall be used for ammonia. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-38
DMW Nitric Acid Plant # 1 Cooling Tower

Source Description

EDCC operates a cooling tower as part of the DMW1 Nitric Acid Plant operations. During operation, water droplets become entrained in the air stream and are carried out of the cooling tower, called "drift". Because the drift droplets generally contain the same chemical impurities as the water circulating through the tower, these impurities can be converted to airborne particulate emissions.

Specific Conditions

23. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by compliance with Specific Condition 26. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
38	DM Weatherly Nitric Acid Plant # 1 Cooling Tower	PM_{10}	0.1	0.4
		$PM_{2.5}$	0.1	0.4

24. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 26. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
38	DM Weatherly Nitric Acid Plant # 1 Cooling Tower	PM	0.1	0.4

25. The permittee shall not exceed 20% opacity from the DM Weatherly Nitric Acid Plant # 1 Cooling Tower as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-38 is demonstrated by compliance with Specific Condition 26. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

26. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-38 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-38's requirements in Specific Conditions 23, 24, and 25 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-48
DMW Nitric Acid Plant # 1 Tail Gas Heater

Source Description

This 20 MMBtu/hr natural gas fired heater is used to increase the temperature of the tail gas prior to its introduction to the SCR Unit.

Specific Conditions

27. The permittee shall not exceed the emission rates set forth in the following table. The emission rate limit is based on maximum capacity of the unit. The permittee shall demonstrate compliance with this condition by Specific Condition 29. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
48	DM Weatherly Nitric Acid Plant # 1 Tail Gas Heater (20 MMBtu/hr)	PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.2	0.5
		CO	1.7	7.3
		NO_x	1.0	4.3
		CO_2e	2,348.1	10,284.2
		Lead	0.01	0.01

28. The permittee shall not exceed the emission rates set forth in the following table. The emission rate limit is based on maximum capacity of the unit. The permittee shall demonstrate compliance with this condition by Specific Condition 29, Plantwide Conditions 13 through 42, and Table 3 to 40 CFR Part 63, Subpart DDDDD. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
48	DM Weatherly Nitric Acid Plant # 1 Tail Gas Heater (20 MMBtu/hr)	PM	0.2	0.7
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.04	0.16
		Mercury	0.01	0.01

29. The permittee shall burn only pipeline quality natural gas in SN-42. [Regulation 19, §19.705, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

30. The permittee shall not exceed 5% opacity from the Tail Gas Heater (SN-48) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-48 shall be demonstrated by compliance with Specific Condition 29. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

31. The permittee shall comply with the following table from 40 CFR Part 63, Subpart DDDDD:

Table 3 to Subpart DDDDD of 40 CFR Part 63 – Work Practice Standards

If your unit is . . .	You must meet the following . . .
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under 40 CFR Part 63, Subpart DDDDD. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.

SN-59
DM Weatherly Nitric Acid Plant # 2

Source Description

EDCC proposes to add a second DM Weatherly Nitric Acid Plant as a part of the proposed facility expansion. The DM Weatherly Nitric Acid Plant #2 (DMW2 Plant, or SN-59) will produce weak nitric acid (61-67% strength) by oxidizing ammonia in the presence of a platinum catalyst. Significant emissions from this process include unreacted nitrogen oxides (NO_x) from the absorption step in the process. Construction of this plant will include installation of a Selective Catalytic Reduction (SCR) unit to control NO_x emissions, which will allow NO_x emissions to be reduced to meet the NSPS Subpart Ga (Standards of Performance for Nitric Acid Plants for which Construction, Reconstruction, or Modification Commenced After October 14, 2011) limit of 0.5 lb/ton of 100% nitric acid produced (30-day rolling average basis, including SSM related emissions). EDCC will utilize tertiary abatement technology to control N_2O emissions from DMW2.

Specific Conditions

32. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the NO_x limits by compliance with Specific Conditions 34, 36, 37, 38, 40, and 41. The permittee shall demonstrate compliance with the N_2O limits by compliance with Specific Conditions 34, 36, 37, 38, and 40. [Regulation 19 §19.901 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
59	DM Weatherly Nitric Acid Plant # 2	NO_x	33.78[a]	17.8
			3.38[b]	
			26.35[c]	
		N_2O	20.6	90.1
		N_2O as CO_2e	6,371.5	27,911.3

a. 3-hr average including SSM.
b. 30-day rolling total excluding SSM.
c. 30-day rolling total including SSM.

33. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 36, 37, 38, and 39. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
59	DM Weatherly Nitric Acid Plant # 2	NH_3	2.64	11.54

34. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 36, 37, 38, and 40. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-59	DM Weatherly Nitric Acid Plant # 2	Opacity	SCR with extended absorption, good and efficient operating practices	0%
		NO_x		100 ppm$_v$ (3-hr average including SSM) 0.64 lb/ton (3-hr average including SSM) 33.78 lb/hr (3-hr average including SSM) 5 ppm$_v$ (Rolling 30-day average excluding SSM) 0.064 lb/ton (Rolling 30-day average excluding SSM) 3.38 lb/hr (Rolling 30-day average excluding SSM) 0.5 lb/ton of 100% Nitric Acid (Rolling 30-day average including SSM) 26.35 lb/hr (Rolling 30-day average including SSM) 6 ppm$_v$ (Rolling 12 months including SSM) 17.76 tons per rolling 12 months (Including SSM)

		GHG	Tertiary catalytic reduction	N_2O 30 ppm_v (3-hr average) N_2O 0.39 lb/ton (3-hr average) N_2O 20.6 lb/hr (3-hr average) N_2O 98% destruction efficiency N_2O 90.04 tons per rolling 12 months CO_2e 27,911.28 tons per rolling 12 months

35. The permittee shall not exceed 0% opacity from the DM Weatherly Nitric Acid Plant # 2 (SN-59) as measured by EPA Reference Method 9. Compliance with the opacity limit set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501; Regulation 19, §19.901 et seq.; and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

36. The permittee shall not manufacture in excess of 52.7 tons 100% acid equivalent per hour of weak nitric acid through the DM Weatherly Nitric Acid Plant # 2 (SN-59). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

37. The permittee shall not manufacture in excess of 461,725 tons 100% acid equivalent per rolling 12-month total of weak nitric acid through the DM Weatherly Nitric Acid Plant # 2 (SN-59). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

38. The permittee shall keep records of the production manufactured in the DM Weatherly Nitric Acid Plant # 2 (SN-59) as specified in Specific Conditions 36 and 37. These records shall contain the production for each hour as specified in Specific Condition 36, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

39. The permittee shall not exceed the NH_3 limit of 0.05 lb/ton at the DM Weatherly Nitric Acid Plant # 2 (SN-59). The permittee shall have a third party stack test the NH_3 emissions from SN-59 within 180 days after initial start up, and every 12 months thereafter. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test. The permittee shall test method CTM-027 or an equivalent method approved in advance by the Department. Testing shall be conducted with the source operating at least at 90% of its permitted capacity. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test

and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. Testing shall be conducted in accordance with Plantwide Condition 3. SN-59 has a maximum capacity rated at 52.7 ton/hr of acid production. [Regulation 19, §19.702 and §19.705; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; 40 CFR Part 52, Subpart E ; and 40 CFR 70.6]

40. The permittee shall use the CEMS required in Specific Condition 45 to monitor the N_2O emissions from the DM Weatherly Nitric Acid Plant # 2 (SN-59). The permittee shall not exceed the N_2O limit of 0.39 lb/ton at the DM Weatherly Nitric Acid Plant # 2 (SN-59). Compliance will be demonstrated on a rolling 3-hour average. [Regulation 19, §19.703; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

41. DM Weatherly Nitric Acid Plant # 2 (SN-59) is considered an affected source under 40 CFR Part 60, Subpart Ga - *Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011*, and is subject to, but not limited to, Specific Conditions 42 through 71. [Regulation 19, §19.304 and 40 CFR Part 60, Subpart Ga]

42. On and after the date on which the performance test required to be conducted by §60.73a(e) is completed, you may not discharge into the atmosphere from any affected facility any gases which contain NO_x, expressed as NO_2, in excess of 0.50 pounds (lb) per ton of nitric acid produced, as a 30-day emission rate calculated based on 30 consecutive operating days, the production being expressed as 100 percent nitric acid. The emission standard applies at all times. [§60.72a]

43. You must install and operate a NO_x concentration (ppmv) continuous emissions monitoring system (CEMS). You must also install and operate a stack gas flow rate monitoring system. With measurements of stack gas NO_x concentration and stack gas flow rate, you will determine hourly NO_x emissions rate (e.g., lb/hr) and with measured data of the hourly nitric acid production (tons), calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). You must operate the monitoring system and report emissions during all operating periods including unit startup and shutdown, and malfunction. [§60.73a(a)]

44. You must install, calibrate, maintain, and operate a CEMS for measuring and recording the concentration of NO_x emissions in accordance with the provisions of §60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of 40 CFR Part 60. You must use cylinder gas audits to fulfill the quarterly auditing requirement at section 5.1 of Procedure 1 of Appendix F of 40 CFR Part 60 for the NO_x concentration CEMS. [§60.73a(b)(1)]

45. For the NO_x concentration CEMS, use a span value, as defined in Performance Specification 2, section 3.11, of Appendix B of 40 CFR Part 60, of 500 ppmv (as NO_2). If you emit NO_x at concentrations higher than 600 ppmv (e.g., during startup or shutdown periods), you must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NO_x emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods. [§60.73a(b)(2)]

46. For conducting the relative accuracy test audits, per Performance Specification 2, section 8.4, of Appendix B of 40 CFR Part 60 and Procedure 1, section 5.1.1, of Appendix F of 40 CFR Part 60, use either EPA Reference Method 7, 7A, 7C, 7D, or 7E of Appendix A-4 of 40 CFR Part 60; EPA Reference Method 320 of Appendix A of 40 CFRP Part 63; or ASTM D6348-03 (incorporated by reference, see §60.17). To verify the operation of the second CEMS or the higher range of a dual analyzer CEMS described in paragraph (b)(2) of §60.73a, you need not conduct a relative accuracy test audit but only the calibration drift test initially (found in Performance Specification 2, section 8.3.1, of Appendix B of 40 CFR Part 60) and the cylinder gas audit thereafter (found in Procedure 1, section 5.1.2, of Appendix F of 40 CFR Part 60). [§60.73a(b)(3)]

47. If you use EPA Reference Method 7E of Appendix A-4 of 40 CFR Part 60, you must mitigate loss of NO_2 in water according to the requirements in paragraphs (b)(4)(i), (ii), or (iii) of §60.73a and verify performance by conducting the system bias checks required in EPA Reference Method 7E, section 8, of Appendix A-4 of 40 CFR Part 60 according to (b)(4)(iv) of §60.73a, or follow the dynamic spike procedure according to paragraph (b)(4)(v) of §60.73a.

   a. For a wet-basis measurement system, you must measure and report temperature of sample line and components (up to analyzer inlet) to demonstrate that the temperatures remain above the sample gas dew point at all times during the sampling.
   b. You may use a dilution probe to reduce the dew point of the sample gas.
   c. You may use a refrigerated-type condenser or similar device (e.g., permeation dryer) to remove condensate continuously from sample gas while maintaining minimal contact between condensate and sample gas.
   d. If your analyzer measures nitric oxide (NO) and nitrogen dioxide (NO_2) separately, you must use both NO and NO_2 calibration gases. Otherwise, you must substitute NO_2 calibration gas for NO calibration gas in the performance of system bias checks.
   e. You must conduct dynamic spiking according to EPA Reference Method 7E, section 16.1, of Appendix A-4 of 40 CFR Part 60 using NO_2 as the spike gas.

   [§60.73a(b)(4)]

48. Instead of a NO_x concentration CEMS meeting Performance Specification 2, you may apply an FTIR CEMS meeting the requirements of Performance Specification 15 of

Appendix B of 40 CFR Part 60 to measure NO_x concentrations. Should you use an FTIR CEMS, you must replace the Relative Accuracy Test Audit requirements of Procedure 1 of appendix F of 40 CFR Part 60 with the validation requirements and criteria of Performance Specification 15, sections 11.1.1 and 12.0, of Appendix B of 40 CFR Part 60. [§60.73a(b)(5)]

49. You must use the NO_x concentration CEMS, acid production, gas flow rate monitor and other monitoring data to calculate emissions data in units of the applicable limit (lb NO_x /ton of acid produced expressed as 100 percent nitric acid). [§60.73a(c)]

50. You must install, calibrate, maintain, and operate a CEMS for measuring and recording the stack gas flow rates to use in combination with data from the CEMS for measuring emissions concentrations of NO_x to produce data in units of mass rate (e.g., lb/hr) of NO_x on an hourly basis. You will operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of § 60.13 and Performance Specification 6 of Appendix B of 40 CFR Part 60. You must comply with the following provisions in (c)(1)(i) through (iii) of §60.73a.

    a. You must use a stack gas flow rate sensor with a full scale output of at least 125 percent of the maximum expected exhaust volumetric flow rate (see Performance Specification 6, section 8, of Appendix B of 40 CFR Part 60).
    b. For conducting the relative accuracy test audits, per Performance Specification 6, section 8.2 of Appendix B of 40 CFR Part 60 and Procedure 1, section 5.1.1, of Appendix F of 40 CFR Part 60, you must use either EPA Reference Method 2, 2F, or 2G of Appendix A-4 of 40 CFR Part 60. You may also apply Method 2H in conjunction with other velocity measurements.
    c. You must verify that the CERMS complies with the quality assurance requirements in Procedure 1 of Appendix F of 40 CFR Part 60. You must conduct relative accuracy testing to provide for calculating the relative accuracy for RATA and RAA determinations in units of lb/hour.

[§60.73a(c)(1)]

51. You must determine the nitric acid production parameters (production rate and concentration) by installing, calibrating, maintaining, and operating a permanent monitoring system (e.g., weigh scale, volume flow meter, mass flow meter, tank volume) to measure and record the weight rates of nitric acid produced in tons per hour. If your nitric acid production rate measurements are for periods longer than hourly (e.g., daily values), you will determine average hourly production values, tons acid/hr, by dividing the total acid production by the number of hours of process operation for the subject measurement period. You must comply with the following provisions in (c)(2)(i) through (iv) of §60.73a.

    a. You must verify that each component of the monitoring system has an accuracy and precision of no more than ±5 percent of full scale.

b. You must analyze product concentration via titration or by determining the temperature and specific gravity of the nitric acid. You may also use ASTM E1584-11 (incorporated by reference, see § 60.17), for determining the concentration of nitric acid in percent. You must determine product concentration daily.
c. You must use the acid concentration to express the nitric acid production as 100 percent nitric acid.
d. You must record the nitric acid production, expressed as 100 percent nitric acid, and the hours of operation.

[§60.73a(c)(2)]

52. You must calculate hourly NO_x emissions rates in units of the standard (lb/ton acid) for each hour of process operation. For process operating periods for which there is little or no acid production (e.g., startup or shutdown), you must use the average hourly acid production rate determined from the data collected over the previous 30 days of normal acid production periods (see § 60.75a). [§60.73a(c)(3)]

53. For each continuous monitoring system, including NO_x concentration measurement, volumetric flow rate measurement, and nitric acid production measurement equipment, you must meet the requirements in paragraphs (d)(1) through (3) of §60.73a.

a. You must operate the monitoring system and collect data at all required intervals at all times the affected facility is operating except for periods of monitoring system malfunctions or out-of-control periods as defined in Appendix F, sections 4 and 5, of 40 CFR Part 60, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.
b. You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in calculating emissions and the status of compliance with the applicable emissions limit in accordance with §60.72a(a).

[§60.73a(d)]

54. You must conduct an initial performance test to demonstrate compliance with the NO_x emissions limit under § 60.72a(a) beginning in the calendar month following initial certification of the NO_x and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NO_x average concentration, mass flow rate recorded with the certified NO_x concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on

the first day of the first month following completion of the CEMS installation and certification as described above. You must assure that the CERMS meets all of the data quality assurance requirements as per § 60.13 and Appendix F, Procedure 1, of 40 CFR Part 60 and you must use the data from the CERMS for this compliance determination. [§60.73a(e)]

55. In response to an action to enforce the standards set forth in § 60.72a, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief. [§60.74a]

56. To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of §60.74a, and must prove by a preponderance of evidence that:

   a. The violation:
      i. Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and
      ii. Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and
      iii. Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and
      iv. Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and
   b. Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and
   c. The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and
   d. If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
   e. All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and
   f. All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and
   g. All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and
   h. At all times, the affected facility was operated in a manner consistent with good practices for minimizing emissions; and
   i. A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the

violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

[§60.74a(a)]

57. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of §60.74a. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard. [§60.74a(b)]

58. You must calculate the 30 operating day rolling arithmetic average emissions rate in units of the applicable emissions standard (lb NO_x /ton 100 percent acid produced) at the end of each operating day using all of the quality assured hourly average CEMS data for the previous 30 operating days. [§60.75a(a)]

59. You must calculate the 30 operating day average emissions rate according to Equation 1:

$$\frac{E_{30} = k\frac{1}{n}\sum_{i=1}^{n} C_i Q_i}{P_i} \qquad \text{(Eq. 1)}$$

Where:

E_{30} = 30 operating day average emissions rate of NO_x , lb NO_x /ton of 100 percent HNO_3 ;

C_i = concentration of NO_x for hour i, ppmv;

Q_i = volumetric flow rate of effluent gas for hour i, where C_i and Q_i are on the same basis (either wet or dry), scf/hr;

P_i = total acid produced during production hour i, tons 100 percent HNO_3 ;

k = conversion factor, 1.194×10^{-7} for NO_x ; and

n = number of operating hours in the 30 operating day period, i.e., n is between 30 and 720.

[§60.75a(b)]

60. For the NO_x emissions rate, you must keep records for and results of the performance evaluations of the continuous emissions monitoring systems. [§60.76a(a)]

61. You must maintain records of the following information for each 30 operating day period:

a. Hours of operation.
b. Production rate of nitric acid, expressed as 100 percent nitric acid.
c. 30 operating day average NO_x emissions rate values.

[§60.76a(b)]

62. You must maintain records of the following time periods:

a. Times when you were not in compliance with the emissions standards.
b. Times when the pollutant concentration exceeded full span of the NO_x monitoring equipment.
c. Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

[§60.76a(c)]

63. You must maintain records of the reasons for any periods of noncompliance and description of corrective actions taken. [§60.76a(d)]

64. You must maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications. [§ 60.76a(e)]

65. For each malfunction, you must maintain records of the following information:

a. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
b. Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[§60.76a(f)]

66. The performance test data from the initial and subsequent performance tests and from the performance evaluations of the continuous monitors must be submitted to the Administrator at the appropriate address as shown in 40 CFR 60.4. [§60.77a(a)]

67. The following information must be reported to the Administrator for each 30 operating day period where you were not in compliance with the emissions standard:

a. Time period;
b. NO_x emission rates (lb/ton of acid produced);

c. Reasons for noncompliance with the emissions standard; and
d. Description of corrective actions taken.

[§60.77a(b)]

68. You must also report the following whenever they occur:

a. Times when the pollutant concentration exceeded full span of the NO_x pollutant monitoring equipment.
b. Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

[§60.77a(c)]

69. You must report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications. [§60.77a(d)]

70. Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, you must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/SSL/cdx/EPA_Home.asp*). You must submit performance test data in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods listed on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. Mark the compact disk or other commonly used electronic storage media clearly as CBI and mail to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, you must also submit these reports to the delegated authority in the format specified by the delegated authority. You must submit the other information as required in the performance evaluation as described in §60.2 and as required in 40 CFR Chapter I.

[§60.77a(e)]

71. If a malfunction occurred during the reporting period, you must submit a report that contains the following:

a. The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.
b. A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with § 60.11(d), including actions taken to correct a malfunction.

[§60.77a(f)]

SN-60
DM Weatherly Nitric Acid Plant # 2 Cooling Tower

Source Description

The DM Weatherly Nitric Acid Plant # 2 Cooling Tower (SN-60) provides non-contact cooling water to the process equipment in the DM Weatherly Nitric Acid Plant # 2 (SN-59), the East and West Nitric Acid Plants (SN-08 and SN-09), the NACSAC® Plant (SN-47), and the ammonia shipping and storage refrigeration system. Particulate matter is emitted during operation of the cooling tower.

Specific Conditions

72. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 75. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
60	DM Weatherly Nitric Acid Plant # 2 Cooling Tower	PM_{10}	0.5	2.1
		$PM_{2.5}$	0.5	2.1

73. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 75. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
60	DM Weatherly Nitric Acid Plant # 2 Cooling Tower	PM	0.5	2.1

74. The permittee shall not exceed 5% opacity from the DM Weatherly Nitric Acid Plant # 2 Cooling Tower as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-60 is demonstrated by compliance with Specific Condition 75. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

75. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-60 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-60's requirements in Specific Conditions 72, 73, and 74 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Nitric Acid Concentration Plant (NACSAC® Plant)

SN-47
Nitric Acid Concentration Plant (NACSAC® Plant)

Source Description

The PLINKE designed NACSAC® Plant (SN-47) concentrates weak nitric acid (61% - 67% strength) to strong nitric acid (greater than 98% strength) by extracting water from the weak nitric acid with sulfuric acid, which is then dehydrated and recycled to the front end of the process.

Specific Conditions

76. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 78, 79, and 80. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
47	Nitric Acid Concentration Plant (NACSAC® Plant)	NO_x	0.2	0.6

77. The permittee shall not exceed 5% opacity from the Nitric Acid Concentration Plant (SN-47) as measured by EPA Reference Method 9. Compliance with the opacity limit set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

78. The permittee shall not manufacture in excess of 5.2 tons 100% acid equivalent per hour of strong nitric acid through the Nitric Acid Concentration Plant (SN-47). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

79. The permittee shall not manufacture in excess of 45,625 tons 100% acid equivalent per rolling 12-month total of strong nitric acid through the Nitric Acid Concentration Plant (SN-47). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

80. The permittee shall keep records of the production manufactured in the Nitric Acid Concentration Plant (SN-47) as specified in Specific Conditions 78 and 79. These records shall identify any hour during which acid in excess of the quantities specified in Specific Condition 78 was produced, and shall contain each month's total and a rolling

total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

Nitric Acid Vent Collection System

SN-10
Nitric Acid Vent Collection System

Source Description

In October of 1997, a packed tower hydrogen peroxide scrubber was installed to control nitrogen oxide emissions. The top portion of the packed tower treats nitrogen oxide emissions from the weak nitric acid storage vents (Tanks 49, 50, and 51, as well as three (3) new tanks being added with the facility expansion). The bottom section of the packed tower treats the nitrogen oxide emissions present in the blend acid tanks (Tanks 43, 44, 45, and 46) bleaching air stream. The nitric acid loading system vents (SN-29) are also collected and routed to the packed tower. The overheads from the packed tower are routed through a Venturi Scrubber for additional treatment before being vented to the atmosphere through a stack designated as SN-10. The strong nitric acid storage tank vents (Tanks 47, 48, 66, 67, 68, 69, 70 and 71) are routed directly to the Venturi Scrubber (i.e. bypass the packed tower). Overall nitrogen oxide and visible emissions are reduced due to these pollution control devices.

With the issuance of Air Permit 0573-AOP-R8, the Car Barn Scrubber (previously permitted as SN-37) was removed as a source. The nitric acid fumes resulting from the cleaning and pressure checking of rail cars (conducted in the Car Barn) are now routed to SN-10 for control.

The uncontrolled emissions from SN-10 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for NO_x, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limit at this source.

Specific Conditions

81. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by proper operation of the Venturi and Packed Tower Scrubber and compliance with Specific Conditions 84 and 86. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
10	Nitric Acid Vent Collection System	NO_x	19.5	85.1

82. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by proper operation of the Venturi and Packed Tower Scrubber and compliance with Specific Conditions 85 and 86. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
10	Nitric Acid Vent Collection System	Nitric Acid (HNO_3)	3.81	11.06

83. The permittee shall not exceed 20% opacity from the Nitric Acid vent collection system (SN-10) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-10 is demonstrated by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

84. The permittee shall test SN-10 for NO_x emissions. The permittee shall have a third party stack test the NO_x emissions from SN-10 once every 60 months. SN-10 was last tested on November 17, 2010. The permittee shall use EPA Method 7E or a method approved in advance by the Department. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The facility will conduct rail car/truck loading and/or acid blending operations at normal operational rates when the stack test is performed. [Regulation 19, §19.702 and §19.705; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; 40 CFR Part 52, Subpart E ; and 40 CFR 70.6]

85. The permittee shall test SN-10 for Nitric Acid (HNO_3) emissions. The permittee shall have a third party stack test the HNO_3 emissions from SN-10 once every 60 months. SN-10 was last tested on November 17, 2010. The permittee shall use a method approved in advance by the Department. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The equipment which the nitric acid vent collection system serves as a pollution control device shall be operating at normal capacity when the testing is performed. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

86. The permittee shall not operate the nitric acid vent collection system without a functional hydrogen peroxide scrubber and a Venturi and Packed Tower Scrubber. The permittee shall sample, test and record daily the hydrogen peroxide concentration of the chemical

condensate circulated at the scrubber outlet. These records shall be updated by the 15th of the month following which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

Sulfuric Acid Plant

SN-07
Sulfuric Acid Plant

Source Description

The Sulfuric Acid Plant (SN-07), originally constructed in 1949 when Lion Oil Company operated the facility, is a single absorption contact process of the Chemco design. The plant was later modified by Monsanto (Leonard). The plant has been upgraded over the years to include emissions control systems, updated acid cooling technology, and process control equipment.

The Sulfuric Acid Plant (SN-07) manufactures sulfuric acid at 93% - 99% strength through the combustion of sulfur to form sulfur dioxide, the use of oxygen to convert the newly formed sulfur dioxide to sulfur trioxide, and then finally the double absorption of sulfur trioxide with water to form sulfuric acid. The Sulfuric Acid Plant is subject to 40 CFR 60 Subpart H (Standard of Performance for Sulfuric Acid Plants), which limits sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions to 4.0 pounds per ton of 100% acid production and 0.15 pounds per ton of 100% acid production, respectively.

The uncontrolled emissions from SN-07 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for SO_2, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of SO_2 that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the SO_2 emission limit at this source.

Specific Conditions

87. The permittee shall not exceed the emission rates set forth in the following table. Compliance of SO_2 with this Specific Condition is demonstrated by compliance with Specific Conditions 90, 91, 92 and 97. Compliance of SO_2 is also demonstrated by the CEM required in Specific Condition 91c. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
07	Sulfuric Acid Plant	SO_2	92.0[a]	401.5
		SO_2	4.0 lb/ton, expressed as 100 percent H_2SO_4, and based on a 3-hr average.	

a. Based on a 3-hr average.

88. The permittee shall not exceed the emission rates set forth in the following table. Compliance of sulfuric acid mists with this Specific Condition is demonstrated by compliance with Specific Conditions 90 and 91. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
07	Sulfuric Acid Plant	H_2SO_4	2.83	12.35

89. The permittee shall not exceed 10% opacity from the Sulfuric Acid Plant (SN-07) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-07 is demonstrated by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

90. The permittee shall not manufacture in excess of 200,750 tons of 100% sulfuric acid per rolling 12-month total through the sulfuric acid plant. The permittee shall keep records of the amount of sulfuric acid produced at the facility. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; and 40 CFR 70.6]

91. Sulfuric Acid Plant (SN-07) is subject to and shall comply with applicable provisions of 40 CFR Part 60, Subpart H – *Standards of Performance for Sulfuric Acid Plants.* Applicable provisions of Subpart H include, but are not limited to, the following: [Regulation 19, §19.304 and 40 CFR §60.80]

    a. The permittee shall not cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4. [Regulation 19, §19.304 and 40 CFR §60.82]
    b. The permittee shall not cause to be discharged into the atmosphere from any affected facility any gases which:
    (1) Contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H_2SO_4.
    (2) Exhibit 10 percent opacity, or greater.
    [Regulation 19, §19.304 and 40 CFR §60.83]
    c. A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under Performance Specification 2 and for calibration checks under §60.13(d), shall be sulfur dioxide (SO_2). Method 6C shall be used for conducting monitoring system performance

evaluations under §60.13(c). The span value shall be set at 1000 ppm of sulfur dioxide. [Regulation 19, §19.304 and 40 CFR §60.84(a)]

d. The permittee shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999–AP–13) and calculating the appropriate conversion factor for each eight-hour period as follows:
   $CF=k[(1.000-0.015r)/(r-s)]$
   where:
   CF=conversion factor (kg/metric ton per ppm, lb/ton per ppm).
   k=constant derived from material balance. For determining CF in metric units, k=0.0653. For determining CF in English units, k=0.1306.
   r=percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Department's approval.
   s=percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under §60.84(a). [Regulation 19, §19.304 and 40 CFR §60.84(b)]
e. The owner or operator shall record all conversion factors and values under §60.84(b) from which they were computed (i.e., CF, r, and s). [Regulation 19, §19.304 and 40 CFR §60.84(c)]
f. Alternatively, a source that processes elemental sulfur or an ore that contains elemental sulfur and uses air to supply oxygen may use the following continuous emission monitoring approach and calculation procedures in determining SO_2 emission rates in terms of the standard. This procedure is not required, but is an alternative that would alleviate problems encountered in the measurement of gas velocities or production rate. Continuous emission monitoring systems for measuring SO_2, O_2, and CO_2 (if required) shall be installed, calibrated, maintained, and operated by the owner or operator and subjected to the certification procedures in Performance Specifications 2 and 3. The calibration procedure and span value for the SO_2 monitor shall be as specified in §60.84(b). The span value for CO_2 (if required) shall be 10 percent and for O_2 shall be 20.9 percent (air). A conversion factor based on process rate data is not necessary. Calculate the SO_2 emission rate as follows:
   $Es=(CsS)/[0.265-(0.126\ \%O_2)-(A\ \%CO_2)]$
   where:
   Es=emission rate of SO_2, kg/metric ton (lb/ton) of 100 percent of H_2SO_4 produced.
   Cs=concentration of SO_2, kg/dscm (lb/dscf).
   S=acid production rate factor, 368 dscm/metric ton (11,800 dscf/ton) of 100 percent H_2SO_4 produced.
   $\%O_2$=oxygen concentration, percent dry basis.
   A=auxiliary fuel factor,

=0.00 for no fuel.
=0.0226 for methane.
=0.0217 for natural gas.
=0.0196 for propane.
=0.0172 for No 2 oil.
=0.0161 for No 6 oil.
=0.0148 for coal.
=0.0126 for coke.
$\%CO_2$= carbon dioxide concentration, percent dry basis.
[Regulation 19, §19.304 and 40 CFR §60.84(d)]

g. For the purpose of reports under §60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under §60.82. [Regulation 19, §19.304 and 40 CFR §60.84(e)]
h. The permittee shall comply with the test methods and procedures in 40 CFR §60.85. [Regulation 19, §19.304 and 40 CFR §60.85]

92. The permittee shall not exceed the SO_2 limit defined in Specific Condition 91a during any three-hour period. Compliance with this condition shall be demonstrated by the CEM required in Specific Condition 91c. These records shall be kept on site, and shall be made available to Department personnel upon request. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; 40 CFR 60.82, 60.84(a), and 60.84(e); and 40 CFR 70.6]

A reasonable possibility, as defined under paragraph (r)(6) of 40 CFR §52.21, exists for SO_2 due to the maintenance, repair, and replacement (MRR) activities requested in the application for Permit 0573-AOP-R14.

93. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the SO_2 emission limits is demonstrated by compliance with Specific Conditions 90, 91, 92 and 97. Compliance with the SO_2 emission limits is also demonstrated by the CEM required in Specific Condition 91c. [Regulation 19, §19.501 and §19.901; and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
07	Sulfuric Acid Plant	SO_2	92.0[a]	386.8
		SO_2	4.0 lb/ton, expressed as 100 percent H_2SO_4, and based on a 3-hr average.	

a. Based on a 3-hr average.

94. The permittee shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the maintenance, repair, and replacement (MRR) activities

requested in the application for Permit 0573-AOP-R14 and that is emitted by any emissions unit identified in 40 CFR Part 52.21(r)(6)(i)(b); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change. The permittee shall demonstrate compliance with this condition by complying with Specific Conditions 95 and 96. [Regulation 19, §19.705 and §19.901; 40 CFR Part 52.21(r)(6)(iii); A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311; and 40 CFR Part 70.6]

95. The permittee shall submit a report to the Administrator if the annual emissions, in tons per year, from the maintenance, repair, and replacement (MRR) activities requested in the application for Permit 0573-AOP-R14, exceed the baseline actual emissions (as documented and maintained pursuant to 40 CFR Part 52.21(r)(6)(i)(c)), by a significant amount (as defined in paragraph 40 CFR Part 52.21(b)(23)) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to 40 CFR Part 52.21(r)(6)(i)(c). Such report shall be submitted to the Administrator within 60 days after the end of such year. The report shall contain the following:

    a. The name, address and telephone number of the major stationary source;
    b. The annual emissions as calculated pursuant to 40 CFR Part 52.21(r)(6)(iii); and
    c. Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

    [Regulation 19, §19.705 and §19.901; 40 CFR Part 52.21(r)(6)(v); A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311; and 40 CFR Part 70.6]

96. The permittee shall maintain annual emissions, in tons per year on a calendar basis, of the actual SO_2 emissions from SN-07. The permittee shall use CEMS data when available. When CEMS data is not available, the permittee shall document how the actual emissions were determined, subject to review and approval by the Department. [Regulation 19, §19.705 and §19.901; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; and 40 CFR Part 70.6]

97. The permittee shall not manufacture in excess of 550 tons of 100% sulfuric acid per day through the sulfuric acid plant. These records shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; 40 CFR Part 52, Subpart E; and 40 CFR Part 70.6]

SN-30
Sulfuric Acid Loading

Source Description

The sulfuric acid produced at EDCC is loaded into rail cars or trucks. Loading losses occurring as vapors are displaced to the atmosphere by the liquid being loaded into the rail cars or trucks.

Specific Conditions

98. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on engineering estimates and production. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition 99. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
30	Sulfuric Acid Loading	H_2SO_4	0.03	0.05

99. The permittee shall not load in excess of 200,750 tons of sulfuric acid (100% acid equivalent) per rolling 12-month total. The permittee shall keep records of the sulfuric acid shipped by truck and by rail from the facility. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15^{th} of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

SN-46
Sulfuric Acid Plant Cooling Tower

Source Description

The Sulfuric Acid Plant cooling tower uses a combination of river water and cooling system condensation water to cool the heat generated by the sulfuric acid production process.

Specific Conditions

100. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 103. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
46	Sulfuric Acid Plant Cooling Tower	PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1

101. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 103. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
46	Sulfuric Acid Plant Cooling Tower	PM	0.1	0.1

102. The permittee shall not exceed 20% opacity from the Sulfuric Acid Plant Cooling Tower (SN-46) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-46 is demonstrated by compliance with Specific Condition 103. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

103. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-46 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-46's requirements in Specific Conditions 100, 101, and 102 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

E2 Ammonium Nitrate Plant

SN-05, SN-17, and SN-41
Scrubbers

Source Description

The Ammonium Nitrate E2 Plant Brinks Scrubber (SN-05) controls emissions the E2 prill towers and cooling trains, the intermediate ammonium nitrate storage tanks, and the E2 Plant Chemical Condensate Tank. The E2 Plant Brinks Scrubber (SN-05) is actually two scrubbers, one for each prill tower. EDCC has the ability to shut down one scrubber and the associated prill tower. When one scrubber is shut down, EDCC will not operate the associated prill tower while the scrubber is not operating.

The E2 Plant Chemical Steam Scrubber (SN-41) controls particulate matter and ammonia emissions from the three E2 Plant Neutralizers (formerly SN-02 and SN-03, and a third neutralizer added in 2002), the Ammonium Nitrate Low Concentrator (formerly SN-04), and the E2 Auxiliary Ammonium Nitrate Concentrator (formerly SN-20).

The uncontrolled emissions from SN-05 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for PM_{10}, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limit at this source.

Specific Conditions

104. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-05 is demonstrated by compliance with Specific Conditions 108, 109, 110, 111, and 112. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05	Ammonium Nitrate E2 Brinks Scrubber	PM_{10} $PM_{2.5}$	2.5 2.5	10.9 10.9
06	E2 Ammonium Nitrate Prill Tower Fans	Exhausts from Prill Towers and Cooling Trains are routed to SN-05		
17	E2 HDAN Plant Cooling Train			

105. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-05 is demonstrated by compliance with Specific Conditions 107, 108, 109, 110, 111, and 112. Compliance with the emission limits for SN-41 is demonstrated by compliance with Specific Conditions 109, 111, 111, and 117. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
05	Ammonium Nitrate E2 Brinks Scrubber	NH_3 PM	8.50 2.5	37.30 10.9
06	E2 Ammonium Nitrate Prill Tower Fans	Exhausts from Prill Towers and Cooling Trains are routed to SN-05		
17	E2 HDAN Plant Cooling Train			
41	E2 Plant Chemical Steam Scrubber	NH_3	10.00	43.80

106. The permittee shall not exceed 5% opacity from SN-05 and 5% opacity from SN-41 as measured by EPA Reference Method 9. Compliance with the opacity limits set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

107. The permittee shall have a third party annually stack test the NH_3 emissions from SN-05 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using Test method CTM-027 or an equivalent method approved by the Department shall be used for Ammonia. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-05, 90% rated capacity is defined as:

   a. The 90% of the rated capacity of the prill towers will be on an ammonium nitrate production basis.
   b. The product exit temperature at the prill towers at the time of test must be less than 275°F.

   [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

108. The permittee shall have a third party stack test the PM, PM_{10}, and $PM_{2.5}$ emissions from SN-05 within 180 days after completion of the Expansion Project, and once every 12 months thereafter. Analysis for SN-05 shall be conducted using a method approved in advance by the Department. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. The rated capacity of the

E2 Plant Prill Tower Process rate is defined as 60.0 tons/hr. For SN-05, 90% of rated capacity is defined as:

a. The 90% of the rated capacity of the prill towers will be on an ammonium nitrate production basis.
b. The product exit temperature at the prill towers at the time of test must be less than 275°F.

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

109. The permittee shall not manufacture in excess of 60.0 tons per hour of ammonium nitrate prill through the E2 Ammonium Nitrate Plant. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

110. The permittee shall not manufacture in excess of 525,600 tons of ammonium nitrate prill through the E2 Ammonium Nitrate Plant during any consecutive 12-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

111. The permittee shall keep records of the ammonium nitrate prill production in the E2 Ammonium Nitrate Plant as specified in Specific Conditions 109 and 110. These records shall contain the production for each hour as specified in Specific Condition 109, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

112. The Plant Brinks Scrubber (SN-05) and the E2 Plant Chemical Steam Scrubber (SN-41) shall be kept in good working condition at all times. SN-05 shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-05 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parametric exceedance, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be made available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable.

SN	Description	Parameter	Units	Operation Limits
05	E2 Plant Brinks Scrubber	Scrubber Liquid Flow Rate for Each Scrubber	gal/min	225 (minimum)
		Gas Pressure Drop Across Unit for Each Scrubber	in. H_2O	2.5 (minimum)
		pH	-	0.5 - 6.0

[Regulation 18, §18.1004 and A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311]

113. The permittee shall operate, maintain, and submit reports for the continuous monitoring device for SN-41, as required by Specific Condition 117, in accordance with all applicable requirements of ADEQ CEMS Conditions, located in Appendix H of this permit. The applicable requirements of ADEQ CEMS Conditions include, but are not limited to, the following:

  a. The stack gas sampling system at SN-41 shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.
  b. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.
  c. The permittee shall maintain records of the occurrence and duration of startup/shutdown, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of SN-41 which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.
  d. The permittee shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.
  e. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.
  f. The permittee must maintain on site a file of the continuous monitored data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

g. The permittee shall develop and implement a Quality Assurance/Quality Control (QA/QC) plan within 90 days of permit issuance, and shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability. The permittee must keep a copy of the QA/QC Plan at the source's location and retain all previous versions of the QA/QC Plan for five years.

h. The submitted QA/QC plan shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

i. A back-up monitor may be placed on SN-41 to minimize monitor downtime. This back-up sampling and monitoring system is subject to the same QA/QC procedure and practices as the primary sampling and monitoring system. When the primary sampling and monitoring system goes down, the back-up sampling and monitoring system may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up sampling and monitoring system is placed in service, these records shall include at a minimum the reason the primary sampling and monitoring system is out of service, the date and time the primary sampling and monitoring system was out of service and the date and time the primary sampling and monitoring system was placed back in service.

[Regulation 19, §19.705 and §19.304; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

114. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the emission limits for SN-41 is demonstrated by compliance with Specific Conditions 109, 110, 111, 113, 115, 116, and 117. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
41	E2 Plant Chemical Steam Scrubber	PM PM_{10} $PM_{2.5}$	13.8 (daily 24-hr average)	14.6
		PM PM_{10} $PM_{2.5}$	3.4 (30-day rolling average)	

115. The 30-day rolling average PM_{10} emissions from SN-41 shall not exceed 0.054 pound per ton of ammonium nitrate produced at the neutralizers. Compliance is demonstrated by compliance with the PM_{10} testing requirement of Specific Condition 117. [Regulation 19, §19.901 and 40 CFR Part 52 Subpart E]

116. The daily 24-hour average PM_{10} emissions from SN-41 shall not exceed 0.223 pound per ton of ammonium nitrate produced at the neutralizers. Compliance is demonstrated by compliance with the PM_{10} testing requirement of Specific Condition 117. [Regulation 19, §19.901 and 40 CFR Part 52 Subpart E]

117. The permittee shall continue to conduct continuous sampling of the stack gas at SN-41 to produce two 12-hr composite samples each day to demonstrate compliance with the limits in Specific Conditions 114 and 116. The permittee shall maintain a 30-day rolling average of the PM_{10} emissions at SN-41 to demonstrate compliance with the limits in Specific Conditions 114 and 115.

Each 12-hour composite sample shall be analyzed using Method EDCC-330.2 (to determine ammonia concentration) and EPA Method 300.0 "Determination of Inorganic Anions by Ion Chromatography" (to determine nitrate concentration). EDCC's analysis procedure for ammonia shall be consistent with Method 4500-NH_3 from "Standard Methods for the Examination of Water and Wastewater, 19th Edition". The data from the analyses shall be entered into an Excel spreadsheet on a daily basis to calculate the mass concentrations of ammonia (as NH_3) and condensable particulate (as NH_4NO_3) in the vapor stream leaving SN-41. Total vapor flow from process equipment controlled by SN-41 (i.e., Auxiliary Concentrator, E2 Low Concentrator, Fresh Neutralizer, Off-Gas Neutralizer, and the #4 Neutralizer) shall be assumed to be at maximum rates for initial calculations/compliance demonstration purposes. Should spreadsheet results indicate an exceedance of the permitted rate for ammonia/particulate matter, EDCC shall calculate the actual total vapor flow rate by mass balance around the operations that feed vapors to SN-41 to verify compliance, based on the following:

- The vapor stream from the Auxiliary Concentrator will be considered to be at its maximum rate if the unit is in operation.
- The vapor stream from the Low Concentrator will be calculated based on the measured prill production rate and solution concentrations.
- Vapor flow from the neutralizers will be calculated based on the acid and ammonia feed rates and the acid and product solution concentrations.

The permittee shall maintain an emission inventory spreadsheet for particulate matter and ammonia emissions from SN-41. The spreadsheet shall contain each 12-hour composite sample result and shall be used to maintain a daily, 24-hour average result to demonstrate compliance with the lb/hr emission limits and a 12-month rolling total to demonstrate compliance with the annual emission limits. A valid 12-hour period is defined as beginning at 8:00 a.m. and at 8:00 p.m. This information shall be submitted in accordance with General Provision 7.

[Regulation 19, §19.702 and §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

SN-19
E2 Plant Barometric Tower

Source Description

A wooden structure operating similar to a cooling tower is used to create a "barometric leg" for the high concentrator (located at the top of the E2 Plant Prill Tower) to concentrate ammonium nitrate from 95% strength to greater than 99%. The high concentrator operates under a vacuum and non-condensables are pulled through the barometric leg to this dedicated barometric tower (SN-19). The barometric tower uses weak ammonium nitrate (~20%) process water as the circulation media. Particulate matter emissions occur as a result of particulate entrained in the water vapor mist that is emitted (sprayed) from the tower. Ammonia emissions also occur due to the water containing ammonium nitrate in solution.

Specific Conditions

118. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-19 is demonstrated by compliance with Specific Conditions 109, 110, and 111. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
19	E2 Plant Barometric Tower	PM_{10} $PM_{2.5}$	0.5 0.5	1.9 1.9

119. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-19 is demonstrated by compliance with Specific Conditions 109, 110, and 111. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
19	E2 Plant Barometric Tower	PM NH_3	0.5 4.04	1.9 17.70

120. The permittee shall not exceed 15% opacity from SN-19 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-19 is demonstrated by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-28
E2 Plant HDAN Loading

Source Description

E2 Plant HDAN produced at the E2 Plant is loaded in to rail cars or trucks. Particulate matter emissions occur as the HDAN is being loaded into the rail cars or trucks.

Specific Conditions

121. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-28 is demonstrated by compliance with Specific Conditions 109, 110, and 111. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
28	E2 Plant HDAN/LDAN Loading	PM_{10} $PM_{2.5}$	0.1 0.1	0.1 0.1

122. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-28 is demonstrated by compliance with Specific Conditions 109, 110, and 111. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
28	E2 Plant HDAN/LDAN Loading	PM	1.2	5.3

123. The permittee shall not exceed 10% opacity from SN-28 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-28 is demonstrated by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-34
E2 Plant Solution Reactor

Source Description

A 35% nitric acid/magnesium oxide solution is created by reacting 56% nitric acid with magnesium oxide through agitation. Approximately 0.5% of the magnesium oxide is contained in the final ammonium nitrate product. Each batch takes two hours to make 2.905 tons of nitric acid/magnesium oxide solution. This solution reactor, which does not contain any pollution control equipment, has the capability of producing twelve batches of E2 solution a day while the E2 Ammonium Nitrate Plant is running at its maximum rate. The solution leaves the reactor, where it is filtered to remove any excess magnesium oxide and other trace particulates, and is stored in a heated tank as 35% solution. The solution is pumped to the inlet of the Low Concentrator.

Specific Conditions

124. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on maximum capacity. The tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 109, 110, and 111. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
34	E2 Plant Solution Reactor	PM_{10} $PM_{2.5}$	1.1 1.1	4.5 4.5

125. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on maximum capacity. The tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 109, 110, and 111. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
34	E2 Plant Solution Reactor	PM	1.1	4.5

126. The permittee shall not exceed 20% opacity from SN-34 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-34 is demonstrated by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

KT Ammonium Nitrate Plant

SN-14
LDAN Prill Tower

Source Description

To be sold in final product form, LDAN at the KT Plant is prilled in a prilling tower. A 97% ammonium nitrate solution is mixed with a proprietary additive in a head tank. The prilling operation is accomplished by dispersing the ammonium nitrate solution downward in the tower through a spray nozzle. Long residence times and low air rates contribute to the production of high quality prills, which generate lower particle fines and therefore, lower particulate matter emissions. Four fans control the temperature of the prills leaving the bottom of the prilling tower. This air cools and solidifies the ammonium nitrate droplets into solid prills. The air stream and entrained particles are vented to a Brinks scrubber (SN-14).

The uncontrolled emissions from SN-14 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for PM_{10}, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limit at this source.

Specific Conditions

127. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 45.0 tons per hour of ammonium nitrate production. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 130, 131, 132, 133, and 134. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
14	KT LDAN Prill Tower	PM_{10} $PM_{2.5}$	1.2 1.2	5.0 5.0

128. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 45.0 tons per hour of ammonium nitrate production. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 130, 131, 132, 133, and 134. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
14	KT LDAN Prill Tower	PM	1.2	5.0

129. The permittee shall not exceed 15% opacity from SN-14 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-14 is demonstrated by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

130. The permittee shall not manufacture in excess of 45.0 tons per hour of ammonium nitrate through the KT Ammonium Nitrate Plant. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311 and 40 CFR 70.6]

131. The permittee shall not manufacture in excess of 394,200 tons of ammonium nitrate per rolling 12-month total through the KT Ammonium Nitrate Plant. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311 and 40 CFR 70.6]

132. The permittee shall keep records of the ammonium nitrate production manufactured in the KT Ammonium Nitrate Plant as specified in Specific Conditions 130 and 131. These records shall contain the production for each hour as specified in Specific Condition 130, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

133. The permittee shall have a third party stack test the PM, PM_{10}, and the $PM_{2.5}$ emissions from SN-14 within 180 days after installation of the new Brinks Scrubber, and every 12 months thereafter. The permittee shall not exceed 0.085 mg/acf of particulate matter emissions from SN-14. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The stack test shall be performed using EPA Reference Method 201A or 5, EPA Reference Method 202, and a method approved in advance by the Department. The permittee shall maintain the approved method with the permit. By using Method 5 for PM_{10}, the facility will assume all collected particulate is PM_{10}. PM_{10} emission rates measured during this testing shall be less than the permitted emission rates specified in Specific Condition 127. This unit shall be operated at 90% or more of maximum capacity when the stack test is performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at

all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. 90% of maximum capacity is defined as:

a. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
b. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
c. The moisture content of the product exiting the dryer must be less than 0.1%.
d. 90% of the maximum exhaust flow rate (Maximum exhaust flow rate as provided by the facility = 100,000 acfm).

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

134. The KT Plant Brinks Scrubber (SN-14) shall be kept in good working condition at all times. SN-14 shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-14 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parametric exceedance, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be made available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable.

SN	Description	Parameter	Units	Operation Limits
14	KT Plant Brinks Scrubber	Scrubber Liquid Flow Rate for Each Scrubber	gal/min	225 (minimum)
		Gas Pressure Drop Across Unit for Each Scrubber	in. H_2O	2.5 (minimum)
		pH	-	0.5 - 6.0
		Exhaust Flow Rate	acfm	100,000 (maximum)

[Regulation 18, §18.1004; Regulation 19, §19.705; and A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311]

SN-15, SN-18, and SN-21
KT Plant Dryer, Baghouse, and Scrubber

Source Description

Prills exiting the bottom of the KT LDAN Prill Tower (SN-14) are conveyed to a predryer and dryer. The predryer and dryer exhaust air streams are drawn by a common fan concurrent to the direction of the prill and blown to a wet scrubber. The scrubber efficiency is increased by injecting a portion of the scrubbing solution into the fan system. The wet scrubber exhaust, which contains ammonia and particulate matter, is vented directly to the atmosphere through a stack designated as SN-15.

An external coating of high melting point organic material and talc is added to the LDAN to improve the storage and flow of the final product. The talc is stored in an enclosed silo that pneumatically feeds into a bulk talc hopper. Both the silo and the hopper are equipped with a baghouse (SN-18) to minimize particulate matter emissions. The silo baghouse only operates when the talc is being blown into the silo during the unloading of talc when delivered to the plant. The baghouse at the hopper operates when talc is being added to the LDAN. The baghouses do not operate at the same time.

During LDAN production at the KT Plant, ammonium nitrate solution exits a neutralizer and is pumped into a 50 ton solution storage tank. The ammonium nitrate solution (composed of 90% ammonium nitrate and 10% water) is in molten form at this stage in the process. In the storage tank, the ammonium nitrate solution is blended with "recycled" ammonium nitrate solution, which has been concentrated in the auxiliary concentrator. The ammonium nitrate must be concentrated to 97.5% prior to prilling operations. For this to occur, the ammonium nitrate solution is transferred from the 50 ton tank to a dehydrator. The dehydrator air is blown through the solution to remove excess water. The exhaust stream from the dehydrator is directed to the Brinks Scrubber (SN-21) prior to being vented to the atmosphere.

The uncontrolled emissions from SN-15, SN-18, and SN-21 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because it meets the following criteria: (1) the units are subject to emission limitations for PM_{10}, (2) the sources are equipped with a control device, and (3) the units have potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for these sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limits at these sources.

Specific Conditions

135. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 45.0 tons per hour of ammonium nitrate production. Compliance with the emission limits for SN-15 is demonstrated by compliance with Specific Conditions 130, 131, 132, 138, and 0. Compliance with the emission limits for SN-18 is demonstrated by compliance with Specific Conditions 130, 131, 132, and 0. Compliance with the emission limits for SN-21 is demonstrated by compliance with Specific Conditions 130, 131, 132, 139, and 0. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
15	KT Plant Dryer	PM_{10} $PM_{2.5}$	0.8 0.8	3.2 3.2
18	KT Plant Clay Baghouse	PM_{10} $PM_{2.5}$	1.5 1.5	1.9 1.9
21	KT Plant Brinks Scrubber	PM_{10} $PM_{2.5}$	0.4 0.4	1.5 1.5

136. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 45.0 tons per hour of ammonium nitrate production. Compliance with the emission limits for SN-15 is demonstrated by compliance with Specific Conditions 130, 131, 132, 140, and 0. Compliance with the emission limits for SN-18 is demonstrated by compliance with Specific Conditions 130, 131, 132, and 0. Compliance with the emission limits for SN-21 is demonstrated by compliance with Specific Conditions 130, 131, 132, 140, and 0. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
15	KT Plant Dryer	NH_3 PM	27.00 0.8	118.26 3.2
18	KT Plant Clay Baghouse	PM	1.5	1.9
21	KT Plant Brinks Scrubber	NH_3 PM	45.00 0.4	197.10 1.5

137. The permittee shall not exceed 5% opacity from SN-18, 10% opacity from SN-21, and 20% opacity from SN-15, as measured by EPA Reference Method 9. Compliance with the opacity limits set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

138. The permittee shall have a third party stack test the PM, PM_{10}, and the $PM_{2.5}$ emissions from SN-15 within 180 days after completion of the Expansion Project, and once every 12 months thereafter. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The permittee shall use EPA Reference Method 201A or 5, and EPA Reference Method 202. By using Method 5 for PM_{10}, the facility will assume all collected particulate is PM_{10}. PM_{10} emission rates measured during this testing shall be less than the permitted emission rates specified in Specific Condition 135. These units shall be operated at 90% or more of maximum capacity when the stack tests are performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-15, 90% of maximum capacity is defined as:

a. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
b. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
c. The moisture content of the product exiting the dryer must be less than 0.1%.
d. 90% of the maximum exhaust flow rate (Maximum exhaust flow rate as provided by the facility = 65,000 acfm).

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

139. The permittee shall have a third party stack test the PM, PM_{10}, and the $PM_{2.5}$ emissions from SN-21 within 180 days after completion of the Expansion Project, and once every 12 months thereafter. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The stack test shall be performed using EPA Reference Method 201A or 5, EPA Reference Method 202, and a method approved in advance by the Department. The permittee shall maintain the approved method with the permit. By using Method 5 for PM_{10}, the facility will assume all collected particulate is PM_{10}. These units shall be operated at 90% or more of maximum capacity when the stack tests are performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the

permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-21, 90% of maximum capacity is defined as:

a. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
b. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
c. The moisture content of the product exiting the dryer must be less than 0.1%.
d. 90% of the maximum exhaust flow rate (Maximum exhaust flow rate as provided by the facility = 30,000 acfm).

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

140. The permittee shall have a third party annually stack test the NH_3 emissions from SN-21 using a method approved in advance by the Department to capture ammonia, and the NH_3 emissions shall be less than the permitted emission rates specified in Specific Condition 136. The permittee shall maintain the approved method with the permit. For SN-21, if the stack tests pass three consecutive years of annual testing, the permittee shall perform stack test once every three years. If at any time the facility has test results indicating an exceedance of a permitted emission rate at SN-21, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates compliance with the permitted emission rates after three consecutive passing tests, then the facility may return to performing stack testing once every 36 months. The permittee shall have a third party stack test once every 60 months the NH_3 emissions from SN-15 using a method approved in advance by the Department to capture ammonia, and the NH_3 emissions shall be less than the permitted emission rates specified in Specific Condition 136. If at any time the facility has test results indicating an exceedance of a permitted emission rate at SN-15, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The units shall be operated at 90% or more of maximum capacity when the stack tests are performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. The 90% of maximum capacity is defined as:

a. For SN-15, 90% of the maximum capacity during NH_3 testing is defined as:

i. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
ii. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
iii. The moisture content of the product exiting the dryer must be less than 0.1%.
iv. 90% of the maximum exhaust flow rate (Maximum exhaust flow rate as provided by the facility = 65,000 acfm).

b. For SN-21, 90% of maximum capacity during NH_3 testing is defined as:

i. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
ii. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
iii. The moisture content of the product exiting the dryer must be less than 0.1%.
iv. 90% of the maximum exhaust flow rate (Maximum exhaust flow rate as provided by the facility = 30,000 acfm).

[Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

141. The KT Brinks Scrubber (SN-21), the KT Plant Dryer Scrubber (SN-15), and the KT Plant Clay Baghouse (SN-18) shall be kept in good working condition at all times and shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-15, and SN-18, and SN-21 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parameter to be outside the range, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Parameter	Units	Operation Limits
15	KT Plant Dryer Scrubber	Scrubber Liquid Flow Rate	gal/min	225 (minimum)
		Gas Pressure Drop Across Unit	in. H_2O	2.5 (minimum)
		pH	-	0.5 – 6.0
		Exhaust Flow Rate	acfm	65,000 (maximum)
18	KT Plant Baghouse	Gas Pressure Drop	in. H_2O	0.5 - 8.0
21	KT Brinks Scrubber	Scrubber Liquid Flow Rate	gal/min	225 (minimum)
		Gas Pressure Drop Across Unit	in. H_2O	2.5 (minimum)
		pH	-	0.5 – 6.0
		Exhaust Flow Rate	acfm	30,000 (maximum)

SN-27
KT Plant LDAN Loading

Source Description

LDAN produced at the KT Plant is loaded into rail cars or trucks. Particulate emissions occur as the LDAN is being loaded into the rail cars or trucks.

Specific Conditions

142. The permittee shall not exceed the emission rates set forth in the following table. The emission limits are based on maximum capacity. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 130, 131, and 132. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	Lb/hr	tpy
27	KT Plant LDAN Loading	PM_{10} $PM_{2.5}$	0.1 0.1	0.1 0.1

143. The permittee shall not exceed the emission rates set forth in the following table. The emission limits are based on maximum capacity. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 130, 131, and 132. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
27	KT Plant LDAN Loading	PM	0.9	4.0

144. The permittee shall not exceed 10% opacity from SN-27 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-27 is demonstrated by compliance with Plantwide Condition 8. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

SN-63
KT Plant Chemical Steam Scrubber

Source Description

The KT Plant Chemical Steam Scrubber (SN-63) will be installed with the Expansion Projection modification. SN-63 will control particulate matter and ammonia emissions from a new neutralizer being added, as well as emissions from the E2 Prill and AN solution operations. This scrubber will be designed equivalently with SN-41, and SN-41 emission factors are used here for permitting purposes.

Specific Conditions

145. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 148 through 154. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	Tpy
63	KT Plant Chemical Steam Scrubber	PM_{10} $PM_{2.5}$	14.0 (daily 24-hr average)	14.8
		PM_{10} $PM_{2.5}$	3.4 (30-day rolling average)	

146. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 148 through 154. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
63	KT Plant Chemical Steam Scrubber	PM	14.0 (daily 24-hr average)	14.8
		PM	3.4 (30-day rolling average)	
		NH_3	10.19	44.63

147. The permittee shall not exceed 5% opacity from SN-63 as measured by EPA Reference Method 9. Compliance with the opacity limits set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

148. The permittee shall operate, maintain, and submit reports for the continuous monitoring device for SN-63, as required by Specific Condition 154, in accordance with all applicable requirements of ADEQ CEMS Conditions, located in Appendix H of this

permit. The applicable requirements of ADEQ CEMS Conditions include, but are not limited to, the following:

a. The stack gas sampling system at SN-63 shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.
b. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.
c. The permittee shall maintain records of the occurrence and duration of startup/shutdown, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of SN-63 which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.
d. The permittee shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.
e. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.
f. The permittee must maintain on site a file of the continuous monitored data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.
g. The permittee shall develop and implement a Quality Assurance/Quality Control (QA/QC) plan within 90 days of permit issuance, and shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability. The permittee must keep a copy of the QA/QC Plan at the source's location and retain all previous versions of the QA/QC Plan for five years.
h. The submitted QA/QC plan shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.
i. A back-up monitor may be placed on SN-63 to minimize monitor downtime. This back-up sampling and monitoring system is subject to the same QA/QC procedure and practices as the primary sampling and monitoring system. When the primary sampling and monitoring system goes down, the back-up sampling and

monitoring system may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up sampling and monitoring system is placed in service, these records shall include at a minimum the reason the primary sampling and monitoring system is out of service, the date and time the primary sampling and monitoring system was out of service and the date and time the primary sampling and monitoring system was placed back in service.

[Regulation 19, §19.705 and §19.304; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

149. The 30-day rolling average particulate emissions (PM, PM_{10}, and $PM_{2.5}$) from SN-63 shall not exceed 0.054 pound per ton of ammonium nitrate produced at the neutralizers. Compliance is demonstrated by compliance with the particulate emission testing requirement of Specific Condition 154. [Regulation 19, §19.901 and 40 CFR Part 52 Subpart E]

150. The daily 24-hour average particulate emissions (PM, PM_{10}, and $PM_{2.5}$) from SN-63 shall not exceed 0.223 pound per ton of ammonium nitrate produced at the neutralizers. Compliance is demonstrated by compliance with the particulate emission testing requirement of Specific Condition 154. [Regulation 19, §19.901 and 40 CFR Part 52 Subpart E]

151. The permittee shall not manufacture in excess of 62.5 tons per hour of ammonium nitrate through the KT Plant Chemical Steam Scrubber. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

152. The permittee shall not manufacture in excess of 547,500 tons of ammonium nitrate through the KT Plant Chemical Steam Scrubber during any consecutive 12-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

153. The permittee shall keep records of the ammonium nitrate prill production in the E2 Ammonium Nitrate Plant as specified in Specific Conditions 151 and 152. These records shall contain the production for each hour as specified in Specific Condition 151, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

154. The permittee shall continue to conduct continuous sampling of the stack gas at SN-63 to produce two 12-hr composite samples each day to demonstrate compliance with the limits in Specific Conditions 145, 146, and 150. The permittee shall maintain a 30-day

rolling average of the PM_{10} emissions at SN-63 to demonstrate compliance with the limits in Specific Conditions 145 and 149.

Each 12-hour composite sample shall be analyzed using Method EDCC-330.2 (to determine ammonia concentration) and EPA Method 300.0 "Determination of Inorganic Anions by Ion Chromatography" (to determine nitrate concentration). EDCC's analysis procedure for ammonia shall be consistent with Method 4500-NH_3 from "Standard Methods for the Examination of Water and Wastewater, 19th Edition". The data from the analyses shall be entered into an Excel spreadsheet on a daily basis to calculate the mass concentrations of ammonia (as NH_3) and condensable particulate (as NH_4NO_3) in the vapor stream leaving SN-63. Total vapor flow from process equipment controlled by SN-63 shall be assumed to be at maximum rates for initial calculations/compliance demonstration purposes. Should spreadsheet results indicate an exceedance of the permitted rate for ammonia/particulate matter, EDCC shall calculate the actual total vapor flow rate by mass balance around the operations that feed vapors to SN-63 to verify compliance, based on the following:

- The vapor stream from the Auxiliary Concentrator will be considered to be at its maximum rate if the unit is in operation.
- The vapor stream from the Low Concentrator will be calculated based on the measured prill production rate and solution concentrations.
- Vapor flow from the neutralizers will be calculated based on the acid and ammonia feed rates and the acid and product solution concentrations.

The permittee shall maintain an emission inventory spreadsheet for particulate matter and ammonia emissions from SN-63. The spreadsheet shall contain each 12-hour composite sample result and shall be used to maintain a daily, 24-hour average result to demonstrate compliance with the lb/hr emission limits and a 12-month rolling total to demonstrate compliance with the annual emission limits. A valid 12-hour period is defined as beginning at 8:00 a.m. and at 8:00 p.m. This information shall be submitted in accordance with General Provision 7.

[Regulation 19, §19.702 and §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

Ammonia Plant

SN-49
Ammonia Plant Primary Reformer

Source Description

A mixture of natural gas and steam are combined in the primary reformer to convert methane to hydrogen and carbon dioxide. The fuel burned to provide heat for this conversion produces combustion products such as carbon monoxide, mixed oxides of nitrogen, sulfur dioxide, particulate matter and hydrocarbons. These combustion products are exhausted from the primary reformer as SN-49. EDCC will install a Selective Catalytic Reduction (SCR) Unit to reduce NO_x emissions from this source. NO_x control efficiency is estimated at 95% per vendor specifications.

Specific Conditions

155. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 160, 161, and 162. The permittee shall demonstrate compliance with the particulate emission rates by complying with Specific Condition 163. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
49	Ammonia Plant Primary Reformer (824 MMBtu/hr natural gas-fired reformer with SCR)	PM_{10}	3.5	15.2
		$PM_{2.5}$	3.5	15.2
		Lead	0.01	0.01

156. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 158, 160, 161, and 162. [Regulation 19 §19.501 et seq. and §19.901; and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
49	Ammonia Plant Primary Reformer (824 MMBtu/hr natural gas-fired reformer with SCR)	SO_2	0.7	0.5
		VOC	1.2	5.1
		CO	16.0	70.1
		NO_x	10.3	44.8
		CO_2e	96,737.6	423,714.2

157. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 160, 161, and 162, Plantwide Conditions 13 through 42, and Table 3 to 40 CFR Part 63, Subpart DDDDD. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
49	Ammonia Plant Primary Reformer (824 MMBtu/hr natural gas-fired reformer with SCR)	PM	3.5	15.2
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.07	0.27
		Hexane	1.45	6.37
		Mercury	0.01	0.01

158. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the SO_2 emission limits by complying with Specific Condition 164 and Plantwide Condition 9. The permittee shall demonstrate compliance with the VOC emission limits by complying with Specific Condition 164. The permittee shall demonstrate compliance with the CO emission limits by complying with Specific Condition 165. The permittee shall demonstrate compliance with the NO_x emission limits by complying with Specific Condition 167. The permittee shall demonstrate compliance with the CH_4 and CO_2 emission limits by complying with Specific Condition 166. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-49	Ammonia Plant Primary Reformer (824 MMBtu/hr natural gas-fired reformer with SCR)	Opacity	Combustion of natural gas and process off gas (purge gas), and good and efficient combustion practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.61 lb/hr (3-hr average) 0.44 tons per rolling 12 months
		VOC		0.0014 lb/MMBtu (3-hr average) 1.15 lb/hr (3-hr average) 5.05 tons per rolling 12 months

		CO		0.0194 lb/MMBtu (3-hr average) 15.99 lb/hr (3-hr average) 70.02 tons per rolling 12 months
		NO_x	SCR	0.0124 lb/MMBtu (3-hr average) 10.22 lb/hr (3-hr average) 44.75 tons per rolling 12 months
		GHG	Good operating practices	CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 423,714.2 tons per rolling 12 months

159. The permittee shall not exceed 0% opacity from the Ammonia Plant Primary Reformer (SN-49) as measured by EPA Reference Method 9. Compliance with the opacity limit set forth in this Specific Condition will be shown by compliance with Plantwide Condition 8. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

160. The permittee shall not combust in excess 7,076.7 million standard cubic feet of natural gas during any consecutive 12-month period at SN-49. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

161. The permittee shall not manufacture in excess of 511,000 tons per rolling 12-month total of ammonia through the Ammonia Plant Primary Reformer (SN-49). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

162. The permittee shall keep records of the natural gas usage and the ammonia production at the Ammonia Plant Primary Reformer (SN-49) as specified in Specific Conditions 160 and 161. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

163. The permittee shall have a third party annually stack test the PM, PM_{10}, and $PM_{2.5}$ emissions and opacity, from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using EPA Reference Method 5 and 202 for PM, EPA Reference Method 201A and 202 for PM_{10} and $PM_{2.5}$, and EPA Reference Method 9 for opacity. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

164. The permittee shall have a third party annually stack test the SO_2 and VOC emissions from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack tests shall be performed using EPA Reference Method 6C for SO_2 and EPA Reference Method 25A for VOC. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

165. The permittee shall have a third party annually stack test the CO emissions from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days

after initial startup, and once every 12 months thereafter. The stack test shall be performed using EPA Reference Method 10 for CO. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

166. The permittee shall have a third party stack annually test the Methane (CH_4) and Carbon Dioxide (CO_2) emissions from SN-49 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using EPA Reference Method 18 for Methane and EPA Reference Method 3A for CO_2. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 18, §18.1002; Regulation 19, §19.702; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

167. The permittee shall install, calibrate, maintain, and operate a CEMS to monitor NO_x and N_2O emissions from the Ammonia Plant Primary Reformer (SN-49). The NO_x monitor shall be operated in accordance with the ADEQ CEMS conditions and shall be operated at all times including during startup and shutdown. Compliance will be demonstrated on

a rolling 3-hour average. [Regulation 19, §19.703; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

168. The permittee shall comply with the following table from 40 CFR Part 63, Subpart DDDDD:

Table 3 to Subpart DDDDD of 40 CFR Part 63 – Work Practice Standards

If your unit is . . .	You must meet the following . . .
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

SN-50
Ammonia Plant Condensate Steam Stripper

Source Description

Carbon monoxide is formed as a byproduct in the catalytic steam reforming process. After cooling, the carbon monoxide and water contained in the synthesis gas are converted to carbon dioxide and hydrogen in the High Temperature and Low Temperature Shift Converters. Unreacted steam is condensed and separated from the synthesis gas in a knockout drum, and the condensate is flashed in the Condensate Steam Stripper (SN-50) to remove volatile gases. The residual condensate may be returned to the boiler or reused in another portion of the process.

Specific Conditions

169. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 160, 161, 162, and 171. [Regulation 19, §19.501 et seq. and §19.901; and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
50	Ammonia Plant Condensate Steam Stripper	VOC	5.9[a]	25.6
		CO_2e	396.7	1,737.4

a. 24-hr average

170. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 160, 161, and 162. The permittee shall demonstrate compliance with the Methanol emission limits by complying with Specific Condition 174. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
50	Ammonia Plant Condensate Steam Stripper	NH_3	0.56	2.45
		Methanol	4.90	21.46

171. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the VOC emission limits by complying with Specific Condition 172. The permittee shall demonstrate compliance with the CO_2 emission limits by complying with Specific Condition 173. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-50	Ammonia Plant Condensate Steam Stripper	VOC	Good and efficient operating practices	0.1 lb/ton of NH_3 produced (24-hr average) 5.83 lb/hr (24-hr average) 25.55 tons per rolling 12 months
		GHG		CO_2 6.8 lb/ton of Ammonia production (24-hr average) CO_2 396.64 lb/hr (24-hr average) CO_2e 1,737.4 tons per rolling 12 months

172. The permittee shall have a third party stack test the VOC emissions from SN-50 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack test shall be performed using EPA Reference Method 25A for VOC. The test shall be conducted over a 24 hour period. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

173. The permittee shall have a third party stack test the CO_2 emissions from SN-50 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack test shall be performed using EPA Reference Method 3A for CO_2. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted

capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

174. The permittee shall have a third party stack test the Methanol emissions from SN-50 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using EPA Reference Method 18 or 25A for Methanol, or another method approved in advance by the Department. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-51
Ammonia Plant CO_2 Regenerator

Source Description

After the carbon monoxide shift, the carbon dioxide is removed from the process gas by sending the synthesis gas through an absorption tower where a methyl diethanolamine/piperazine solution (MDEA) is used to strip the carbon dioxide out of the gas. Carbon dioxide is removed from the MDEA in a stripper column (CO_2 Regenerator), where it is vented to the atmosphere (SN-51).

Specific Conditions

175. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 160, 161, 162, and 177. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
51	Ammonia Plant CO_2 Regenerator	VOC	33.7	147.4
		CO	1.2	5.2
		CO_2e	146,262.6	640,669.2

176. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 160, 161, and 162. The permittee shall demonstrate compliance with the Ammonia emission limits by complying with Specific Condition 180. The permittee shall demonstrate compliance with the Methanol emission limits by complying with Specific Condition 181. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
51	Ammonia Plant CO_2 Regenerator	NH_3	2.63	11.53
		Methanol	27.79	121.73

177. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the VOC emission limits by complying with Specific Condition 178. The permittee shall demonstrate compliance with the CO emission limits by complying with Specific Condition 179. The permittee shall demonstrate compliance with the CO emission limits by complying with Specific Condition 182. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-51	Ammonia Plant CO_2 Regenerator	VOC	Good and efficient operating practices	0.106 lb/ton of NH_3 produced (3-hr average) 33.64 lb/hr (3-hr average) 147.35 tons per rolling 12 months
		CO		0.02 lb/ton of NH_3 produced (3-hr average) 1.17 lb/hr (3-hr average) 5.11 tons per rolling 12 months
		GHG		CO_2 2,507.5 lb/ton of NH_3 produced (3-hr average) 146,262.6 lb/hr CO_2 CO_2/CO_2e 640,669.2 tons per rolling 12 months

178. The permittee shall have a third party stack test the VOC emissions from SN-51 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack test shall be performed using EPA Reference Method 25A for VOC. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

179. The permittee shall have a third party stack test the CO emissions from SN-51 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack test shall be performed using EPA Reference Method 10 for CO. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted

capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

180. The permittee shall have a third party stack test the Ammonia (NH_3) emissions from SN-51 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. The stack test shall be performed using EPA Reference Method 320 for Ammonia, or another method approved in advance by the Department. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

181. The permittee shall have a third party stack test the Methanol emissions from SN-51 within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup, and once every 12 months thereafter. The stack test shall be performed using EPA Reference Method 18 or 25A for Methanol, or another method approved in advance by the Department. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

182. The permittee shall install, calibrate, maintain, and operate a CEMS to monitor CO_2 emissions from the Ammonia Plant CO_2 Regenerator (SN-51). The CO_2 monitor shall be operated in accordance with the ADEQ CEMS conditions and shall be operated at all

times including during startup and shutdown. Compliance will be demonstrated on a rolling 3-hour average. [Regulation 19, §19.703; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-52
Ammonia Plant Cooling Tower

Source Description

The Ammonia Plant Cooling Tower (SN-52) provides non-contact cooling water to the Ammonia Plant process equipment. Particulate matter is emitted during operation of the cooling tower.

Specific Conditions

183. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 186. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
52	Ammonia Plant Cooling Tower	PM_{10}	0.5	2.1
		$PM_{2.5}$	0.5	2.1

184. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 186. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
52	Ammonia Plant Cooling Tower	PM	0.5	2.1

185. The permittee shall not exceed 5% opacity from the Ammonia Plant Cooling Tower (SN-52) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-52 is demonstrated by compliance with Specific Condition 186. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

186. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-52 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-52's requirements in Specific Conditions 183, 184, and 185 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-53, SN-56, and SN-57
Ammonia Plant Ammonia Vent Flare, Ammonia Plant Process SSM Flare, Ammonia Storage Flare

Source Description

EDCC will pipe ammonia-containing vent streams to a separate flare, SN-53. Two synthesis gas process streams will discharge to this flare in the event of a synthesis loop depressuring for shut-down or maintenance. This gas contains NH_3, CH_4, and inerts. In addition, there will be an ammonia vent tied to this flare that will only vent in the case of emergency. This stream will contain only NH_3. When the unit is not flaring process gas, it burns natural gas as purge to maintain a positive pressure in the flare tip while not in use. Maximum hourly emissions consist of emissions from the pilot plus either the process gas flaring, emergency ammonia flaring or purge combustion, depending upon the pollutant. Annual emissions include the combined contributions of combusting natural gas for the pilot and purge as well as the process gas combustion. The annual average is conservative in that it assumes continuous annual purge gas combustion as well as maximum hours of flare operation. This is done to insure maximum potential values of each pollutant. When actually flaring process gas or emergency ammonia, the flare does not burn the purge gas.

With this modification application, EDCC proposes to install a natural gas fired ammonia plant process flare (SN-56) to burn process gas exhausted during start-ups, shutdowns, or as otherwise needed for maintenance purposes. During startup, each part of the ammonia production process is brought on line in succession. As each section is prepared for operation, the equipment may vent to the atmosphere since the succeeding equipment is not ready to receive feed. These vents release for short periods during startups and will be controlled with the SN-56 flare. This gas contains CO, CO_2, and CH_4 in addition to inert gases. All streams containing ammonia are piped separately and controlled via SN-53. When the unit is not flaring process gas, it burns natural gas as purge to maintain a positive pressure in the flare tip while not in use. Maximum hourly emissions consist of emissions from the pilot plus either the flaring or purge combustion, depending upon the pollutant. Annual emissions include the combined contributions of combusting natural gas for the pilot and purge as well as the process gas combustion. The annual average is conservative in that it assumes continuous annual purge gas combustion as well as maximum hours of flare operation. This is done to insure maximum potential values of each pollutant. When actually flaring process gas, the flare does not burn the purge gas.

EDCC proposes to install a natural gas fired flare (SN-57) to reduce ammonia emissions from ammonia storage during depressurization of the refrigeration system, during SSM events, or as otherwise needed.

Specific Conditions

187. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 194 through 0. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
53	Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)	PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		Lead	0.01	0.01
56	Ammonia Plant Process SSM Flare	PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		Lead	0.01	0.01
57	Ammonia Storage Flare	PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		Lead	0.01	0.01

188. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 194 through 0. [Regulation 19 §19.501 et seq. and §19.901; and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
53	Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)	SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.1	0.4
		NO_x	792.1	6.9
		CO_2e	7,304.2	719.9
56	Ammonia Plant Process SSM Flare	SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	156.1	39.4
		NO_x	0.1	0.5
		CO_2e	18,787.9	5,179.8

SN	Description	Pollutant	lb/hr	tpy
57	Ammonia Storage Flare	SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.1	0.1
		NO_x	10.1	43.9
		CO_2e	20.6	90.0

189. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 194 through 0. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
53	Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)	PM	0.1	0.1
		NH_3	1,584.05	9.73
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.01	0.01
		Mercury	0.01	0.01
56	Ammonia Plant Process SSM Flare	PM	0.1	0.1
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.01	0.01
		Mercury	0.01	0.01

SN	Description	Pollutant	lb/hr	tpy
57	Ammonia Storage Flare	PM	0.1	0.1
		NH_3	40.00	175.20
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.01	0.01
		Mercury	0.01	0.01

190. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 193 through 0. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-53	Ammonia Plant Ammonia Vent Flare (0.26 MMBtu/hr total from 4 pilots)	Opacity	Combustion of Natural gas and Good Combustion Practice	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.00077 lb/hr (3-hr average) 0.0034 tons per rolling 12 months
		VOC		0.0054 lb/MMBtu (3-hr average) 0.0057 lb/hr (3-hr average) 0.025 tons per rolling 12 months
		CO		0.082 lb/MMBtu (3-hr average) 0.087 lb/hr (3-hr average) 0.38 tons per rolling 12 months
		NO_x		0.098 lb/MMBtu (3-hr average) from pilot 792.03 lb/hr (3-hr average based on 0.5% conversion of NH_3 to NO_x 6.9 tons per rolling 12 months
		GHG		CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 719.9 tons per rolling 12 months

191. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 193 through 0. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-56	Ammonia Plant Process SSM Flare	Opacity	Combustion of Natural gas and Good Combustion Practice	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.0007 lb/hr (3-hr average) 0.0031 tons per rolling 12 months
		VOC		0.0054 lb/MMBtu (3-hr average) 0.0051 lb/hr (3-hr average) 0.023 tons per rolling 12 months
		CO		0.082 lb/MMBtu (3-hr average) from pilot 156.10 lb/hr (3-hr average based on 98% control of process gas 39.36 tons per rolling 12 months
		NO_x		0.098 lb/MMBtu (3-hr average) 0.093 lb/hr (3-hr average) 0.41 tons per rolling 12 months
		GHG		CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 5,179.8 tons per rolling 12 months

192. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 193 through 0. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-57	Ammonia Storage Flare	Opacity	Combustion of natural gas, and good and efficient operating practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.00015 lb/hr (3-hr average) 0.00056 tons per rolling 12 months
		VOC		0.0054 lb/MMBtu (3-hr average) 0.0011 lb/hr (3-hr average) 0.0041 tons per rolling 12 months
		CO		0.082 lb/MMBtu (3-hr average) 0.017 lb/hr (3-hr average) 0.063 tons per rolling 12 months
		NO_x		0.098 lb/MMBtu (3-hr average) from pilot 10.02 lb/hr (3-hr average based on 0.5% conversion of NH_3 to NO_x) 43.88 tons per rolling 12 months
		GHG		CO_2 117 lb/MMBtu (3-hr average) CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 89.99 tons per rolling 12 months

193. The permittee shall not exceed 0% opacity from SN-53, SN-56, and SN-57 as measured by EPA Reference Method 22. Compliance with the opacity limit for SN-56 is

demonstrated by compliance with Specific Conditions 194 and 202. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

194. The permittee shall burn only pipeline quality natural gas as fuel for Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57). [Regulation 19, §19.705, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

195. The permittee shall not combust in excess 9.0 million standard cubic feet of natural gas during any consecutive 12-month period at SN-53. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

196. The permittee shall not combust in excess 8.2 million standard cubic feet of natural gas during any consecutive 12-month period at SN-56. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

197. The permittee shall not combust in excess 1.5 million standard cubic feet of natural gas during any consecutive 12-month period at SN-57. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

198. The permittee shall maintain monthly records of the amount of natural gas combusted each month to demonstrate compliance with Specific Conditions 195, 196, and 197. Records shall be updated by the 15th day of the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A 12-month rolling average and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and §19.901 et seq. and 40 CFR Part 52, Subpart E]

199. The permittee shall not operate the Ammonia Plant Ammonia Vent Flare (SN-53) in excess of three (3) hours during any consecutive 24-hour period. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

200. The permittee shall maintain daily records of the hours of operation at SN-53 to demonstrate compliance with Specific Condition 199. These records shall contain the hours of operations as specified in Specific Condition 199, and shall contain each month's total and a rolling total for the previous 12 months. Records shall be updated by the 15th day of the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A 12-month rolling average and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and §19.901 et seq. and 40 CFR Part 52, Subpart E]

201. The permittee shall maintain records to demonstrate compliance with Specific Conditions 187, 188, and 189. These records shall include the simultaneous gas flow to the flare in standard cubic feet per minute (scfm). The permittee shall monitor the gas flow to the flare continuously and shall be recorded once every 15 minutes. Electronic or paper hourly records shall be maintained of the flow rate to the flare. The permittee shall update these records by the 15th day of the month following the month to which the records pertain. These records shall be maintained on site and shall be provided to Department personnel upon request. These records shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004, Regulation 19, §19.705, 40 CFR Part 52, Subpart E and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

202. The permittee shall conduct weekly observations of the opacity at SN-53, SN-56, and SN-57 and keep a record of these observations. Each of the flares (SN-53, SN-56, and SN-57) shall be designed for and operated with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours. EPA Reference Methods 22 shall be used to determine compliance with the visible emission provisions of the flare. If the permittee detects visible emissions in excess of their permitted limit, the permittee must immediately take action to identify and correct the cause of the visible emissions. After implementing the corrective action, the permittee must document that the source complies with the visible emissions requirements. The permittee shall maintain records of the cause of the visible emissions and the corrective action taken. The permittee must keep these records onsite and make them available to Department personnel upon request. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

203. The permittee must operate the Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57) pilot flames within the design limitations and manufacturer's specifications. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

204. The Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57) must have a flame present at all times of operation. The presence of a flare pilot light shall be monitored continuously using a thermocouple, an ultraviolet sensor or any other equivalent device to detect the presence of a flame. [Regulation 19, §19.303, §19.304, §60.18(b) through (f), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

205. The permittee shall install and operate alarm system at the Ammonia Plant Ammonia Vent Flare (SN-53), the Ammonia Plant Process SSM Flare (SN-56), and the Ammonia Storage Flare (SN-57) to notify the operator of the presence of a pilot flame or other possible flare malfunction. The permittee shall perform monthly visual confirmation of the pilot lights, semi-annually remove the strainer and check for debris, and annual test fire to ensure pilot light. The permittee shall maintain logs of all flare inspection and maintenance activities. These logs shall be kept on site, in accordance with General Provision 7, and made available to Department personnel upon request. [Regulation 19, §19.702; 40 CFR 52, Subpart E; and 40 CFR Part 64]

SN-54
Ammonia Plant Start-up Heater

Source Description

This 38 MMBtu/hr start-up heater is required to bring the ammonia plant up to production. The heater is used to start-up the ammonia synthesis unit operation. This natural gas fired heater is used infrequently and only during plant start-up.

Specific Conditions

206. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 211, 212, and 213. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
54	Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)	PM_{10}	0.3	0.1
		$PM_{2.5}$	0.3	0.1
		Lead	0.01	0.01

207. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 211, 212, and 213. [Regulation 19 §19.501 et seq. and §19.901 et seq.; and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
54	Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)	SO_2	0.1	0.1
		VOC	0.2	0.1
		CO	0.8	0.2
		NO_x	2.3	0.6
		CO_2e	4,461.3	1,115.4

208. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 211, 212, and 213, and Plantwide Conditions 13 through 42. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
54	Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)	PM	0.3	0.1
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.08	0.02
		Mercury	0.01	0.01

209. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 210, 211, 212, and 213. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
54	Ammonia Plant Start-up Heater (38 MMBtu/hr natural gas-fired)	Opacity	Combustion of Natural gas and Good Combustion Practice	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.03 lb/hr (3-hr average) 0.007 tons per rolling 12 months
		VOC		0.002 lb/MMBtu (3-hr average) 0.19 lb/hr (3-hr average) 0.048 tons per rolling 12 months
		CO		0.01 lb/MMBtu (3-hr average) 0.76 lb/hr (3-hr average) 0.19 tons per rolling 12 months
		NO_x	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.06 lb/MMBtu (3-hr average) 2.28 lb/hr (3-hr average) 0.57 tons per rolling 12 months

		GHG	Good operating practices	CO_2 117 lb/MMBtu CH_4 0.0022 lb/MMBtu N_2O 0.00022 lb/MMBtu CO_2e 1,115.31 tons per rolling 12 months

210. The permittee shall not exceed 0% opacity from the Ammonia Plant Start-up Heater (SN-54) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-54 shall be demonstrated by compliance with Specific Condition 211. [Regulation 18, §18.501; Regulation 19, §19.901; and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

211. The permittee shall burn only pipeline quality natural gas in SN-54. [Regulation 19, §19.705, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

212. The permittee shall not combust in excess 18.63 million standard cubic feet of natural gas during any consecutive 12-month period at SN-54. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

213. The permittee shall maintain monthly records of the amount of natural gas combusted each month to demonstrate compliance with Specific Condition 212. Records shall be updated by the 15th day of the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A twelve month rolling average and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and §19.901 et seq. and 40 CFR Part 52, Subpart E]

SN-55
Ammonia Plant Fugitives

Source Description

Fugitive leaks of process gas/liquid containing ammonia occur during normal operation from process equipment components (i.e., valves, flanges, pump seals, etc.).

Specific Conditions

214. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 161, and 162. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	Tpy
55	Ammonia Plant Fugitives	NH_3	15.42	67.54

Mixed Acid Plant

SN-44
Mixed Acid Plant Scrubber

Source Description

EDCC manufactures mixed acid by mixing ≤ 30% oleum (concentrated sulfuric acid) and/or 98% sulfuric acid with 98% nitric acid. The ≤ 30% oleum is purchased from a vendor and delivered to EDCC by railcar or tanker truck, while the 98% sulfuric acid will come from EDCC's Sulfuric Acid Plant, and the 98% nitric acid will come from EDCC's Nitric Acid Plant. The manufactured mixed acid is stored in the product storage tank or the mixing tank until it is loaded into a railcar or tanker truck. Air emissions from the tanks, the unloading of oleum, and the loading/unloading of the mixed acid into tank cars and/or trucks will be routed to the scrubber (SN-44) prior to being released to the atmosphere.

This scrubber is not subject to CAM because the scrubber is not used to control the NO_x emissions from this source.

Specific Conditions

215. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Conditions 218 through 225. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
44	Mixed Acid Plant Scrubber	NO_x	0.4	1.7

216. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 218 through 225. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
44	Mixed Acid Plant Scrubber	SO_3	0.04	0.18
		H_2SO_4	0.04	0.18
		HNO_3	0.19	0.83

217. The permittee shall not exceed 20% opacity from SN-44 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-44 is demonstrated by compliance with Plantwide Condition 8. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

218. The permittee shall offload no more than 45.0 tons of oleum per hour into the Oleum Storage Tank. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

219. The permittee shall offload no more than 394,200 tons of oleum into the Oleum Storage Tank per consecutive 12-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

220. The permittee shall not use Oleum in excess of 30% in strength (SO_3 concentration). [Regulation 19, §19.705, A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311, and 40 CFR 70.6]

221. The permittee shall not produce more than 25.0 tons of mixed acid per hour. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

222. The permittee shall not produce more than 219,000 tons of mixed acid per consecutive 12-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

223. The permittee shall maintain monthly records of the amount of Oleum offloaded into the Oleum Storage Tank, the percent strength of the oleum, and the amount of mixed acid produced as specified in Specific Conditions 218 through 222. These records shall contain the hourly records specified in Specific Conditions 218 and 221, the oleum strength specified in Specific Condition 220, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705, A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311, and 40 CFR 70.6]

224. The permittee shall have a third party stack test SN-44 once every five years for HNO_3, H_2SO_4, SO_3, and NO_x emissions using an approved method, and the emissions shall be less than the hourly limit specified in Specific Conditions 215 and 216. Upon failure of a stack test, the permittee shall stack test annually until two consecutive years are below the permitted emission rates. During stack testing, the mixed acid plant shall be operating at a rate greater than or equal to 90% capacity. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

225. The Mixed Acid Scrubber shall be kept in good working condition at all times. The following monitoring parameters for SN-44 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data recorded once per 12-hour shift when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parameter to be outside the range, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and made available to Department personnel upon request. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Parameter	Units	Operation Limits
44	Mixed Acid Plant Scrubber	Scrubber Liquid Flow Rate	gal/min	5.0 (minimum)
		Gas Pressure Drop Across Unit	in. H_2O	10 - 35
		Scrubber liquid pH	-	0.5 – 7.5

Natural Gas Fired Boiler

SN-61
Natural Gas Fired Start-up Boiler

Source Description

A 240 MMBtu/hr natural gas fired Startup Boiler (SN-61) is used to supply steam throughout the multi-plant facility startup operations and for process heating purposes when excess steam generated from the operating plants is not available. Emissions from the boiler occur due to the combustion of natural gas. This boiler is being permitted as a high turndown rate (10:1) boiler. The turndown rate represents the maximum firing rate of the burners compared to the lowest controllable fire rate at which the boiler can operate. This turndown rate is necessary to EDCC's operations due to the high variability in steam demand at the facility.

Operating Scenario # 1

Specific Conditions

226. The permittee shall comply with Specific Conditions 227 through 235, and 246 through 262 for up to 18 months after the issuance of Air Permit 0573-AOP-R16, or until the new DMW 2 Plant (SN-59) begins operations, whichever is first.

227. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of the boiler. The tons per year emission rate limits are based on the permitted annual natural gas usage of the boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 232 through 235. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
61	Start-up Boiler (240 MMBtu/hr) Operating Scenario # 1	PM_{10}	2.4	10.6
		$PM_{2.5}$	2.0	8.5
		Lead	0.01	0.01

228. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of the boiler. The tons per year emission rate limits are based on the permitted annual natural gas usage of the boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition 232, 233, and 234, and Plantwide Conditions 13 through 42. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
61	Start-up Boiler (240 MMBtu/hr) Operating Scenario # 1	PM	2.4	10.6
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.02	0.08
		Hexane	0.44	1.86
		Mercury	0.01	0.01

229. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of the boiler. The tons per year emission rate limits are based on the permitted annual natural gas usage of the boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 230, and 232 through 235. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
61	Start-up Boiler (240 MMBtu/hr) Operating Scenario # 1	SO_2	0.2	0.8
		VOC	1.0	4.3
		CO	8.9	38.9
		NO_x	4.4	19.0
		CO_2e	28,176.2	123,411.0

230. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 231 through 235. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-61	Start-up Boiler (240 MMBtu/hr)	Opacity	Combustion of natural gas, and good and efficient operating practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.18 lb/hr (3-hr average)
		VOC		0.004 lb/MMBtu (3-hr average) 0.96 lb/hr (3-hr average)
		CO		0.037 lb/MMBtu (3-hr average) 8.88 lb/hr (3-hr average)
		NO_x	Low NOx burners and flue gas recirculation at the boiler Combustion of clean fuel Good Combustion Practices	0.018 lb/MMBtu (3-hr average) 4.32 lb/hr (3-hr average)
		GHG	Good operating practices	CO_2 117 lb/MMBtu CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average)

231. The permittee shall not exceed 0% opacity from SN-61 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-61 is demonstrated by compliance with Specific Condition 232. [Regulation 19, §19.503 and §19.901; and 40 CFR 52, Subpart E]

232. The permittee shall burn only pipeline quality natural gas in the Start-up Boiler (SN-61). [Regulation 19, §19.705 and §19.901; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

233. The permittee shall not combust in excess 2,061.18 million standard cubic feet of natural gas during any consecutive 12-month period at SN-61. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

234. The permittee shall maintain monthly records of the amount of natural gas combusted each month to demonstrate compliance with Specific Condition 233. Records shall be updated by the 15th day of the month for which the records pertain. These records shall

be kept on site, and shall be made available to Department personnel upon request. A twelve month rolling average and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and §19.901 et seq. and 40 CFR Part 52, Subpart E]

235. The permittee shall test SN-61 for PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, CO, and NO_x emissions. This test shall be conducted in accordance with Plantwide Condition 3, and once every 12 months thereafter. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. The permittee shall use EPA Reference Method 5 for PM, EPA Reference Methods 201 or 201A and 202 for PM_{10} and $PM_{2.5}$. The test for PM_{10} and $PM_{2.5}$ shall include filterable and condensable emissions. The permittee shall use EPA Reference Methods 6C, 25A, 10, and 7E for SO_2, VOC, CO, and NO_x, respectively. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. [Regulation 19, §19.702 and §19.901; and 40 CFR Part 52, Subpart E]

Operating Scenario # 2

Specific Conditions

236. The permittee shall comply with Specific Conditions 237 through 262 after the time period specified in Specific Condition 226.

237. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of the boiler. The tons per year emission rate limits are based on the permitted annual natural gas usage of the boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 242, 243, 244, and 245. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
61	Start-up Boiler (240 MMBtu/hr)	PM_{10}	2.4	3.2
		$PM_{2.5}$	2.0	2.6
		Lead	0.01	0.01

238. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of the boiler. The tons per year emission rate limits are based on the permitted annual natural gas usage of the boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition 242, 243, and 244, and Plantwide Conditions 13 through 42. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
61	Start-up Boiler (240 MMBtu/hr)	PM	2.4	3.2
		Arsenic	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.02	0.03
		Hexane	0.44	0.56
		Mercury	0.01	0.01

239. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of the boiler. The tons per year emission rate limits are based on the permitted annual natural gas usage of the boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 240, 242, 243, 244, and 245. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
61	Start-up Boiler (240 MMBtu/hr)	SO_2	0.2	0.3
		VOC	1.0	1.3
		CO	8.9	11.7
		NO_x	4.4	5.7
		CO_2e	28,176.2	37,023.7

240. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 241, 242, 243, 244, and 245. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-61	Start-up Boiler (240 MMBtu/hr)	Opacity	Combustion of natural gas, and good and efficient operating practices	0%
		SO_2		0.00074 lb/MMBtu (3-hr average) 0.18 lb/hr (3-hr average) 0.23 tons per rolling 12 months
		VOC		0.004 lb/MMBtu (3-hr average) 0.96 lb/hr (3-hr average) 1.26 tons per rolling 12 months
		CO		0.037 lb/MMBtu (3-hr average) 8.88 lb/hr (3-hr average) 11.67 tons per rolling 12 months
		NO_X	Low NOx burners and flue gas recirculation at the boiler Combustion of clean fuel Good Combustion Practices	0.018 lb/MMBtu (3-hr average) 4.32 lb/hr (3-hr average) 5.68 tons per rolling 12 months
		GHG	Good operating practices	CO_2 117 lb/MMBtu CH_4 0.0022 lb/MMBtu (3-hr average) N_2O 0.00022 lb/MMBtu (3-hr average) CO_2e 37,023.69 tons per rolling 12 months

241. The permittee shall not exceed 0% opacity from SN-61 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-61 is demonstrated by compliance with Specific Condition 242. [Regulation 19, §19.503 and §19.901; and 40 CFR 52, Subpart E]

242. The permittee shall burn only pipeline quality natural gas in the Start-up Boiler (SN-61). [Regulation 19, §19.705 and §19.901; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

243. The permittee shall not combust in excess 618.35 million standard cubic feet of natural gas during any consecutive 12-month period at SN-61. [Regulation 19, §19.705 and §19.901 et seq., A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR Part 70.6]

244. The permittee shall maintain monthly records of the amount of natural gas combusted each month to demonstrate compliance with Specific Condition 243. Records shall be updated by the 15th day of the month for which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A twelve month rolling average and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and §19.901 et seq. and 40 CFR Part 52, Subpart E]

245. The permittee shall test SN-61 for PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, CO, and NO_x emissions. This test shall be conducted in accordance with Plantwide Condition 3, and once every 12 months thereafter. Once the facility has demonstrated compliance with the permitted emission rates after two consecutive passing tests, then the facility may perform stack testing once every 60 months. The permittee shall use EPA Reference Method 5 for PM, EPA Reference Methods 201 or 201A and 202 for PM_{10} and $PM_{2.5}$. The test for PM_{10} and $PM_{2.5}$ shall include filterable and condensable emissions. The permittee shall use EPA Reference Methods 6C, 25A, 10, and 7E for SO_2, VOC, CO, and NO_x, respectively. If at any time the facility has test results indicating an exceedance of a permitted emission rate, then the facility shall retest for the failing pollutant within 60 days of the failing test, and every 12 months thereafter. When the facility demonstrates that the facility is in compliance with the permitted emission rates after two consecutive passing tests, then the facility may return to performing stack testing once every 60 months. [Regulation 19, §19.702 and §19.901; and 40 CFR Part 52, Subpart E]

246. SN-61 is considered an affected source under 40 CFR Part 60, Subpart Db - *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, and is subject, but not limited to, Specific Conditions 247 through 262. [Regulation 19, §19.304 and 40 CFR Part 60, Subpart Db]

247. Except as provided under paragraphs (k) and (l) of §60.44b, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of §60.44b and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBtu
Natural gas (High heat release rate)	86	0.20

[§60.44b(a)]

248. For purposes of paragraph (i) of §60.44b, the NO_x standards under §60.44b apply at all times including periods of startup, shutdown, or malfunction. [§60.44b(h)]

249. Except as provided under paragraph (j) of §60.44b, compliance with the emission limits under §60.44b is determined on a 30-day rolling average basis. [§60.44b(i)]

250. On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO_2) in excess of the following limits:

a. 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or
b. If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_X emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

c. After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of 40CFR Part 60, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of 40 CFR Part 60.

[§60.44b(l)]

251. The NO_x emission standards under §60.44b apply at all times. [§60.46b(a)]

252. Compliance with the NO_x emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of §60.46b, as applicable. [§60.46b(c)]

253. To determine compliance with the emissions limits for NO_x required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of §60.46b may be used:

a. The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

i. The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)(E_{sg} - E_g) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of 40 CFR Part 60;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of 40 CFR Part 60.

ii. Method 7E of appendix A of this part shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of 40 CFR Part 60 shall be used to determine O_2 concentration.
iii. The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.
iv. Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

b. The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_x and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

[§60.46b(f)]

254. The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

a. Monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted pursuant to §60.49b(c).

[§60.48b(g)(2)]

255. The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

a. The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;
b. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);
c. The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and
d. Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

[§60.49b(a)]

256. The owner or operator of each affected facility subject to the NO_x standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

a. Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_x emission rates (*i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.* , flue gas O_2 level);
b. Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and
c. Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator

during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

[§60.49b(c)]

257. Except as provided in paragraph (d)(2) of §60.49b, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of §60.49b.

a. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.
b. As an alternative to meeting the requirements of paragraph (d)(1) of §60.49b, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

[§60.49b(d)]

258. Except as provided under paragraph (p) of §60.49b, the owner or operator of an affected facility subject to the NO_x standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

a. Calendar date;
b. The average hourly NO_x emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;
c. The 30-day average NO_x emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;
d. Identification of the steam generating unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;
e. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

f. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;
g. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;
h. Identification of the times when the pollutant concentration exceeded full span of the CEMS;
i. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and
j. Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of 40 CFR Part 60.

[§60.49b(g)]

259. The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of §60.49b is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

a. Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).
b. Any affected facility that is subject to the NO_x standard of §60.44b, and that:
    i. Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or
    ii. Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_x emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).
c. For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).
d. For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

[§60.49b(h)]

260. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record. [§60.49b(o)]

261. The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of §60.49b. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of

this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format. [§60.49b(v)]

262. The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. [§60.49b(w)]

Miscellaneous Operations

SN-25
Gasoline Storage Tank

Source Description

This 2,000 gallon aboveground storage tank (SN-25) is used to fuel facility vehicles and equipment.

Specific Conditions

263. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 264 and 265. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
25	Gasoline Storage Tank (2000 Gallon)	VOC	13.4	1.4

264. The permittee shall not use in excess of 40,000 gallons of gasoline per rolling 12-month total. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

265. The permittee shall keep records of the gasoline usage through the gasoline storage tank. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 52, Subpart E]

SN-26
Ammonium Nitrate (90% Solution) Storage Tanks

Source Description

Six above ground storage tanks (SN-26) are used to store 90% ammonium nitrate solution for prilling operations. Four (4) of the tanks are 650,000 gallons, and two (2) of the tanks are 1,200,000 gallons for a total storage of 5,000,000 gallons. Air emissions occur due to steam line heaters degrading the ammonium nitrate solution to ammonia.

Specific Conditions

266. The permittee shall not exceed the emission rates set forth in the following table. The pound per hour emission rate limit is based on maximum capacity and tons per year emission rate limits are based on compliance with Specific Conditions 109, 110, and 111. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
26	Ammonium Nitrate Storage Tanks	NH_3	0.21	0.77

SN-29
Nitric Acid Loading

Source Description

A portion of the nitric acid produced at EDCC is loaded into rail cars or trucks. Loading losses occur as vapors and are displaced to the atmosphere by the liquid being loaded into the rail cars or trucks.

Specific Conditions

267. The permittee shall not exceed the emission rates set forth in the following table. The pound per hour emission rate limit is based on engineering estimates. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 268, 269, and 270. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
29	Nitric Acid Loading	HNO_3	Emissions are routed to SN-10	

268. The permittee shall not load in excess of 27,000 gallons (169 tons) of nitric acid (100% acid equivalent) per hour at SN-29. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

269. The permittee shall not load in excess of 250,000 tons of nitric acid (100% acid equivalent) per rolling 12-month total at SN-29. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

270. The permittee shall keep records of the nitric acid shipped by truck and by rail from the facility. These records shall contain the amount of acid loaded for each hour as specified in Specific Condition 268 was loaded, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

SN-31
Frick Ammonia Compressors

Source Description

Fugitive emissions occur from the handling of ammonia in the Frick Compressor Building. Standard Organic Chemical Manufacturing Industry (SOCMI) emission factors for compressors, pumps, valves, and flanges in ammonia service were used to estimate the fugitive ammonia emissions from the Frick Compressor Building.

Specific Conditions

271. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on maximum capacity. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
31	Frick Ammonia Compressors	NH_3	0.44	1.92

SN-32
Ammonia Storage/Distribution Losses

Source Description

Fugitive emissions occur from the handling and distribution of ammonia. Standard Organic Chemical Manufacturing Industry (SOCMI) emission factors for compressors, pumps, valves, and flanges in ammonia service were used to estimate the fugitive ammonia emissions from the Ammonia Storage/Distribution.

Specific Conditions

272. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on maximum capacity. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
32	Ammonia Storage/Distribution Losses	NH_3	1.59	6.97

SN-33
Nitric Acid Production Fugitives

Source Description

Fugitive emissions from the production, handling, mixing, blending decoloration, and storage of nitric acid are generated due to leaks in flanges, valve packings, etc. resulting in the release of nitrogen oxides and nitric acid mist. EDCC has nitrogen trioxide specifications for weak and strong nitric acid ranging from 0.01% to 0.05%.

Specific Conditions

273. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on facility maximum capacity. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 4, 5, 6, 15, 16, 17, 78, 79, and 80. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
33	Nitric Acid Plants Fugitive Emissions	NO_x	0.1	0.1

274. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on facility maximum capacity. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 4, 5, 6, 15, 16, 17, 78, 79, and 80. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
33	Nitric Acid Plants Fugitive Emissions	HNO_3	0.01	0.02

SN-35
Magnesium Oxide Silo Baghouse

Source Description

The magnesium oxide silo baghouse (SN-35) pneumatically receives magnesium oxide powder from semi-truck transport and/or railcar and controls particulate matter from the unloading and storage operations. The baghouse is situated on top of the silo structure which is approximately 50 feet tall.

Specific Conditions

275. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant as limited by Specific Conditions 109, 110, and 111. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
35	Magnesium Oxide Silo Baghouse	PM_{10}	2.0	0.4
		$PM_{2.5}$	2.0	0.4

276. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant as limited by Specific Conditions 109, 110, and 111. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
35	Magnesium Oxide Silo Baghouse	PM	2.0	0.4

277. The permittee shall not exceed 5% opacity from SN-35 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-35 is demonstrated by compliance with Plantwide Condition 8. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

SN-40
Ammonium Nitrate Solution Loading

Source Description

EDCC ships ammonium nitrate solution to customers via trucks and railcars. The content of the solution ranges from 83% to 90% ammonium nitrate. Ammonia emissions occur as a result of the loading of the trucks and railcars.

Specific Conditions

278. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition 279 and 280. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
40	Ammonium Nitrate Solution Loading	NH_3	0.22	0.63

279. The permittee shall not load more than 65,000,000 gallons gallons (373,750 tons at 11.5 lb/gal on an 85% solution basis) per rolling 12-month total of ammonium nitrate solution into railcars and/or trucks. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

280. The permittee shall keep records of the amount of ammonium nitrate solution loaded into railcars and/or trucks. These records shall contain each month's total and the rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent. These records shall be kept on site, made available to the Department personnel upon request, and submitted in accordance with General Provision 7. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-58
Ammonia Rail and Truck Loading

Source Description

Liquid ammonia is sold as product and shipped by truck and/or railcar (SN-58).

Specific Conditions

281. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 282 and 283. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
58	Ammonia Rail and Truck Loading	NH_3	9.20	13.01

282. The permittee shall not load in excess of 226,300 tons of Ammonia per rolling 12-month total. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

283. The permittee shall keep records of the Ammonia loading. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 52, Subpart E]

SN-62
Haul Road Fugitives

Source Description

Transport trucks and facility vehicles operate on paved and unpaved roads at the facility. Particulate matter emissions occur due to the vehicle traffic (SN-62).

Specific Conditions

284. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be shown by application of dust suppressant as necessary to control dust emissions. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
62	Haul Road Fugitives	PM_{10}	1.5	4.4
		$PM_{2.5}$	0.2	0.5

285. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be shown by application of dust suppressant as necessary to control dust emissions. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
62	Haul Road Fugitives	PM	6.7	20.8

286. Dust suppression activities should be conducted in a manner and at a rate of application that will not cause runoff from the area being applied. Best Management Practices (40 CFR §122.44(k)) should be used around streams and waterbodies to prevent the dust suppression agent from entering Waters of the State. Except for potable water, no agent shall be applied within 100 feet of wetlands, lakes, ponds, springs, streams, or sinkholes. Failure to meet this condition may require the permittee to obtain a National Pollutant Discharge Elimination System (NPDES) permit in accordance with 40 CFR §122.1(b). [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

287. The permittee shall implement a fugitive emission dust control plan to control dust emissions from the roadways. The permittee shall submit for Department approval a fugitive dust control plan for the roadways six months after issuance of Air Permit 0573-AOP-R16. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-64
KT LDAN Curing and Handling Warehouse Fugitives

Source Description

This 10,000 ft^2 warehouse will be used to cure LDAN product and prepare it for shipping. This material handling operation will be conducted inside a closed, air-conditioned building and any particulate emissions will be minimal.

Specific Conditions

288. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 130, 131, and 132. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
64	KT LDAN Curing and Handling Warehouse Fugitives	PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1

289. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 130, 131, and 132. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
64	KT LDAN Curing and Handling Warehouse Fugitives	PM	0.1	0.4

SN-65
Emergency Water Pump

Source Description

An 80 Hp emergency water pump engine is on site in case of emergencies.

Specific Conditions

290. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 294 through 296. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
65	80 Hp Emergency Water Pump	PM_{10}	0.2	0.1
		$PM_{2.5}$	0.2	0.1
		SO_2	0.2	0.1
		VOC	0.2	0.1
		CO	0.6	0.1
		NO_x	2.5	0.2
		CO_2e	91.7	4.6

291. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 294 through 296. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
65	80 Hp Emergency Water Pump	PM	0.2	0.1

292. The permittee shall not exceed 20% opacity from SN-65 as measured by EPA Reference Method 9. Compliance with this Interim Condition shall be demonstrated by compliance with Specific Condition 293. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

293. The permittee shall conduct annual visible emissions observations as a method of compliance verification for the opacity limit assigned for SN-65. Observations shall be conducted by someone trained in EPA Reference Method 9. If during the observations,

visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

a. Take immediate action to identify the cause of the visible emissions,
b. Implement corrective action, and
c. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9 for point sources and in accordance with EPA Method 22 for non-point sources. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.
d. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

e. The time and date of each observation/reading,
f. Any observance of visible emissions appearing to be above permitted limits or any Method 9 reading which indicates exceedance,
g. The cause of any observed exceedance of opacity limits, corrective actions taken, and results of the reassessment, and
h. The name of the person conducting the observation/reading.

294. The permittee shall not operate the emergency diesel air compressor (SN-65) in excess of 100 hours per calendar year. If the permittee operates SN-65 in excess of 100 hours during any calendar year, the permittee shall provide the necessary documentation to demonstrate that the engine still qualifies as an emergency engine as outlined in §60.4211(f). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

295. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Conditions 294. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site and made available to Department personnel upon request. A calendar year total and each individual month's data shall be recorded. [Regulation 19, §19.705 and 40 CFR 52, Subpart E]

296. SN-65 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all applicable provisions of 40 CFR Part 63, Subpart ZZZZ no later than May 3, 2013, which includes, but is not limited to, Specific Conditions 297 through 309. [Regulation 19, §19.304 and 40 CFR Part 63, Subpart ZZZZ]

297. You must be in compliance with the emission limitations, operating limitations, and other requirements in 40 CFR Part 63, Subpart ZZZZ that apply to you at all times. [Regulation 19, §19.304 and 40 CFR Part 63, §63.6605(a)]

298. At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [Regulation 19, §19.304 and 40 CFR Part 63, §63.6605(b)]

299. The permittee shall operate and maintain SN-65, and after-treatment control device (if any), according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(e)]

300. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(f)]

301. If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to 40 CFR Part 63, Subpart ZZZZ apply. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(h)]

302. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to 40 CFR Part 63, Subpart ZZZZ or in items 1 or 4 of Table 2d to 40 CFR Part 63, Subpart ZZZZ, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to 40 CFR Part 63, Subpart ZZZZ. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to 40 CFR Part 63, Subpart ZZZZ. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has

changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(i)]

303. As stated in §63.6602 and §63.6640, the permittee shall comply with the following requirements for existing stationary RICE located at major source of HAP emissions:

For each	The permittee shall meet the following requirement, except during periods of startup	During periods of startup the permittee shall
SN-65[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2c of Subpart ZZZZ, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.
[2] Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of Subpart ZZZZ.
[3] Source can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[Regulation 19, §19.304, and 40 CFR Part 63, §63.6602, §63.6640(a), and Table 2c]

304. As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each	Complying with the following requirement:	The permittee must demonstrate continuous compliance by:
SN-65	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[Regulation 19, §19.304, and 40 CFR Part 63, §63.6640(a), and Table 6]

305. You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to 40 CFR Part 63, Subpart ZZZZ that apply to you. These instances are deviations from the emission and operating limitations in 40 CFR Part 63, Subpart ZZZZ. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6640(b)]

306. If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of §63.6640. In order for the engine to be considered an emergency stationary RICE under 40 CFR Part 63, Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of §63.6640, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of §63.6640, the engine will not be considered an emergency engine under 40 CFR Part 63, Subpart ZZZZ and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of §63.6640 for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of §63.6640counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of §63.6640. Except as provided in paragraphs (f)(4)(i) and (ii) of §63.6640, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[Regulation 19, §19.304 and 40 CFR §63.6640(f)(1), (f)(2), and (f)(4)]

307. If the permittee must comply with the emission and operating limitations, the permittee must keep the records described in paragraphs (a)(1) through (a)(5), and (b)(1) through (b)(3) of 40 CFR Part 63, Subpart ZZZZ. These records include, but are not limited to, the following:

a. A copy of each notification and report that the permittee submitted to comply with 40 CFR Part 63, Subpart ZZZZ, including all documentation supporting any Initial Notification or Notification of Compliance Status that the permittee submitted, according to the requirement in §63.10(b)(2)(xiv).
b. Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.
c. Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).
d. Records of all required maintenance performed on the air pollution control and monitoring equipment.
e. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[Regulation 19, §19.304, and 40 CFR Part 63, §63.6655(a)(1) through (a)(5)]

308. The permittee must keep the records required in Table 6 of 40 CFR Part 63, Subpart ZZZZ to show continuous compliance with each emission or operating limitation that applies to the permittee. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6655(d)]

309. The permittee must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that the permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's own maintenance plan. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6655(e)]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

El Dorado Chemical Company will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19 §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) calendar days after completing the testing. [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19 §19.303 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

7. The permittee shall maintain and employ the Startup, Shutdown, and Malfunction Plan for SN-07, SN-08, SN-09, SN-13, SN-41, SN-49, SN-59, and SN-63. If the Department requests a review of the SSM, the permittee will make the SSM available for review.

The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. The SSMP shall include requirements to record any downtime, malfunction, startup, or shutdown. Any deviations from a permit requirement shall be reported to the Department in accordance with General Provision #8 with the exception that exceedences to which procedures exist in the SSM Plan may be reported as part of the semi-annual reporting. The Department reserves the right to review any such exceedences in accordance with provisions of §19.601. [Regulation 18, §18.801 and §18.1004, Regulation 19 §19.601, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

8. Daily observations of the opacity from SN-05, SN-07 through SN-10, SN-13 thru SN-15, SN-18, SN-19, SN-21, SN-27, SN-28, SN-34, SN-35, SN-41, SN-44, SN-47, SN-49, SN-59, and SN-63 shall be conducted by a person trained, but not necessarily certified, in EPA Reference Method 9. If emissions which appear to be in excess of the permitted level are observed, the permittee shall take immediate action to identify and correct the cause of the visible emissions. After corrective action has been taken, which may include shutting down and restarting the unit, the permittee shall conduct another observation of the opacity from this source. If the opacity observed does not appear to be in excess of the permitted level, then no further action is needed, and the permittee will be considered in compliance with the permitted opacity limit. If visible emissions which appear to be in excess of the permitted level are still observed, a 6-minute visible emissions reading shall be conducted by a person certified in EPA Reference Method 9 to determine if the opacity is less than the permitted level. If the opacity observed is not in excess of the permitted level, then no further action is needed, and the permittee will be considered in compliance with the permitted opacity limit and 19.705 of Regulation #19. If no Method 9 reading is conducted despite emissions appearing to be in excess of the permitted level after corrective action has been taken, the permittee shall be considered out of compliance with the permitted opacity limit and 19.705 of Regulation #19 for that day. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, and made available to Department personnel upon request and shall include:

a. The date and time of the observation;
b. If visible emissions which appeared to be above the permitted limit were detected;
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken; and
d. The name of the person conducting the opacity observations. For observations made on weekends or holidays, the report may be prepared by a member of the environmental compliance staff who may not have actually observed the emissions. This report will be based upon an interview with the person who actually observed the emissions conducted by a member of the environmental

compliance staff who is certified in EPA Reference Method 9. This report must be completed on or before the next business day.

[Regulation 18, §18.1004, Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52 Subpart E]

9. The permittee shall only use pipeline quality natural gas as fuel for sources complying with this condition located at this facility. Pipeline quality natural gas is defined as gas which contains less than 0.25 grains total sulfur per 100 standard cubic feet of natural gas. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 BTU per standard cubic foot. Compliance with this condition may be demonstrated by a valid gas tariff, purchase contract, fuel analysis or other appropriate documentation, or periodic testing. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311 and 40 CFR 70.6]

10. The permittee shall install, operate, and maintain ambient air monitors for Ozone and NO_2. The permittee shall submit a monitoring protocol to the Department within 180 days of the anticipated start up date of the affected sources from the PSD application for permit 0573-AOP-R16. The Department must approve of the monitoring protocol prior to installation of the monitors. The monitors shall be installed and operating within 180 days of the startup of the New Weak Nitric Acid Plant (SN-59) and the Ammonia Plant Primary Reformer (SN-49). [Regulation 19, §19.502 and §19.901; Regulation 26, §26.701; and 40 CFR Part 52 Subpart E]

11. The permittee shall determine the particle size distribution for the particulate matter emissions (PM, PM_{10}, and $PM_{2.5}$) that occur due to loading at SN-27 & SN-28. The permittee shall submit a particle size distribution protocol to the Department within 180 days of the issuance of Air Permit 0573-AOP-R16. The protocol shall contain information pertaining to the date(s) the facility plans on conducting the particle size distribution and the method(s) the facility will employ to determine the particle size distribution. [Regulation 19, §19.502; Regulation 26, §26.701; and 40 CFR Part 52 Subpart E]

12. The permittee shall complete the fence around the property, according to the air dispersion modeling submitted to the Department, within 90 days of start up of the Expansion Project. The following table contains the UTM coordinates provided to the Department. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

UTM East West (X)	UTM North South (Y)
527756.6	3681900
527748.1	3681819
527832.9	3681722
527900.8	3681616

UTM East West (X)	UTM North South (Y)
527926.2	3681561
527917.8	3681378
527896.6	3681272
527799	3681179
527769.3	3681158
527765.1	3680437
527841.4	3680437
527841.4	3679750
528036.5	3679674
528095.9	3679636
528634.4	3679636
528638.6	3679483
529003.3	3679483
529003.3	3679309
529151.7	3679309
529151.7	3679627
530029.5	3679627
530029.5	3680568
531297.4	3680475
531187.1	3680806
530216.1	3680827
530216.1	3681234
529944.7	3681234
529944.7	3681645
529635.1	3681645
529635.1	3682409
529185.6	3682409
529185.6	3682388
529028.7	3682388
529028.7	3682426
528744.6	3682421
528740.4	3681908

NESHAP Subpart DDDDD Requirements

13. SN-48, SN-49, SN-54, and SN-61 are considered affected sources under 40 CFR Part 63, Subpart DDDDD - *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, and is subject, but not limited to, Plantwide Conditions 14 through 42. [Regulation 19, §19.304 and 40 CFR Part 63, Subpart DDDDD]

14. If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later. [§63.7495(a)]

15. If you have an existing boiler or process heater, you must comply with 40 CFR Part 63, Subpart DDDDD no later than January 31, 2016, except as provided in §63.6(i). [§63.7495(b)]

16. You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of 40 CFR Part 63. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in 40 CFR Part 63, Subpart DDDDD. [§63.7495(d)]

17. You must meet the requirements in paragraphs (a)(1) through (3) of §63.7500, except as provided in paragraphs (b), through (e) of §63.7500. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of §63.7500. [§63.7500(a)]

18. As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in §63.7500. [§63.7500(b)]

19. Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to 40 CFR Part 63, Subpart DDDDD, the annual tune-up, or the energy assessment requirements in Table 3 to 40 CFR Part 63, Subpart DDDDD, or the operating limits in Table 4 to 40 CFR Part 63, Subpart DDDDD. [§63.7500(c)]

20. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to 40 CFR Part 63, Subpart DDDDD, or the operating limits in Table 4 to 40 CFR Part 63, Subpart DDDDD. [§63.7500(e)]

21. In response to an action to enforce the standards set forth in §63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at §63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief. [§63.7501]

22. You must be in compliance with the emission limits, work practice standards, and operating limits in 40 CFR Part 63, Subpart DDDDD. These limits apply to you at all

times the affected unit is operating except for the periods noted in §63.7500(f). [§63.7505(a)]

23. For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to 40 CFR Part 63, Subpart DDDDD within the applicable annual, biennial, or 5-year schedule as specified in §63.7540(a) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7540(a). [§63.7510(g)]

24. For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to 40 CFR Part 63, Subpart DDDDD, as specified in paragraphs (a) through (d) of §63.7510, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to 40 CFR Part 63, Subpart DDDDD. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to 40 CFR Part 63, Subpart DDDDD, no later than the compliance date specified in §63.7495. [§63.7510(j)]

25. If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source. [§63.7515(d)]

26. For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to 40 CFR Part 63, Subpart DDDDD, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to 40 CFR Part 63, Subpart DDDDD. You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up. [§63.7515(g)]

27. If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit. [§63.7530(d)]

28. You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to 40 CFR Part 63, Subpart DDDDD and is an accurate depiction of your facility at the time of the assessment. [§63.7530(e)]

29. You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e). [§63.7530(f)]

30. You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to 40 CFR Part 63, Subpart DDDDD, the work practice standards in Table 3 to 40 CFR Part 63, Subpart DDDDD, and the operating limits in Table 4 to 40 CFR Part 63, Subpart DDDDD that applies to you according to the methods specified in Table 8 to 40 CFR Part 63, Subpart DDDDD and paragraphs (a)(1) through (19) of §63.7540.

    a. If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of §63.7540. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.
        i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;
        ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
        iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

vi. Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of §63.7540,

1. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;
2. A description of any corrective actions taken as a part of the tune-up; and
3. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

b. If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of §63.7540 to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of §63.7540 until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

c. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

[§63.7540(a)(10), (a)(12), and (a)(13)]

31. You must submit to the Administrator all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply to you by the dates specified. [§63.7545(a)]

32. As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. [§63.7545(c)]

33. If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8). [§63.7545(e)]

34. If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

    a. The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.
    b. The currently applicable subcategory under 40 CFR Part 63, Subpart DDDDD.
    c. The date upon which the fuel switch or physical change occurred.

    [§63.7545(h)]

35. You must submit each report in Table 9 to 40 CFR Part 63, Subpart DDDDD that applies to you. [§63.7550(a)]

36. You must keep records according to paragraphs (a)(1) of §63.7555, which includes a copy of each notification and report that you submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv). [§63.7555(a)(1)]

37. If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to 40 CFR Part 63, Subpart DDDDD, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under 40 CFR Part 63, other gas 1 fuel, or gaseous fuel subject to another subpart under 40 CFR Part 63 or 40 CFR Part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies. [§63.7555(h)]

38. You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown. [§63.7555(i)]

39. You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown. [§63.7555(j)]

40. Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1). [§63.7560(a)]

41. As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [§63.7560(b)]

42. You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years. [§63.7560(c)]

Title VI Provisions

43. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

44. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)

e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

45. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

46. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

47. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated January 31, 2013.

Description	Category
Molten Sulfur Storage Tank (formerly SN-23)	B-21
Diesel Storage Tank (500 Gallon) (formerly SN-24)	A-3
Diesel Storage Tank (500 Gallon) (formerly SN-36)	A-3
Diesel Storage Tank (2,000 Gallon) (formerly SN-45)	A-3
2 x Ammonia Flares	A-13
Air Liquide Cooling Tower	A-13
Sulfur Unloading/Storage	A-13
Ammonia Offloading	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and Regulation 26 §26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26 §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26 §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

    [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26 §26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26 §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 CFR 70.6(a)(3)(iii)(A) and Regulation 26 §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location;
      ii. The process unit or emission source deviating from the permit limit;
      iii. The permit limit, including the identification of pollutants, from which deviation occurs;
      iv. The date and time the deviation started;
      v. The duration of the deviation;
      vi. The average emissions during the deviation;
      vii. The probable cause of such deviations;
      viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
      ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19 §19.601 and §19.602, Regulation 26 §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26 §26.701(E), and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26 §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26 §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26 §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26 §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26 §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26 §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26 §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26 §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26 §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26 §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26 §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26 §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26 §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and

c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18 §18.314(A), Regulation 19 §19.416(A), Regulation 26 §26.1013(A), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

    a. Such a request does not violate a federal requirement;
    b. Such a request is temporary in nature;
    c. Such a request will not result in a condition of air pollution;
    d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
    e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
    f. The permittee maintains records of the dates and results of such temporary emissions/testing.

    [Regulation 18 §18.314(B), Regulation 19 §19.416(B), Regulation 26 §26.1013(B), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

    a. The request does not violate a federal requirement;
    b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
    c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

    [Regulation 18 §18.314(C), Regulation 19 §19.416(C), Regulation 26 §26.1013(C), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Existing Units Operating Scenario

SECTION I: FACILITY INFORMATION

PERMITTEE:	El Dorado Chemical Company
AFIN:	70-00040
PERMIT NUMBER:	0573-AOP-R16
FACILITY ADDRESS:	4500 North West Avenue El Dorado, AR 71730
MAILING ADDRESS:	P.O. Box 231 El Dorado, AR 71730
COUNTY:	Union County
CONTACT NAME:	Kyle Wimsett
CONTACT POSITION:	Environmental, Health, and Safety Manager
TELEPHONE NUMBER:	870-863-1484
REVIEWING ENGINEER:	Joseph Hurt
UTM North South (Y):	Zone 15: 3680583.92 m
UTM East West (X):	Zone 15: 529356.41 m

SECTION II: INTRODUCTION

Summary of Permit Activity

El Dorado Chemical Company (EDCC) owns and operates a chemical manufacturing facility located at 4500 North West Avenue in El Dorado, Arkansas. EDCC submitted a major prevention of significant deterioration (PSD) modification application to expand the facility. The PSD application changes can be found under Section II of the Expansion Project Operating Scenario. For the Existing Units Operating Scenario, the following changes are occurring with this modification:

1. Removal of the UHDE Direct Strong Nitric Acid Plant (SN-22);
2. Removal of the DSN Plant Cooling Tower (SN-39);
3. Removal of the KT Plant Cooling Tower (SN-43);
4. Addition of the Haul Road Fugitive Emissions (SN-62); and
5. Addition of the diesel fire Emergency Water Pump (SN-65).

The total permitted emission increases include 9.7 tpy of PM, 0.1 tpy of SO_2, 0.1 tpy of VOC, and 0.1 tpy of CO. The total permitted emission decreases include 7.4 tpy of PM_{10}, 143.6 tpy of NO_x, and 55.98 tpy of Nitric Acid.

Process Description

EDCC manufactures nitric acid (various strengths ranging from 48% to 98.5%), sulfuric acid (93.0% and 98.0% strengths), high density grade ammonium nitrate (nitrogen fertilizer for agricultural use) and low density grade ammonium nitrate (for use in industrial applications).

East and West Nitric Acid Plants

The East and West Nitric Acid Plants produce weak nitric acid at concentrations ranging from 52% to 58%. These nitric acid plants employ the DuPont single (high) pressure process designed and built in 1962 by C&I Girdler. Therefore, the East and West Nitric Acid Plants are not subject to NSPS 40 CFR 60, Subpart G – New Source Performance Standard for Nitric Acid Plants since they were constructed prior to August 17, 1971.

Liquid ammonia is received through a pipeline or by truck from intermediate storage and enters a surge tank, where the liquid ammonia level is controlled. The surge tank aids in maintaining a steady flow and controls the ammonia pressure. Purge valves remove oil, water, and inert gases from the ammonia before it exits the bottom of the surge tank through two lines. The ammonia is then delivered through a level control valve to a vaporizer, where the ammonia is vaporized. The ammonia vapor is transferred to the mixer pipe, where it is mixed with preheated air through a series of nozzles. The mixture is maintained at approximately 10% (by volume) ammonia gas. The air and ammonia mixture enters into the top of a converter, where combustion occurs on a platinum catalyst gauze. The temperature of the gas leaving the platinum catalyst is between

1,660 and 1,750° F. At this point, the ammonia is being oxidized to nitrogen oxide(s) and water vapor.

The process gas is then cooled prior to the absorption process. The process gas passes through absorption columns at the East and West Nitric Acid Plants. Product acid (52% to 58% nitric acid) is retried from the bottom of each absorption column and pumped to two 250 ton capacity stainless steel tanks. The tanks share a common vent stack with a water seal at the bottom.

The unabsorbed tail gas, which consists of nitrogen oxides, exits the top of the absorption columns and is passed through Selective Catalytic Reduction (SCR) Units before being vented to the atmosphere through a stack (SN-08 for the West Nitric Acid Plant and SN-09 for the East Nitric Acid Plant). The SCR Units reduce nitrogen oxide emissions by reacting ammonia with nitrogen oxide to form nitrogen gas and water vapor. The stacks are equipped with a nitrogen oxide continuous emission monitoring systems (CEMS), which shall be operated in accordance with the ADEQ CEMS conditions. The CEMS will also be operated consistent with proposed elements of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. The pending global settlement is intended to resolve United States' Clean Air Act (CAA) claims under the Prevention of Significant Deterioration (PSD) program, related to LSB's nitric acid manufacturing facilities. EDCC's East and West Nitric Acid Plants are covered facilities under the pending global settlement.

Fugitive nitrogen oxide emissions (SN-33) from the production, handling, mixing, blending, decoloration, and storage of nitric acid are generated through leaks in flanges, valve packing, etc. Also, nitric acid mist emissions occur due to the loading of nitric acid into rail cars and trucks. Emissions from loading operations (SN-29) are controlled by the Nitric Acid Vent Collection System (SN-10).

DM Weatherly Nitric Acid Plant # 1 (DMW1 Plant)

The DM Weatherly Nitric Acid Plant (SN-13) produces weak nitric acid at a concentration of about 61% - 67% by the oxidization of ammonia in the presence of a catalyst in a similar process to the East and West Nitric Acid Plants. This nitric acid plant was originally installed at the American Cyanamid Company facility at Hannibal, Missouri and was relocated to the El Dorado Chemical in 1990. Therefore, this plant is subject to NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants) since it was constructed or modified after August 17, 1971 and produces weak nitric acid (between 30% and 70 % strength).

Liquid ammonia from the intermediate storage is passed through a set of filters into the ammonia feed vaporizer. Any particulates in the vapor are removed in the ammonia filter. A magnetic filter removes iron residue from the ammonia vapor. The clean ammonia vapor is directed to an ammonia super heater and heated to approximately 330° F. The hot/clean ammonia is conveyed into a Koch ammonia/air mixer, where the process of converting and oxidizing ammonia to nitric acid is initiated. The oxidation of the ammonia is completed as gases pass through a converter elbow. From the converter, the process gas is passed through a series of heat recovery units and then to the absorption column.

The absorption column is divided into three zones. Zone I is the lower part of the column, where the majority of the absorption of nitrogen dioxide to produce the largest amount of nitric acid occurs. Zone II contains a low nitrogen oxide concentration and oxidizes nitric oxide to nitrogen dioxide. Zone III, the upper zone (accounts for approximately 100 feet of the 154 foot column height) of the column, absorbs in condensate low concentrations of nitrogen dioxide, which lowers the nitrogen oxide emissions and allows the plant to produce a consistent 61% - 67% strength nitric acid stream.

The reaction gas stream exiting the top of the absorption tower ("tail/expander gas") is directed through a mist separator and tail gas preheater. The tail gas is routed through a series of heaters/preheaters before being routed to the No. 1 and No. 2 economizers. The economizer's exit stream (consisting of nitrogen, excess oxygen, and unabsorbed nitrogen oxides) is released to the atmosphere through a 50 foot stack (SN-13). A natural gas fired heater (Tail Gas Heater, or SN-48) is used to increase the temperature of the tail gas prior to its introduction to the SCR Unit. The stack is equipped with a nitrogen oxide continuous emission monitoring system (CEMS) as required by 40 CFR Part 60, Subpart G. The CEMS will also be operated consistent with proposed elements of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. The global settlement is intended to resolve United States' Clean Air Act (CAA) claims under the Prevention of Significant Deterioration (PSD) program, related to LSB's nitric acid manufacturing facilities. EDCC's DMW Plant is a covered facility under the pending global settlement.

Fugitive nitrogen oxide emissions (SN-33) from the production, handling, mixing, blending, decoloration, and storage of nitric acid are generated through leaks in flanges, valve packing, etc. Also, nitric acid mist emissions occur due to the loading of nitric acid into rail cars and trucks. Emissions from loading operations (SN-29) are controlled by the Nitric Acid Vent Collection System (SN-10).

Nitric Acid Vent Collection System

In October of 1997, a packed tower hydrogen peroxide scrubber was installed to control NO_x emissions. The top portion of the packed tower treats NO_x emissions from the weak nitric acid storage vents (Tanks 49, 50, and 51). The bottom section of the packed tower treats the NO_x emissions present in the blend acid tanks (Tanks 43, 44, 45, and 46) bleaching air stream. The nitric acid loading system vents (SN-29) are also collected and routed to the packed tower. The overheads from the packed tower are routed through a Venturi Scrubber for additional treatment before being vented to the atmosphere (SN-10). The strong nitric acid storage tanks (Tanks 47, 48, 66, 67, 68, 69, 70, and 71) are routed directly to the Venturi scrubber (i.e., bypass the packed tower). Finally, the nitric acid fumes resulting from the cleaning and pressure checking of rail cars (conducted in the Car Barn) are routed to SN-10.

Sulfuric Acid Plant

The Sulfuric Acid Plant (SN-07), originally constructed in 1949 when Lion Oil Company operated the facility, is a single absorption contact process of the Chemco design. The plant was later modified by Monsanto (Leonard). The plant has been upgraded over the years to include emissions control systems, updated acid cooling technology, and process control equipment. The principal steps in the manufacturing of sulfuric acid are as follows.

The raw material used to initiate the sulfuric acid manufacturing process is elemental (Bright) molten sulfur. The elemental sulfur is delivered to EDCC by rail car or tank truck. The sulfur is unloaded into a heated pit and pumped to a 2,000 ton heated sulfur storage tank (SN-23). The sulfur storage tank is equipped with a control valve, which allows molten sulfur to back flow into the pump pit.

The molten sulfur is pumped from the heated pit to the Sulfuric Acid Plant for the combustion step. While the sulfur is being pumped from the heated pit, atmospheric air is passed through an electric drive blower and sent to a packed tower, where ambient moisture is removed by a recirculating 98% sulfuric acid stream. The predried air is preheated to 420° F in a heat exchanger by waste heat from the first stage of the converter. The air enters the sulfur burner, where sulfur is sprayed into the air and is burned forming sulfur dioxide.

In the conversion step of the process, the sulfur dioxide in the gas stream is combined with some of the remaining oxygen to form sulfur trioxide. A waste heat reboiler located at the exit of the sulfur burner cools the gas exiting the sulfur burner. The sulfur dioxide is converted to sulfur trioxide in the converter, which consists of four layers of catalyst. The gas temperature increases as additional heat is evolved during the conversion process. The sulfur dioxide has the possibility of only partially converting to sulfur trioxide if the gas temperature increases. Therefore, the gases are cooled in three different places in the converter. The gases are cooled in a heat exchanger (which preheats the combustion air) after passing through the first layer of catalyst. Dry air from the 98% drying tower cools the gases as they pass through the second, third, and fourth catalyst layers before exiting the converter.

An economizer (i.e., heat exchanger) cools the gas leaving the converter. The cooling fluid is the incoming water used in the waste heat boiler. The sulfur trioxide made in the converter will not combine directly with water but must be combined indirectly through absorption with 93% sulfuric acid. Under this condition, the sulfur trioxide readily unites with water in the sulfuric acid. This operation is carried out in the absorption tower, where the sulfur trioxide is scrubbed out of the gas stream with 93% sulfuric acid. The gas stream exiting the absorption tower contains inert atmospheric nitrogen, excess oxygen, unreacted sulfur dioxide, and entrained sulfuric acid mist that is routed to the Brinks' Mist Eliminator, which captures sulfuric acid mist prior to the gases being exhausted to the atmosphere through a stack (SN-07).

The 93% sulfuric acid leaves the drying tower, where 98% sulfuric acid is weakened by water vapor removed from atmospheric air. The 93% sulfuric acid is strengthened by sulfur trioxide absorption. There is not enough atmospheric moisture in the air to supply all of the water required for combination with sulfur trioxide to form sulfuric acid. Before it is again pumped to the top of the towers, the absorbing acid is diluted with condensate to the desired strength for efficient sulfur trioxide absorption. This diluted acid is fed at the inlet of the cooler.

Stronger acid from the absorbing tower fortifies the acid from the drying tower, with the makeup being drawn off as product. All dilution condensate is added to the 93% sulfuric acid system. Due to the continuous formation of the greater than 98% sulfuric acid, the volume of acid in the circulation system is proportional to the amount of acid produced. A constant level is maintained by continuously removing 98% sulfuric acid from the pump tank. The removed acid is the production of the plant.

A portion of the sulfuric acid product is loaded into rail cars or trucks. Loading losses (SN-30) (occurring as sulfuric acid vapors) are displaced to the atmosphere by the liquid being loaded into rail cars or trucks.

E2 Ammonium Nitrate Plant

The E2 Ammonium Nitrate Plant has been in operation at El Dorado Chemical Company since the 1950s. It was modified in the early 1980s to allow for the production of either high density ammonium nitrate (HDAN, fertilizer grade) or low density ammonium nitrate (LDAN, industrial grade). However, when the KT Ammonium Nitrate Plant was built in 1989, the production of LDAN at the E2 Plant was discontinued.

HDAN production requires the reaction of weak nitric acid with ammonia to produce an ammonium nitrate solution. The ammonium nitrate is concentrated to a strength greater than 99% for high density prills.

Weak nitric acid from one of the weak nitric acid plants (East and West Nitric Acid Plants and the DMW Plant) and ammonia are reacted in three ammonium nitrate neutralizers (reactors) piped in parallel. After the neutralization reaction, the ammonium nitrate solution (approximately 90% concentration) is fed to a sealed tank, where a pH analyzer adds enough ammonia to complete the reaction with the excess nitric acid. The emissions from the neutralizer overheads, E2 lower concentrator exhaust, and the auxiliary concentrator exhaust are routed to the E2 Plant Chemical Steam Scrubber (SN-41), while the emissions from the E2 prill tower shrouds are routed to the E2 Plant Brinks Scrubber (SN-05).

The ammonium nitrate solution passes through 2 concentration steps (emissions controlled by SN-41). The concentrated ammonium nitrate solution then flows to storage or to the E2 plant prill towers. At each of the prill towers, the concentrated ammonium nitrate solution is broken into droplets by the prill plate and falls countercurrent to cooling air forming prills. The air is pulled through the towers by the E2 ammonium nitrate prill tower fans (SN-06). The prills are further cooled and screened when they exit the prill towers. The air from the cooling process is vented to the Pease-Anthony (Venturi) Scrubber, which is then routed to SN-05 for additional control. The cooled prills are loaded directly onto rail cars or trucks through a common conveyor system (SN-28).

KT Ammonium Nitrate Plant

The Kaltenbach Thuring Ammonium Nitrate Plant manufactures low-density ammonium nitrate for industrial customers. This plant was originally installed at American Cyanamid Corporation in Hannibal, Missouri and was purchased and relocated to El Dorado Chemical Company in 1989.

Weak Nitric Acid from one of the weak nitric acid plants (East and West Nitric Acid Plant and the DM Weatherly Plant) and anhydrous ammonia are heated and fed to the neutralizer (reaction vessel). The highly exothermic reaction of these two chemicals forms ammonium nitrate and steam. The ammonium nitrate solution exits the neutralizer to a pump tank, and the steam condensate is used in the nitric acid plants as an absorption medium. The ammonium nitrate solution is concentrated in the dehydrator to 97% concentration by blowing heated air through the solution. The concentrated ammonium nitrate solution is then pumped to the KT Plant Prilling Tower (SN-14). The overheads dehydrator stream is directed to the Brink's Scrubber (SN-21) prior to being vented to the atmosphere.

The KT Plant Prilling Tower (SN-14) allows droplets of concentrated ammonium nitrate solution to flow for 150 feet countercurrent to ambient air. The droplets crystallize forming solid prills. Air and entrained particulates exit the top of the tower.

The solid prills are removed from the prilling tower and are sent to the predryer and dryer, where heated air is used to remove the remaining moisture. The exhaust air streams from the predryer and dryer are processed through a Ducon type wet scrubber (SN-15) equipped with a mist eliminator.

The prills are cooled (SN-21) and coated with a wax and talc coating to improve flow ability. The cooler air is fed to the Brinks Scrubber for particulate removal. The talc is stored in an enclosed silo, which pneumatically feed in the bulk talc hopper. The silo and hopper are equipped with a baghouse (SN-18) to control particulate matter emissions.

The finished product ammonium nitrate prill stream exits the coater by a discharge elevator into product loading bins. The product is unloaded into either rail cars or trucks (SN-27).

Mixed Acid Plant

The Mixed Acid Plant consists of mix tanks and storage tanks. The mix tanks and the storage tanks utilize a continuously operated scrubber that has 99.5% efficiency for controlling hexavalent sulfur. Periodically, the scrubber is used to bring product into specification, being replaced with fresh scrubber solution during scrubber operation.

EDCC manufactures mixed acid by mixing 15% - 30% oleum (concentrated sulfuric acid) and/or 98% sulfuric acid with 98% nitric acid. The 15% - 30% oleum is purchased from a vendor and delivered to EDCC by railcar or tanker truck, while the 98% sulfuric acid will come from

EDCC's Sulfuric Acid Plant, and the 98% nitric acid will come from EDCC's Nitric Acid Plant. The manufactured mixed acid is stored in the product storage tank or the mixing tank until it is loaded into a railcar or tanker truck. Air emissions from the tanks, the unloading of oleum, and the loading/unloading of the mixed acid into tank cars and/or trucks will be routed to the scrubber (SN-44) prior to being released to the atmosphere.

Natural Gas Fired Boilers

Boilers No. 2 (SN-16A) and No. 4 (SN-16B) are used to supply steam throughout the nitric acid plants, the ammonium nitrate plants, and the sulfuric acid plant. Both boilers are natural gas fired units with identical design heat inputs of 145 million Btu per hour. Emissions from the boilers occur due to the combustion of natural gas. Due to 1990 PSD permitting issues, only one of the steam generating units is allowed to be operated at any one time. However, both steam-generating units will be in operation when the active boiler (for example, Boiler No. 2) is being taken off-line and the other boiler (for example, Boiler No. 4) is being brought on-line. It takes approximately 24 hours for the inactive boiler to warm up and for the unit transition to effectively occur.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective June 18, 2010
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 27, 2013
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective November 18, 2012
EDCC is classified as a PSD major stationary source pursuant to 40 CFR 52.21
The DM Weatherly Nitric Acid Plant (SN-13) is subject to New Source Performance Standards 40 CFR 60 Subpart G, 60.70 through 60.74 (*Standards of Performance for Nitric Acid Plants*)
The Sulfuric Acid Plant (SN-07) is subject to 40 CFR 60 Subpart H (Standards of Performance for Sulfuric Acid Plants).
40 CFR Part 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
40 CFR Part 63, Subpart CCCCCC – *National Emission Standards For Hazardous Air Pollutants For Source Category: Gasoline Dispensing Facilities*
40 CFR Part 64, Compliance Assurance Monitoring

This facility is classified as a major source of greenhouse gas emissions.

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	179.7	344.5
		PM_{10}	174.3	327.4
		$PM_{2.5}$	0.2[c]	0.7[c]
		SO_2	92.5	402.1
		VOC	18.9	5.5
		CO	26.3	59.7
		NO_X	570.1	2,271.0
		CO_2e	69,514.8[c]	292,384.3[c]
		N_2O	216.7[c]	910.0[c]
HAPs		Hexane*	0.60	1.20
Air Contaminants **		HNO_3**	3.61	11.72
		H_2SO_4**	2.91	12.58
		NH_3**	169.20	444.30
		SO_3**	0.05	0.18
SN-02	Emissions routed to SN-41			
SN-03	Emissions routed to SN-41			
SN-04	Emissions routed to SN-41			
SN-05	Ammonium Nitrate E2 Brinks Scrubber	PM PM_{10} NH_3**	14.1 14.1 8.50	281.0[b] 281.0[b] 37.30
SN-06	E2 Ammonium Nitrate Prill Tower Fans	PM PM_{10}	67.0 67.0	281.0[b] 281.0[b]
SN-07	Sulfuric Acid Plant	SO_2 H_2SO_4**	92.0[a] 2.83	401.5 12.35

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-08	West (Weak) Nitric Acid Plant	NO_x NH_3**	200.1 40.00	876.5 62.20
SN-09	East (Weak) Nitric Acid Plant	NO_x NH_3**	200.1 40.00	876.5 62.20
SN-10	Nitric Acid Concentrator Vents	NO_x HNO_3**	19.5 3.40	85.5 10.80
SN-13	DM Weatherly Nitric Acid Plant	NO_x	50.1	210.0
SN-13	DM Weatherly Nitric Acid Plant (controlled by SCR)	NO_x N_2O N_2O as CO_2e NH_3**	16.7 216.7[c] 67,166.7[c] 1.40	42.0 910.0[c] 282,100.0[c] 6.20
SN-14	KT LDAN Prill Tower	PM PM_{10}	44.2 44.2	281.0[b] 281.0[b]
SN-15	KT Plant Dryer/Cooler	PM PM_{10} NH_3**	17.0 17.0 18.00	281.0[b] 281.0[b] 75.60
SN-16A	Boiler No. 2	PM PM_{10} SO_2 VOC CO NO_x Hexane*	1.1 1.1 0.1 0.8 12.0 39.8 0.30	281.0[b] 281.0[b] 0.4 3.5 52.3 174.2 1.20
SN-16B	Boiler No. 4	PM PM_{10} SO_2 VOC CO NO_x Hexane*	1.1 1.1 0.1 0.8 12.0 39.8 0.3	
SN-17	E2 HDAN Plant Cooling Train	Exhaust from Pease Anthony Scrubber is routed to SN-05		
SN-18	KT Plant Clay Baghouse	PM PM_{10}	1.0 1.0	281.0[b] 281.0[b]

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-19	E2 Plant Barometric Tower	PM PM_{10} NH_3**	0.5 0.5 4.10	281.0[b] 281.0[b] 17.70
SN-20	Emissions routed to SN-41			
SN-21	KT Plant Brinks Scrubber	PM PM_{10} NH_3**	3.0 3.0 30.00	281.0[b] 281.0[b] 126.00
SN-25	Gasoline Storage Tank (2000 Gallon)	VOC	16.9	1.4
SN-26	Ammonium Nitrate (90% Solution) Storage	NH_3**	1.60	0.90
SN-27	KT Plant LDAN Loading	PM PM_{10}	0.6 0.6	2.6 2.6
SN-28	E2 Plant HDAN/LDAN Loading	PM PM_{10}	1.1 1.1	4.8 4.8
SN-29	Nitric Acid Loading	HNO_3**	Emissions routed to SN-10	
SN-30	Sulfuric Acid Loading	H_2SO_4**	0.03	0.05
SN-31	Frick Ammonia Compressors	NH_3**	0.50	2.00
SN-32	Ammonia Storage/Distribution	NH_3**	1.30	5.70
SN-33	Nitric Acid Production Fugitives	NO_x HNO_3**	0.1 0.01	0.1 0.02
SN-34	E2 Plant Solution Reactor	PM PM_{10}	0.9 0.9	3.0 3.0
SN-35	Magnesium Oxide Silo Baghouse	PM PM_{10}	2.0 2.0	8.8 8.8
SN-37	Car Barn Scrubber	Source removed in 2008, emissions now routed to SN-10		
SN-38	DM Weatherly Nitric Acid Plant Cooling Tower	PM PM_{10}	1.5 1.5	6.3 6.3
SN-40	Ammonium Nitrate Solution Loading	NH_3**	3.80	4.70

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-41	E2 Plant Chemical Steam Scrubber (30-day rolling average)	PM PM_{10} NH_3**	3.3 3.3 10.00	14.5 14.5 43.80
SN-41	E2 Plant Chemical Steam Scrubber (daily 24-hr average)	PM PM_{10} NH_3**	13.7 13.7 10.00	-- -- --
SN-42	East and West Nitric Acid Plant Cooling Tower	PM PM_{10}	0.3 0.3	1.2 1.2
SN-43	KT Plant Cooling Tower	Source removed in 2013.		
SN-44	Mixed Acid Plant Scrubber	NO_x SO_3** H_2SO_4** HNO_3**	0.4 0.05 0.05 0.20	1.7 0.18 0.18 0.90
SN-46	Sulfuric Acid Plant Cooling Tower	PM PM_{10}	0.2 0.2	0.7 0.7
SN-48	DM Weatherly Nitric Acid Plant Tail Gas Heater (20 MMBtu/hr)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_x CO_2e	0.2 0.2 0.2[c] 0.1 0.2 1.7 1.0 2,348.1[c]	0.7 0.7 0.7[c] 0.1 0.5 7.3 4.3 10,284.3[c]
SN-62	Haul Road Fugitives	PM PM_{10}	6.7 1.5	20.8 4.4
SN-65	Emergency Water Pump	PM PM_{10} SO_2 VOC CO NO_x	0.2 0.2 0.2 0.2 0.6 2.5	0.1 0.1 0.1 0.1 0.1 0.2

a. Based on a 3-hr average.
b. Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.
c. $PM_{2.5}$, N_2O, and CO_2e emissions are only listed for SN-13 and SN-48 due to possible PSD implications with the issuance of Permit 0573-AOP-R15. These pollutants will trigger a PSD review with the next modification submitted by the facility.
* - HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
** - Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

See the permit history under Section III for the Expansion Project Operating Scenario.

SECTION IV: SPECIFIC CONDITIONS

East and West Regular Nitric Acid Plants

SN-08 and SN-09
East and West Nitric Acid Plant

Source Description

The East and West Nitric Acid Plants produce weak nitric acid at concentrations ranging from 52% to 58%. The West Nitric Acid Plant (SN-08) and East Nitric Acid Plant (SN-09) each utilize a C&I Girdler single pressure process to produce weak nitric acid. The East and West Nitric Acid Plants are not subject to NSPS 40 CFR 60, Subpart G – New Source Performance Standard for Nitric Acid Plants, because they were constructed prior to August 17, 1971. The air emissions from these processes are the tail gases from the absorption columns. The absorption columns employ bleaching air to oxidize nitrogen oxide to nitrogen dioxide. The amount of bleaching air used in the process controls the oxygen in the tail gases. The tail gases, which consist of nitrogen oxides, are passed through Selective Catalytic Reduction (SCR) Units before being vented to the atmosphere. The SCR units remove nitrogen oxide emissions by reacting ammonia with nitrogen oxide to form nitrogen gas and water vapor.

The stacks are equipped with a nitrogen oxide continuous emission monitoring systems (CEMS), which shall be operated in accordance with the ADEQ CEMS conditions. The CEMS will also be operated consistent with proposed elements of a draft global settlement resolution pending final agreements between the US EPA and the US Department of Justice (EPA/DOJ) and LSB Industries, which is EDCC's parent company. Each unit has a production capability of 152,387.5 tons of nitric acid per year.

The uncontrolled emissions from SN-08 and SN-09 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because it meets the following criteria: (1) the units are subject to emission limitations for NO_x, (2) the sources are equipped with a control device, and (3) the units have potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for these sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limits at these sources.

Specific Conditions

310. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with the annual emission limits for SN-08 and SN-09 are demonstrated by compliance with Specific Conditions 313, 314, and 315, and satisfactory operation of the SCR Units. [Regulation 19, §19.501 et seq., and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
08	West Nitric Acid Plant	NO_x	200.1	876.5
09	East Nitric Acid Plant	NO_x	200.1	876.5

311. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the lb/hr limit for ammonia for SN-08 and SN-09 will be demonstrated by comparison of the limit to the result of the test conducted pursuant to Specific Condition 316. Compliance with the ton per year limit will be demonstrated by complying with the lb/hr limit. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
08	West Nitric Acid Plant	NH_3	40.00	62.20
09	East Nitric Acid Plant	NH_3	40.00	62.20

312. The permittee shall not exceed 10% opacity from the West Nitric Acid Plant and the East Nitric Acid Plant as measured by EPA Reference Method 9. Compliance with the opacity limit set forth in this Specific Condition will be shown by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

313. The permittee shall not operate either the west nitric acid plant or the east nitric acid plant without its associated SCR unit operating and fully functional except during start up and shut down of each plant. The permittee shall install, calibrate, maintain, and operate a continuous monitoring system for measuring NOx emissions from the West Nitric Acid Plant and the East Nitric Acid Plant. The CEM shall be installed, operated, maintained, and reports submitted per ADEQ's Continuous Emission Monitoring Systems Conditions (listed as Appendix H in the back of this permit). Non-overlapping 3-hour averages, starting at midnight each calendar day, shall be used to demonstrate compliance with the emission rate limits in Specific Condition 310. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

314. The permittee shall not manufacture in excess of 835 tons 100% acid equivalent per day, and 304,775 tons 100% acid equivalent per rolling 12-month total of weak nitric acid through the east and west nitric acid plants. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

315. The permittee shall keep records of the production manufactured in the east and west nitric acid plants. These records shall identify any day during which acid in excess of the quantities specified in Specific Condition 314 was produced, and shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

316. The permittee shall test SN-08 and SN-09 for ammonia emissions. This test shall be conducted within 180 days after the issuance of Air Permit 0573-AOP-R8 and every five years thereafter. Test method CTM-027 or an equivalent method approved by the Department shall be used. Upon a failure of a stack test, the permittee shall stack test annually until two consecutive years are less than the permitted emission rates specified in Specific Condition 311. This unit shall be operated at 90% or more of rated capacity when the tests are completed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. The 5-year testing cycle shall commence after the issuance of Air Permit 0573-AOP-R8 in accordance with Plantwide Condition 3. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-29
Nitric Acid Loading

Source Description

A portion of the nitric acid produced at EDCC is loaded into rail cars or trucks. Loading losses occur as vapors and are displaced to the atmosphere by the liquid being loaded into the rail cars or trucks.

Specific Conditions

317. The permittee shall not exceed the emission rates set forth in the following table. The pound per hour emission rate limit is based on engineering estimates. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 318 and 319. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
29	Nitric Acid Loading	HNO_3	Emissions are routed to SN-10	

318. The permittee shall not load in excess of 200,000 tons of nitric acid (100% acid equivalent) per rolling 12-month total. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

319. The permittee shall keep records of the nitric acid shipped by truck and by rail from the facility. These records shall contain each months total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

SN-33
Production Fugitive Emissions

Source Description

Fugitive emissions from the production, handling, mixing, blending decoloration, and storage of nitric acid are generated due to leaks in flanges, valve packings, etc. resulting in the release of nitrogen oxides and nitric acid mist. EDCC has nitrogen trioxide specifications for weak and strong nitric acid ranging from 0.01% to 0.05%.

Specific Conditions

320. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on facility maximum capacity. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 314, 315, 330, and 331. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
33	Nitric Acid Plants Fugitive Emissions	NO_x	0.1	0.1

321. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on facility maximum capacity. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 314, 315, 330, and 331. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
33	Nitric Acid Plants Fugitive Emissions	HNO_3	0.01	0.02

SN-42
East and West Nitric Acid Plant Cooling Tower

Source Description

EDCC currently operates a cooling tower as part of the East and West Nitric Acid Plant operations.

Specific Conditions

322. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with the annual emission limits for SN-42 is demonstrated by compliance with Specific Condition 325. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
42	East and West Nitric Acid Plant Cooling Tower	PM_{10}	0.3	1.2

323. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the emission limits for SN-42 is demonstrated by compliance with Specific Condition 325. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
42	East and West Nitric Acid Plant Cooling Tower	PM	0.3	1.2

324. The permittee shall not exceed 20% opacity from the West Nitric Acid Plant and the East Nitric Acid Plant Cooling Tower as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-42 is demonstrated by compliance with Specific Condition 325. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

325. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-42 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-42's requirements in Specific Conditions 322, 323, and 324 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

326. The permittee shall cease operations at SN-42 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after ceasing operations at SN-42 and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

DM Weatherly Nitric Acid Plant # 1

SN-13
DMW Nitric Acid Plant # 1

Source Description

The DMW Nitric Acid Plant # 1 (SN-13) produces weak nitric acid (61%-67% strength) by oxidizing ammonia in the presence of a platinum catalyst. The major contributor to air emissions from this process is the absorption column tail gas. In the absorption column, nitrogen dioxide is absorbed into condensate with nitric acid exiting the absorption column. The efficiency of this process determines the amount of nitrogen oxides released to the atmosphere in the tail gas. A SCR will be used to control the NO_x emissions from SN-13. This nitric acid plant was originally installed at the American Cyanamid Company facility at Hannibal, Missouri and was relocated to the El Dorado Chemical in 1990. This plant is subject to NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants), because it was constructed or modified after August 17, 1971 and produces weak nitric acid (between 30% and 70 % strength).

The uncontrolled emissions from SN-13 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for NO_x, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limit at this source.

Specific Conditions 327 through 332 apply to SN-13 before the installation of the SCR.

Specific Conditions

327. Until the Tail Gas Heater (SN-48) and SCR installation is completed and the DM Weatherly Nitric Acid Plant # 1(SN-13) begins operation with the control equipment installed, the permittee shall not exceed the emission rates set forth in the following table for SN-13. The hourly emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by compliance with Specific Conditions 329, 330, and 331. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
13	DM Weatherly Nitric Acid Plant # 1	NO_x	50.1	210.0

328. The permittee shall not exceed 10% opacity from the DM Weatherly Nitric Acid Plant # 1 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-13 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

329. The permittee shall install, calibrate, maintain and operate a continuous monitoring system for measuring nitrogen oxides emissions from the DM Weatherly Nitric Acid Plant # 1 (60.73(a)). The CEM shall be installed, operated, maintained, and reports submitted per ADEQ's Continuous Emission Monitoring Systems Conditions (listed as Appendix H in the back of this permit). The span value shall be 500 ppm of NO_2. The permittee shall establish a conversion factor for converting this reading to pounds NO_2 per ton of 100 percent acid produced (60.73(b)). An hourly value shall be computed by the system for each hour the plant is operating. The permittee shall keep records of daily production rates and hours of operation (60.73(c)). The permittee shall report to the Department as excess emissions any 3-hour period which the average emissions (arithmetic average of any 3 consecutive hours) from the facility exceed 3.0 pounds per ton of 100 per cent acid production (60.73(e)). During periods of startup, shut down, malfunction events, compliance with the limits shall be demonstrated using a CEM to measure the NO_x concentration and flow monitor. The permittee shall report any 3-hour period in which the NO_x emissions (arithmetic average of any 3 consecutive hours) from the facility exceed 50.1 lb/hr (3 lb/ton). [NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants) (listed as Appendix B in the back of this permit)]

330. The permittee shall not manufacture in excess of 140,000 tons 100% acid equivalent per rolling 12 month total of weak nitric acid through the DM Weatherly Nitric Acid Plant # 1. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

331. The permittee shall keep records of the production manufactured in the DM Weatherly Nitric Acid Plant # 1. These records shall contain each months total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

332. The DM Weatherly Nitric Acid Plant # 1 (SN-13) must continuously have nitrogen oxide emissions that do not exceed 3.0 pounds per ton of 100 percent acid production. Compliance with this condition is demonstrated by Specific Condition 329. [NSPS 40 CFR 60 Subpart G]

333. The permittee shall not exceed the N_2O limit of 13.0 lb/ton at the DM Weatherly Nitric Acid Plant # 1 (SN-13). Compliance with this condition is demonstrated by Specific

Condition 329. [Regulation 19, §19.702 and §19.705; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; 40 CFR Part 52, Subpart E ; and 40 CFR 70.6]

Specific Conditions 330, 331, 333, and 334 through 337 apply to SN-13 after the installation of the SCR.

334. After the Tail Gas Heater (SN-48) and SCR installation is completed and the DM Weatherly Nitric Acid Plant # 1 (SN-13) begins operation with the control equipment installed, the permittee shall not exceed the emission limits set forth in the following table for source SN-13. The hourly emission rates are based on maximum capacity. Compliance with this condition will be verified by compliance with Specific Conditions 330, 331, 336, and 337. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
13	DM Weatherly Nitric Acid Plant # 1 (controlled by SCR)	NO_x	16.7	42.0
		N_2O	216.7	910.0
		N_2O as CO_2e	67,166.7	282,100.0

335. After the Tail Gas Heater (SN-48) and SCR installation is completed and the DM Weatherly Nitric Acid Plant # 1 (SN-13) begins operation with the control equipment installed, the permittee shall not exceed the emission limits set forth in the following table for source SN-13. The emission rates are based on maximum capacity and vendor specification. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
13	DM Weatherly Nitric Acid Plant # 1 (controlled by SCR)	NH_3	1.4	6.2

336. The DM Weatherly Nitric Acid Plant # 1 (SN-13) must continuously have NO_x emissions that do not exceed 1.0 lb/ton of 100% nitric acid production on a 3-hr rolling average basis, excluding startup, shutdown, and malfunction (SSM) related emissions and 0.6 lb/ton of 100% nitric acid production on a 365-day rolling average basis, including SSM related emissions. The permittee shall establish a conversion factor for converting this reading to pounds NO_2 per ton of 100 percent acid produced (60.73(b)), and in accordance with the CEMS Plan (listed as Appendix J in the back of this permit). An hourly value shall be computed by the system for each hour the plant is operating. The permittee shall keep records of daily production rates and hours of operation (60.73(c)). The permittee shall report to the Department as excess emissions any 3-hour period in which the average emissions (arithmetic average of any 3 consecutive hours) from the facility exceed 3.0 lb/ton of 100% nitric acid production (60.73(e)). During periods of

startup, shut down, malfunction events, compliance with the limits shall be demonstrated using a CEMS to measure the NO_x concentration and flow monitor. The permittee shall report any 3-hour period in which the NO_x emissions (arithmetic average of any 3 consecutive hours) from the facility exceed 50.1 lb/hr. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; and NSPS 40 CFR 60 Subpart G (New Source Performance Standard for Nitric Acid Plants) (listed as Appendix B in the back of this permit)]

337. The permittee shall install, calibrate, maintain, and operate a dual range CEMS and stack gas flow meter to monitor NO_x emissions from the DM Weatherly Nitric Acid Plant # 1 (SN-13) in accordance with the CEMS Plan (listed as Appendix J in the back of this permit). The permittee shall install, calibrate, maintain, and operate the dual range monitor and stack gas flow meter with the following operational requirements, which are included in the CEMS Plan:

Analyzer	Parameter	Location	Span Value
NO_x Stack Analyzers	NO_x, ppm by volume, dry basis[1]	Stack	Normal: 0 – 500 ppm NO_x, or as appropriate to accurately measure the normal concentration range. SSM: 0 to 125% of the maximum estimated NO_x emission concentration
Stack Flow meter	Volumetric Flow rate, SCFH[2]	Stack	0 to 125% of the maximum expected volumetric flow rate

[1]For the purposes of calculations under the CEMS Plan in Appendix J, as-is NO_x concentration measurements at the DM Weatherly Nitric Acid Plant # 1(e.g., those utilizing FTIR, NDIR, or other types of stack gas analyzers capable of making wet measurements) will be assumed to be dry. However, the permittee may adjust for any moisture contained in the stack gas if the nitric acid plant is equipped with a continuous moisture analyzer or equipment which removes the moisture prior to the stack gas analyzer.
[2]For the purposes of the calculations under the CEMS Plan, as-is volumetric flow rate measurements will be assumed to be dry. However, the permittee may adjust for any moisture contained in the stack gas if the nitric acid plant is equipped with a continuous moisture analyzer.

[A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-38
DMW Nitric Acid Plant #1 Cooling Tower

Source Description

EDCC operates a cooling tower as part of the DMW Nitric Acid Plant.

Specific Conditions

338. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by compliance with Specific Condition 341. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
38	DM Weatherly Nitric Acid Plant # 1 Cooling Tower	PM_{10}	1.5	6.3

339. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 341. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
38	DM Weatherly Nitric Acid Plant # 1 Cooling Tower	PM	1.5	6.3

340. The permittee shall not exceed 20% opacity from the DM Weatherly Nitric Acid Plant # 1 Cooling Tower as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-38 is demonstrated by compliance with Specific Condition 341. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

341. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-38 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-38's requirements in Specific Conditions 338, 339, and 340 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

342. The permittee shall reduce the emissions at SN-38 to a level no greater than the levels specified in Specific Conditions 23 and 24 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at

SN-38 to the levels specified in Specific Conditions 23 and 24, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-48
DMW Nitric Acid Plant # 1 Tail Gas Heater

Source Description

This 20 MMBtu/hr natural gas fired heater is used to crease the temperature of the tail gas prior to its introduction to the SCR Unit.

Specific Conditions

343. The permittee shall not exceed the emission rates set forth in the following table. The emission rate limit is based on maximum capacity of the unit. The permittee shall demonstrate compliance with this condition by Specific Condition 345. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
48	DM Weatherly Nitric Acid Plant # 1 Tail Gas Heater (20 MMBtu/hr)	PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.2	0.5
		CO	1.7	7.3
		NO_x	1.0	4.3
		CO_2e	2,348.1	10,284.3

344. The permittee shall not exceed the emission rates set forth in the following table. The emission rate limit is based on maximum capacity of the unit. The permittee shall demonstrate compliance with this condition by Specific Condition 345. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
48	DM Weatherly Nitric Acid Plant # 1 Tail Gas Heater (20 MMBtu/hr)	PM	0.2	0.7

345. The permittee shall burn only pipeline quality natural gas in SN-42. [Regulation 19, §19.705, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

346. The permittee shall not exceed 5% opacity from the Tail Gas Heater (SN-48) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-48 shall be demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Nitric Acid Vent Collection System

SN-10
Nitric Acid Vent Collection System

Source Description

In October of 1997, a packed tower hydrogen peroxide scrubber was installed to control nitrogen oxide emissions. The top portion of the packed tower treats nitrogen oxide emissions from the weak nitric acid storage vents (Tanks 49, 50, and 51). The bottom section of the packed tower treats the nitrogen oxide emissions present in the blend acid tanks (Tanks 43, 44, 45, and 46) bleaching air stream. The nitric acid loading system vents (SN-29) are also collected and routed to the packed tower. The overheads from the packed tower are routed through a Venturi Scrubber for additional treatment before being vented to the atmosphere through a stack designated as SN-10. The strong nitric acid storage tank vents (Tanks 47, 48, 66, 67, 68, 69, 70 and 71) are routed directly to the Venturi Scrubber (i.e. bypass the packed tower). Overall nitrogen oxide and visible emissions are reduced due to these pollution control devices.

With the issuance of Air Permit 0573-AOP-R8, the Car Barn Scrubber (previously permitted as SN-37) was removed as a source. The nitric acid fumes resulting from the cleaning and pressure checking of rail cars (conducted in the Car Barn) are now routed to SN-10 for control.

The uncontrolled emissions from SN-10 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for NO_x, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of NO_x that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the NO_x emission limit at this source.

Specific Conditions

347. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by proper operation of the Venturi and Packed Tower Scrubber and compliance with Specific Condition 352. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
10	Nitric Acid Vent Collection System	NO_x	19.5	85.5

348. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rates are based on maximum capacity. Compliance with this Specific Condition will be verified by proper operation of the Venturi and Packed Tower Scrubber and compliance with Specific Condition 352. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
10	Nitric Acid Vent Collection System	Nitric Acid	3.40	10.80

349. The permittee shall not exceed 20% opacity from the Nitric Acid vent collection system (SN-10) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-10 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

350. The permittee shall have a third party stack test once every five years the nitrogen oxides emissions from the nitric acid vent collection system using EPA Method 7E and the nitrogen oxides emissions shall be less than the hourly limit specified in Specific Condition 347. Upon failure of a stack test, the permittee shall stack test annually until two consecutive years are below the limits specified in Specific Condition 347. The facility will conduct rail car/truck loading and/or acid blending operations at normal operational rates when the stack test is performed. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

351. The permittee shall have a third party stack test once every five years the nitric acid emissions from the nitric acid vent collection system using an approved method and the nitric acid emissions shall be less than the hourly limit specified in Specific Condition 348. Upon failure of a stack test, the permittee shall stack test annually until two consecutive years are below the limit specified in Specific Condition 348. The equipment which the nitric acid vent collection system serves as a pollution control device shall be operating at normal capacity when the testing is performed. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

352. The permittee shall not operate the nitric acid vent collection system without a functional hydrogen peroxide scrubber and a Venturi and Packed Tower Scrubber. The permittee shall sample, test and record daily the hydrogen peroxide concentration of the chemical condensate circulated at the scrubber outlet. These records shall be updated by the 15th of the month following which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

Sulfuric Acid Plant

SN-07
Sulfuric Acid Plant

Source Description

The Sulfuric Acid Plant (SN-07), originally constructed in 1949 when Lion Oil Company operated the facility, is a single absorption contact process of the Chemco design. The plant was later modified by Monsanto (Leonard). The plant has been upgraded over the years to include emissions control systems, updated acid cooling technology, and process control equipment.

The Sulfuric Acid Plant (SN-07) manufactures sulfuric acid at 93% - 99% strength through the combustion of sulfur to form sulfur dioxide, the use of oxygen to convert the newly formed sulfur dioxide to sulfur trioxide, and then finally the double absorption of sulfur trioxide with water to form sulfuric acid. The Sulfuric Acid Plant is subject to 40 CFR 60 Subpart H (Standard of Performance for Sulfuric Acid Plants), which limits sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions to 4.0 pounds per ton of 100% acid production and 0.15 pounds per ton of 100% acid production, respectively.

The uncontrolled emissions from SN-07 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for SO_2, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of SO_2 that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the SO_2 emission limit at this source.

Specific Conditions

353. The permittee shall not exceed the emission rates set forth in the following table. Compliance of SO_2 with this Specific Condition is demonstrated by compliance with Specific Conditions 356, 357, 358, and 363. Compliance of SO_2 is also demonstrated by the CEM required in Specific Condition 357c. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
07	Sulfuric Acid Plant	SO_2	92.0[a]	401.5
		SO_2	4.0 lb/ton, expressed as 100 percent H_2SO_4, and based on a 3-hr average.	

a. Based on a 3-hr average.

354. The permittee shall not exceed the emission rates set forth in the following table. Compliance of sulfuric acid mists with this Specific Condition is demonstrated by compliance with Specific Conditions 356 and 357. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
07	Sulfuric Acid Plant	H_2SO_4	2.83	12.35

355. The permittee shall not exceed 10% opacity from the Sulfuric Acid Plant (SN-07) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-07 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

356. The permittee shall not manufacture in excess of 200,750 tons of 100% sulfuric acid per rolling 12-month total through the sulfuric acid plant. These records shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; and 40 CFR 70.6]

357. Sulfuric Acid Plant (SN-07) is subject to and shall comply with applicable provisions of 40 CFR Part 60, Subpart H – *Standards of Performance for Sulfuric Acid Plants*. Applicable provisions of Subpart H include, but are not limited to, the following: [Regulation 19, §19.304 and 40 CFR §60.80]

a. The permittee shall not cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4. [Regulation 19, §19.304 and 40 CFR §60.82]
b. The permittee shall not cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H_2SO_4.
(2) Exhibit 10 percent opacity, or greater.
[Regulation 19, §19.304 and 40 CFR §60.83]
c. A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under Performance Specification 2 and for calibration checks under §60.13(d), shall be sulfur dioxide (SO_2). Method 6C shall be used for conducting monitoring system performance evaluations under §60.13(c). The span value shall be set at 1000 ppm of sulfur dioxide. [Regulation 19, §19.304 and 40 CFR §60.84(a)]

d. The permittee shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999–AP–13) and calculating the appropriate conversion factor for each eight-hour period as follows:
$CF=k[(1.000-0.015r)/(r-s)]$
where:
CF=conversion factor (kg/metric ton per ppm, lb/ton per ppm).
k=constant derived from material balance. For determining CF in metric units, k=0.0653. For determining CF in English units, k=0.1306.
r=percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Department's approval.
s=percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under §60.84(a). [Regulation 19, §19.304 and 40 CFR §60.84(b)]

e. The owner or operator shall record all conversion factors and values under §60.84(b) from which they were computed (i.e., CF, r, and s). [Regulation 19, §19.304 and 40 CFR §60.84(c)]

f. Alternatively, a source that processes elemental sulfur or an ore that contains elemental sulfur and uses air to supply oxygen may use the following continuous emission monitoring approach and calculation procedures in determining SO_2 emission rates in terms of the standard. This procedure is not required, but is an alternative that would alleviate problems encountered in the measurement of gas velocities or production rate. Continuous emission monitoring systems for measuring SO_2, O_2, and CO_2 (if required) shall be installed, calibrated, maintained, and operated by the owner or operator and subjected to the certification procedures in Performance Specifications 2 and 3. The calibration procedure and span value for the SO_2 monitor shall be as specified in §60.84(b). The span value for CO_2 (if required) shall be 10 percent and for O_2 shall be 20.9 percent (air). A conversion factor based on process rate data is not necessary. Calculate the SO_2 emission rate as follows:
$Es=(CsS)/[0.265-(0.126\ \%O_2)-(A\ \%CO_2)]$
where:
Es=emission rate of SO_2, kg/metric ton (lb/ton) of 100 percent of H_2SO_4 produced.
Cs=concentration of SO_2, kg/dscm (lb/dscf).
S=acid production rate factor, 368 dscm/metric ton (11,800 dscf/ton) of 100 percent H_2SO_4 produced.
$\%O_2$=oxygen concentration, percent dry basis.
A=auxiliary fuel factor,
=0.00 for no fuel.
=0.0226 for methane.

=0.0217 for natural gas.
=0.0196 for propane.
=0.0172 for No 2 oil.
=0.0161 for No 6 oil.
=0.0148 for coal.
=0.0126 for coke.
$\%CO_2$= carbon dioxide concentration, percent dry basis.
[Regulation 19, §19.304 and 40 CFR §60.84(d)]

g. For the purpose of reports under §60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under §60.82. [Regulation 19, §19.304 and 40 CFR §60.84(e)]
h. The permittee shall comply with the test methods and procedures in 40 CFR §60.85. [Regulation 19, §19.304 and 40 CFR §60.85]

358. The permittee shall not exceed the SO_2 limit defined in 357a during any three-hour period. Compliance with this condition shall be demonstrated by the CEM required in Specific Condition 357c. These records shall be kept on site, and shall be made available to Department personnel upon request. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; 40 CFR 60.82, 60.84(a), and 60.84(e); and 40 CFR 70.6]

A reasonable possibility, as defined under paragraph (r)(6) of 40 CFR §52.21, exists for SO_2 due to the maintenance, repair, and replacement (MRR) activities requested in the application for Permit 0573-AOP-R14.

359. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the SO_2 emission limits is demonstrated by compliance with Specific Conditions 356, 357, 358, and 363. Compliance with the SO_2 emission limits is also demonstrated by the CEM required in Specific Condition 357c. [Regulation 19, §19.501 and §19.901; and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
07	Sulfuric Acid Plant	SO_2	92.0[a]	386.8
		SO_2	4.0 lb/ton, expressed as 100 percent H_2SO_4, and based on a 3-hr average.	

a. Based on a 3-hr average.

360. The permittee shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the maintenance, repair, and replacement (MRR) activities requested in the application for Permit 0573-AOP-R14 and that is emitted by any emissions unit identified in 40 CFR Part 52.21(r)(6)(i)(b); and calculate and maintain a

record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change. The permittee shall demonstrate compliance with this condition by complying with Specific Conditions 95 and 96. [Regulation 19, §19.705 and §19.901; 40 CFR Part 52.21(r)(6)(iii); A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311; and 40 CFR Part 70.6]

361. The permittee shall submit a report to the Administrator if the annual emissions, in tons per year, from the maintenance, repair, and replacement (MRR) activities requested in the application for Permit 0573-AOP-R14, exceed the baseline actual emissions (as documented and maintained pursuant to 40 CFR Part 52.21(r)(6)(i)(c)), by a significant amount (as defined in paragraph 40 CFR Part 52.21(b)(23)) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to 40 CFR Part 52.21(r)(6)(i)(c). Such report shall be submitted to the Administrator within 60 days after the end of such year. The report shall contain the following:

d. The name, address and telephone number of the major stationary source;
e. The annual emissions as calculated pursuant to 40 CFR Part 52.21(r)(6)(iii); and
f. Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

[Regulation 19, §19.705 and §19.901; 40 CFR Part 52.21(r)(6)(v); A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311; and 40 CFR Part 70.6]

362. The permittee shall maintain annual emissions, in tons per year on a calendar basis, of the actual SO_2 emissions from SN-07. The permittee shall use CEMS data when available. When CEMS data is not available, the permittee shall document how the actual emissions were determined, subject to review and approval by the Department. [Regulation 19, §19.705 and §19.901; A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311; and 40 CFR Part 70.6]

363. The permittee shall not manufacture in excess of 550 tons of 100% sulfuric acid per day through the sulfuric acid plant. These records shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004; Regulation 19, §19.705; A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311; 40 CFR Part 52, Subpart E; and 40 CFR Part 70.6]

SN-30
Sulfuric Acid Loading

Source Description

The sulfuric acid produced at EDCC is loaded into rail cars or trucks. Loading losses occurring as vapors are displaced to the atmosphere by the liquid being loaded into the rail cars or trucks.

Specific Conditions

364. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on engineering estimates and production. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition 365. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
30	Sulfuric Acid Loading	H_2SO_4	0.03	0.05

365. The permittee shall not load in excess of 200,750 tons of sulfuric acid (100% acid equivalent) per rolling 12-month total. The permittee shall keep records of the sulfuric acid shipped by truck and by rail from the facility. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

SN-46
Sulfuric Acid Plant Cooling Tower

Source Description

The Sulfuric Acid Plant cooling tower uses a combination of river water and cooling system condensation water to cool the heat generated by the sulfuric acid production process.

Specific Conditions

366. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 369. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
46	Sulfuric Acid Plant Cooling Tower	PM_{10}	0.2	0.7

367. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition 369. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
46	Sulfuric Acid Plant Cooling Tower	PM	0.2	0.7

368. The permittee shall not exceed 20% opacity from the Sulfuric Acid Plant Cooling Tower (SN-46) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-46 is demonstrated by compliance with Specific Condition 369. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

369. The permittee shall test and record the total dissolved solids of the cooling water on a weekly basis when SN-46 is operating. Results less than 1,560 ppm total dissolved solids will demonstrate compliance with SN-46's requirements in Specific Conditions 366, 367, and 368 of this permit. The results shall be kept on site and made available to Department personnel upon request. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

370. The permittee shall reduce the emissions at SN-46 to a level no greater than the levels specified in Specific Conditions 100 and 101 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-46 to the levels specified in Specific Conditions 100 and 101, and shall contain the

date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

E2 Ammonium Nitrate Plant

SN-05, SN-17, and SN-41
Scrubbers

Source Description

The Ammonium Nitrate E2 Plant Brinks Scrubber (SN-05) controls emissions from the air stream from the shroud of the E2 Ammonium Nitrate Prill Tower Fans (SN-06), the intermediate ammonium nitrate storage tanks, and the E2 Plant Chemical Condensate Tank. The E2 Plant Brinks Scrubber (SN-05) is actually two scrubbers, one for each prill tower. EDCC has the ability to shut down one scrubber and the associated prill tower. When one scrubber is shut down, EDCC will not operate the associated prill tower while the scrubber is not operating.

The prills are cooled and screened when they exit the prill tower. The air from the cooling process is vented to the Pease-Anthony (Venturi) Scrubber (SN-17). With the issuance of permit 0573-AOP-R7, emissions from the Pease Anthony Scrubber (SN-17) on the E2 HDAN Plant Cooling Train were routed to SN-05 for additional control.

The E2 Plant Chemical Steam Scrubber (SN-41) controls particulate matter and ammonia emissions from the three E2 Plant Neutralizers (formerly SN-02 and SN-03, and a third neutralizer added in 2002), the Ammonium Nitrate Low Concentrator (formerly SN-04), and the E2 Auxiliary Ammonium Nitrate Concentrator (formerly SN-20).

The uncontrolled emissions from SN-05 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for PM_{10}, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limit at this source.

Specific Conditions

371. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-05 is demonstrated by compliance with Specific Conditions 376, 377, 378, and 379, and the reporting required in Plantwide Condition 7. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05	Ammonium Nitrate E2 Brinks Scrubber	PM_{10}	14.1	*
17	E2 HDAN Plant Cooling Train	Exhaust from Pease Anthony Scrubber is routed to SN-05		

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

372. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-05 is demonstrated by compliance with Specific Conditions 375, 377, 378, and 379, and the reporting required in Plantwide Condition 7. Compliance with the emission limits for SN-41 is demonstrated by compliance with Specific Conditions 377, 378, and 385. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
05	Ammonium Nitrate E2 Brinks Scrubber	NH_3 PM	8.50 14.1	37.30 *
17	E2 HDAN Plant Cooling Train	Exhaust from Pease Anthony Scrubber is routed to SN-05		
41	E2 Plant Chemical Steam Scrubber	NH_3	10.00	43.80

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

373. The permittee shall reduce the emissions at SN-05 to a level no greater than the levels specified in Specific Conditions 104 and 105 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-46 to the levels specified in Specific Conditions 104 and 105, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

374. The permittee shall not exceed 20% opacity from SN-05 and 15% opacity from SN-41 as measured by EPA Reference Method 9. Compliance with the opacity limits set forth in this Specific Condition will be shown by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

375. The permittee shall have a third party test once every five years the NH_3 emissions from SN-17's exhaust prior to the inlet of SN-05 using an approved method. The NH_3 emissions from SN-17 shall be less than 5.0 lb/hr. Upon failure of a test, the permittee shall test annually until two consecutive years are less than 5.0 lb/hr. The units shall be operated at least at 90% of rated capacity when the stack test is completed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-17, 90% rated capacity is defined as:

a. The 90% of the rated capacity of the prill towers will be on an ammonium nitrate production basis.
b. The product exit temperature at the prill towers at the time of test must be less than 275°F.

[Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

376. The permittee shall have a third party stack test the PM_{10} emissions from SN-05 once every five years. Analysis for SN-05 shall be conducted using a method approved in advance by the Department. If the analysis predicts PM_{10} emissions may exceed 13.0 lb/hr, then an audit shall be conducted by an independent third party to evaluate the operating condition of SN-05 and shall recommend any maintenance and/or repairs needed. A copy of the audit report shall be forwarded directly to the Department by the auditor within fifteen (15) days of the completion of the audit. Any necessary maintenance and/or repairs shall be performed by the permittee as expeditiously as possible. The permittee shall repeat the emissions analysis within thirty (30) days after completion of any maintenance and/or repairs. The permittee shall submit the compliance analysis results to the Department with thirty (30) days after completing the analysis. The unit shall be operated at 90% or more of rated capacity when the analysis is conducted. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-05, 90% of rated capacity is defined as:

a. The 90% of the rated capacity of the prill towers will be on an ammonium nitrate production basis.
b. The product exit temperature at the prill towers at the time of test must be less than 275°F.

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

377. The permittee shall not manufacture in excess of 473,040 tons of ammonium nitrate prill through the E2 Ammonium Nitrate Plant during any consecutive 12-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

378. The permittee shall keep records of the ammonium nitrate prill production in the E2 Ammonium Nitrate Plant. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

379. The E2 plant brinks scrubber (SN-05), the E2 Plant HDAN Cooling Train Pease/Anthony Scrubber (SN-17), and the E2 Plant Chemical Steam Scrubber (SN-41) shall be kept in good working condition at all times. SN-05 and SN-17 shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-05 and SN-17 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parametric exceedance, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be made available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision #8 if applicable.

SN	Description	Parameter	Units	Operation Limits
05	E2 Plant Brinks Scrubber	Scrubber Liquid Flow Rate for Each Scrubber	gal/min	225 (minimum)
		Gas Pressure Drop Across Unit for Each Scrubber	in. H_2O	2.5 (minimum)
		pH	-	0.5 - 6.0

SN	Description	Parameter	Units	Operation Limits
17	E2 Plant HDAN Cooling Train Pease/Anthony Scrubber	Scrubber Liquor pH	-	0.5 - 6.0
		Scrubber Liquid Flow Rate (dual scrubbers)	gal/min	120 (minimum per scrubber)
		Amperage	amps	100 (minimum)

[Regulation 18, §18.1004 and A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311]

380. The permittee shall operate, maintain, and submit reports for the continuous monitoring device for SN-41, as required by Specific Condition 385, in accordance with all applicable requirements of ADEQ CEMS Conditions, located in Appendix H of this permit. The applicable requirements of ADEQ CEMS Conditions include, but are not limited to, the following:

a. The stack gas sampling system at SN-41 shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.
b. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.
c. The permittee shall maintain records of the occurrence and duration of startup/shutdown, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of SN-41 which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.
d. The permittee shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.
e. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.
f. The permittee must maintain on site a file of the continuous monitored data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.
g. The permittee shall develop and implement a Quality Assurance/Quality Control (QA/QC) plan within 90 days of permit issuance, and shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability. The permittee must keep a copy of the QA/QC Plan at the source's location and retain all previous versions of the QA/QC Plan for five years.
h. The submitted QA/QC plan shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

i. A back-up monitor may be placed on SN-41 to minimize monitor downtime. This back-up sampling and monitoring system is subject to the same QA/QC procedure and practices as the primary sampling and monitoring system. When the primary sampling and monitoring system goes down, the back-up sampling and monitoring system may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up sampling and monitoring system is placed in service, these records shall include at a minimum the reason the primary sampling and monitoring system is out of service, the date and time the primary sampling and monitoring system was out of service and the date and time the primary sampling and monitoring system was placed back in service.

[Regulation 19, §19.705 and §19.304; 40 CFR Part 52, Subpart E; and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

381. The permittee shall calculate PM_{10} emissions for Plantwide Condition 7 from the E2 Plant Brinks Scrubber (SN-05), and the E2 Prill Tower (SN-06) using a total emission factor of 0.967 lb of PM_{10} per ton of ammonium nitrate produced. These records shall be updated by the 15^{th} of the month following the month which the records represent. These records shall be kept on site and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

382. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the emission limits for SN-41 is demonstrated by compliance with Specific Conditions, 380, 383, 384, and 385. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
41	E2 Plant Chemical Steam Scrubber	PM PM_{10} $PM_{2.5}$	13.7 (daily 24-hr average)	14.5
		PM PM_{10} $PM_{2.5}$	3.3 (30-day rolling average)	

383. The 30-day rolling average PM_{10} emissions from SN-41 shall not exceed 0.054 pound per ton of ammonium nitrate produced at the neutralizers. Compliance is demonstrated by compliance with the PM_{10} testing requirement of Specific Condition 385. [Regulation 19, §19.901 and 40 CFR Part 52 Subpart E]

384. The daily 24-hour average PM_{10} emissions from SN-41 shall not exceed 0.223 pound per ton of ammonium nitrate produced at the neutralizers. Compliance is demonstrated by

compliance with the PM_{10} testing requirement of Specific Condition 385. [Regulation 19, §19.901 and 40 CFR Part 52 Subpart E]

385. The permittee shall continue to conduct continuous sampling of the stack gas at SN-41 to produce two 12-hr composite samples each day to demonstrate compliance with the limits in Specific Conditions 382 and 384. The permittee shall maintain a 30-day rolling average of the PM_{10} emissions at SN-41 to demonstrate compliance with the limits in Specific Conditions 382 and 383.

Each 12-hour composite sample shall be analyzed using Method EDCC-330.2 (to determine ammonia concentration) and EPA Method 300.0 "Determination of Inorganic Anions by Ion Chromatography" (to determine nitrate concentration). EDCC's analysis procedure for ammonia shall be consistent with Method 4500-NH_3 from "Standard Methods for the Examination of Water and Wastewater, 19th Edition". The data from the analyses shall be entered into an Excel spreadsheet on a daily basis to calculate the mass concentrations of ammonia (as NH_3) and condensable particulate (as NH_4NO_3) in the vapor stream leaving SN-41. Total vapor flow from process equipment controlled by SN-41 (i.e., Auxiliary Concentrator, E2 Low Concentrator, Fresh Neutralizer, Off-Gas Neutralizer, and the #4 Neutralizer) shall be assumed to be at maximum rates for initial calculations/compliance demonstration purposes. Should spreadsheet results indicate an exceedance of the permitted rate for ammonia/particulate matter, EDCC shall calculate the actual total vapor flow rate by mass balance around the operations that feed vapors to SN-41 to verify compliance, based on the following:

- The vapor stream from the Auxiliary Concentrator will be considered to be at its maximum rate if the unit is in operation.
- The vapor stream from the Low Concentrator will be calculated based on the measured prill production rate and solution concentrations.
- Vapor flow from the neutralizers will be calculated based on the acid and ammonia feed rates and the acid and product solution concentrations.

The permittee shall maintain an emission inventory spreadsheet for particulate matter and ammonia emissions from SN-41. The spreadsheet shall contain each 12-hour composite sample result and shall be used to maintain a daily, 24-hour average result to demonstrate compliance with the lb/hr emission limits and a 12-month rolling total to demonstrate compliance with the annual emission limits. A valid 12-hour period is defined as beginning at 8:00 a.m. and at 8:00 p.m. This information shall be submitted in accordance with General Provision 7.

[Regulation 19, §19.702 and §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

SN-06
Ammonium Nitrate Prill Tower Fans

Source Description

The E2 Ammonium Nitrate Prill Tower Fans (SN-06) are composed of three fans located in each of the two independent ammonium nitrate prill towers (North and South). E2 Plant prilling operations are accomplished by valving a 99% ammonium nitrate solution from a head tank through a prill plate. The prill plate breaks up the solution stream into droplets that fall through one of the two towers. An air stream is pulled through the tower shrouds to remove the majority of the ammonium nitrate emissions generated as the solution is broken into droplets at the prill plates. The air stream from inside the shroud is exhausted through the Brinks Scrubber (SN-05) to control particulate emissions.

Specific Conditions

386. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-06 is demonstrated by compliance with Specific Conditions 376, 377, 378, and 379, and the reporting required in Plantwide Condition 7. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
06	E2 Ammonium Nitrate Prill Tower Fans	PM_{10}	67.0	*

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

387. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-06 is demonstrated by compliance with Specific Conditions 377, 378, and 379, and the reporting required in Plantwide Condition 7. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
06	E2 Ammonium Nitrate Prill Tower Fans	PM	67.0	*

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

388. The permittee shall not exceed 25% opacity from SN-06 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-06 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

389. The permittee shall reduce the emissions specified in Specific Conditions 386 and 387 for SN-06 by routing the emissions to SN-05 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after re-routing the emissions from SN-06 to SN-05 as specified in Specific Conditions 104 and 105, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-19
E2 Plant Barometric Tower

Source Description

A wooden structure operating similar to a cooling tower is used to create a "barometric leg" for the high concentrator (located at the top of the E2 Plant Prill Tower) to concentrate ammonium nitrate from 95% strength to greater than 99%. The high concentrator operates under a vacuum and non-condensables are pulled through the barometric leg to this dedicated barometric tower (SN-19). The barometric tower uses weak ammonium nitrate (~20%) process water as the circulation media. Particulate matter emissions occur as a result of particulate entrained in the water vapor mist that is emitted (sprayed) from the tower. Ammonia emissions also occur due to the water containing ammonium nitrate in solution.

Specific Conditions

390. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-19 is demonstrated by compliance with Specific Conditions 377 and 378. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
19	E2 Plant Barometric Tower	PM_{10}	0.5	*

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

391. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-19 is demonstrated by compliance with Specific Conditions 377 and 378. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
19	E2 Plant Barometric Tower	PM NH_3	0.5 4.10	* 17.70

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

392. The permittee shall not exceed 15% opacity from SN-19 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-19 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

393. The permittee shall reduce the emissions at SN-19 to a level no greater than the levels specified in Specific Conditions 118 and 119 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-19 to the levels specified in Specific Conditions 118 and 119, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-28
E2 Plant HDAN Loading

Source Description

E2 Plant HDAN produced at the E2 Plant is loaded in to rail cars or trucks. Particulate matter emissions occur as the HDAN is being loaded into the rail cars or trucks.

Specific Conditions

394. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-28 is demonstrated by compliance with Specific Conditions 377 and 378. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
28	E2 Plant HDAN/LDAN Loading	PM_{10}	1.1	4.8

395. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour limits are based on engineering estimates, maximum capacity, and stack testing results. Compliance with the emission limits for SN-28 is demonstrated by compliance with Specific Conditions 377 and 378. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
28	E2 Plant HDAN/LDAN Loading	PM	1.1	4.8

396. The permittee shall not exceed 25% opacity from SN-28 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-28 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-34
E2 Plant Solution Reactor

Source Description

A 35% nitric acid/magnesium oxide solution is created by reacting 56% nitric acid with magnesium oxide through agitation. Approximately 0.5% of the magnesium oxide is contained in the final ammonium nitrate product. Each batch takes two hours to make 2.905 tons of nitric acid/magnesium oxide solution. This solution reactor, which does not contain any pollution control equipment, has the capability of producing twelve batches of E2 solution a day while the E2 Ammonium Nitrate Plant is running at its maximum rate. The solution leaves the reactor, where it is filtered to remove any excess magnesium oxide and other trace particulates, and is stored in a heated tank as 35% solution. The solution is pumped to the inlet of the Low Concentrator.

Specific Conditions

397. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on maximum capacity. The tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 377 and 378. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
34	E2 Plant Solution Reactor	PM_{10}	0.9	3.0

398. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on maximum capacity. The tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 377 and 378. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
34	E2 Plant Solution Reactor	PM	0.9	3.0

399. The permittee shall not exceed 20% opacity from SN-34 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-34 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

KT Ammonium Nitrate Plant

SN-14
LDAN Prill Tower

Source Description

To be sold in final product form, LDAN at the KT Plant is prilled in a prilling tower. A 97% ammonium nitrate solution is mixed with a proprietary additive in a head tank. The prilling operation is accomplished by dispersing the ammonium nitrate solution downward in the tower through a spray nozzle. Long residence times and low air rates contribute to the production of high quality prills, which generate lower particle fines and therefore, lower particulate matter emissions. Four fans control the temperature of the prills leaving the bottom of the prilling tower. This air cools and solidifies the ammonium nitrate droplets into solid prills. The air stream and entrained particles are vented to the atmosphere through chimneys on top of the tower.

The uncontrolled emissions from SN-14 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned source is regulated under the CAM Rule because it meets the following criteria: (1) the unit is subject to emission limitations for PM_{10}, (2) the source is equipped with a control device, and (3) the unit has potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for this source. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limit at this source.

Specific Conditions

400. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 38.5 tons per hour of ammonium nitrate production. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 404, 405, 406, and 407, and the reporting required in Plantwide Condition 7. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
14	KT LDAN Prill Tower	PM_{10} $PM_{2.5}$	44.2	*

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

401. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 38.5 tons per hour of ammonium nitrate production. Compliance with the emission limits is demonstrated by

compliance with Specific Conditions 404, 405, 406, and 407, and the reporting required in Plantwide Condition 7. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
14	KT LDAN Prill Tower	PM	44.2	*

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

402. The permittee shall reduce the emissions at SN-14 to a level no greater than the levels specified in Specific Conditions 127 and 128 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-14 to the levels specified in Specific Conditions 127 and 128, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

403. The permittee shall not exceed 15% opacity from SN-14 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-14 is demonstrated by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

404. The permittee shall not manufacture in excess of 252,000 tons of ammonium nitrate per rolling 12-month total through the KT Ammonium Nitrate Plant. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311 and 40 CFR 70.6]

405. The permittee shall keep records of the ammonium nitrate production manufactured in the KT Ammonium Nitrate Plant. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

406. The permittee shall have a third party stack test the PM_{10} emissions from SN-14 within 180 days of issuance of Permit 0573-AOP-R12, and annually thereafter. The stack test shall be performed using EPA Reference Method 201A or 5, EPA Reference Method 202, and a method approved in advance by the Department. The permittee shall maintain the approved method with the permit. By using Method 5 for PM_{10}, the facility will assume all collected particulate is PM_{10}. PM_{10} emission rates measured during this testing shall be less than the permitted emission rates specified in Specific Condition # 127. This unit shall be operated at 90% or more of maximum capacity when the stack test is performed. Emission testing results shall be extrapolated to correlate with 100% of

the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. 90% of maximum capacity is defined as:

a. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
b. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
c. The moisture content of the product exiting the dryer must be less than 0.1%.

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

407. The permittee shall calculate PM_{10} emissions for Plantwide Condition #7 from the KT LDAN Prill Tower (SN-14), the KT Plant Dryer/Cooler (SN-15), and the KT Plant Brinks Scrubber (SN-21) using a total emission factor of 1.13 lb of PM_{10} per ton of ammonium nitrate produced at the KT Plant. These records shall be updated by the 15th of the month following the month which the records represent. These records shall be kept on site and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

408. The permittee shall reduce the emissions at SN-14 to a level no greater than the levels specified in Specific Conditions 127 and 128 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-14 to the levels specified in Specific Conditions 127 and 128, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-15, SN-18, and SN-21
KT Plant Dryer, Baghouse, and Scrubber

Source Description

Prills exiting the bottom of the KT LDAN Prill Tower (SN-14) are conveyed to a predryer and dryer. The predryer and dryer exhaust air streams are drawn by a common fan concurrent to the direction of the prill and blown to a wet scrubber. The scrubber efficiency is increased by injecting a portion of the scrubbing solution into the fan system. The wet scrubber exhaust, which contains ammonia and particulate matter, is vented directly to the atmosphere through a stack designated as SN-15.

An external coating of high melting point organic material and talc is added to the LDAN to improve the storage and flow of the final product. The talc is stored in an enclosed silo that pneumatically feeds into a bulk talc hopper. Both the silo and the hopper are equipped with a baghouse (SN-18) to minimize particulate matter emissions. The silo baghouse only operates when the talc is being blown into the silo during the unloading of talc when delivered to the plant. The baghouse at the hopper operates when talc is being added to the LDAN. The baghouses do not operate at the same time.

During LDAN production at the KT Plant, ammonium nitrate solution exits a neutralizer and is pumped into a 50 ton solution storage tank. The ammonium nitrate solution (composed of 90% ammonium nitrate and 10% water) is in molten form at this stage in the process. In the storage tank, the ammonium nitrate solution is blended with "recycled" ammonium nitrate solution, which has been concentrated in the auxiliary concentrator. The ammonium nitrate must be concentrated to 97.5% prior to prilling operations. For this to occur, the ammonium nitrate solution is transferred from the 50 ton tank to a dehydrator. The dehydrator air is blown through the solution to remove excess water. The exhaust stream from the dehydrator is directed to the Brinks Scrubber (SN-21) prior to being vented to the atmosphere.

The uncontrolled emissions from SN-15, SN-18, and SN-21 fulfill the applicability criteria of the Compliance Assurance Monitoring (CAM) Rule (40 Code of Federal Regulations (CFR) Part (§) 64). Accordingly, the (CAM) Plan for the facility is provided in Appendix G. Per §64.2(a), the aforementioned sources are regulated under the CAM Rule because it meets the following criteria: (1) the units are subject to emission limitations for PM_{10}, (2) the sources are equipped with a control device, and (3) the units have potential pre-control emissions of PM_{10} that exceed the applicable major source threshold. In accordance with §64.3, EDCC has developed a CAM Plan for these sources. The Plan establishes the operating parameters that will be monitored in order to demonstrate compliance with the PM_{10} emission limits at these sources.

Specific Conditions

409. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 38.5 tons per hour of ammonium nitrate production. Compliance with the emission limits for SN-15 is demonstrated by compliance with Specific Conditions 404, 405, 407, 413, and 0, and the reporting required in Plantwide Condition 7. Compliance with the emission limits for SN-18 is demonstrated by compliance with Specific Conditions 404, 405, and 0, and the reporting required in Plantwide Condition 7. Compliance with the emission limits for SN-21 is demonstrated by compliance with Specific Conditions 404, 405, 407, 413, and 0, and the reporting required in Plantwide Condition 7. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
15	KT Plant Dryer	PM_{10}	17.0	*
18	KT Plant Clay Baghouse	PM_{10}	1.0	*
21	KT Plant Brinks Scrubber	PM_{10}	3.0	*

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

410. The permittee shall not exceed the emission rates set forth in the following table. The hourly emission limits are based on maximum capacity of 38.5 tons per hour of ammonium nitrate production. Compliance with the emission limits for SN-15 is demonstrated by compliance with Specific Conditions 404, 405, 407, 414, and 0, and the reporting required in Plantwide Condition 7. Compliance with the emission limits for SN-18 is demonstrated by compliance with Specific Conditions 404, 405, and 0, and the reporting required in Plantwide Condition 7. Compliance with the emission limits for SN-21 is demonstrated by compliance with Specific Conditions 404, 405, 407, 414, and 0, and the reporting required in Plantwide Condition 7. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
15	KT Plant Dryer	NH_3 PM	18.00 17.0	75.60 *
18	KT Plant Clay Baghouse	PM	1.0	*
21	KT Plant Brinks Scrubber	NH_3 PM	30.00 3.0	126.00 *

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.

411. The permittee shall reduce the emissions at SN-15 and SN-21 to a level no greater than the levels specified in Specific Conditions 135 and 136 before the contemporaneous

netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-15 and SN-21 to the levels specified in Specific Conditions 135 and 136, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

412. The permittee shall not exceed 5% opacity from SN-18, 10% opacity from SN-21, and 20% opacity from SN-15, as measured by EPA Reference Method 9. Compliance with the opacity limits set forth in this Specific Condition will be shown by compliance with Plantwide Condition 10. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

413. The permittee shall have a third party annually stack test the PM_{10} emissions from SN-15 using EPA Reference Method 201A or 5, and EPA Reference Method 202. The permittee shall have a third party stack test the PM_{10} emissions from SN-21 within 180 days of issuance of Permit 0573-AOP-R12, and annually thereafter. The stack test shall be performed using EPA Reference Method 201A or 5, EPA Reference Method 202, and a method approved in advance by the Department. The permittee shall maintain the approved method with the permit. By using Method 5 for PM_{10}, the facility will assume all collected particulate is PM_{10}. PM_{10} emission rates measured during this testing shall be less than the permitted emission rates specified in Specific Condition 409. These units shall be operated at 90% or more of maximum capacity when the stack tests are performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. For SN-15 and SN-21, 90% of maximum capacity is defined as:

a. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
b. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
c. The moisture content of the product exiting the dryer must be less than 0.1%.

[Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

414. The permittee shall have a third party annually stack test the NH_3 emissions from SN-21 using a method approved in advance by the Department to capture ammonia, and the NH_3 emissions shall be less than the permitted emission rates specified in Specific Condition # 136. The permittee shall maintain the approved method with the permit. For SN-21, if the stack tests pass three consecutive years of annual testing, the permittee shall perform

stack test once every three years. Upon failure of a stack test, the permittee shall stack test annually until three consecutive years yield results less than the permitted emission rates specified in Specific Condition 410. The permittee shall have a third party stack test once every five years the NH_3 emissions from SN-15 using a EPA Method 5 modified to simultaneously capture ammonia, and the NH_3 emissions shall be less than the permitted emission rates specified in Specific Condition 410. For SN-15, upon failure of a stack test, the permittee shall stack test annually until two consecutive years are less than the permitted emission rates specified in Specific Condition 410. The units shall be operated at 90% or more of maximum capacity when the stack tests are performed. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. The 90% of maximum capacity is defined as:

a. For SN-15, 90% of the maximum capacity during NH_3 testing is defined as:

    i. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
    ii. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
    iii. The moisture content of the product exiting the dryer must be less than 0.1%.

b. For SN-21, 90% of maximum capacity during NH_3 testing is defined as:

    i. 90% of the maximum capacity of the prill tower on an ammonium nitrate production basis.
    ii. Maximum input rate to dehydrator (i.e. ammonium nitrate solution) is 105 gpm; therefore, 90% would be 94.5 gpm.
    iii. The product exit temperature at the prill tower at the time of the test must be less than 180°F.
    iv. The moisture content of the product exiting the dryer must be less than 0.1%.

[Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

415. The KT Brinks Scrubber (SN-21), the KT Plant Dryer Scrubber (SN-15), and the KT Plant Clay Baghouse (SN-18) shall be kept in good working condition at all times and shall meet the conditions shown in the following table when the plant is operating. The monitoring parameters for SN-15, and SN-18, and SN-21 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data shall be recorded every 4 hours when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parameter to be outside the range, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and be available to Department personnel upon request. The permittee shall submit a summary of data including all information as required in the General Provision 8 if applicable. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Parameter	Units	Operation Limits
15	KT Plant Dryer Scrubber	Scrubber Liquor pH	-	0.5 – 4.5
		Liquid Flow Rate (combination of fan and ductwork)	gal/min	80 (minimum)
		Amperage	amps	290 (minimum)
18	KT Plant Baghouse	Gas Pressure Drop	in. H_2O	0.5 - 8.0
21	KT Brinks Scrubber	Liquid Gas Pressure to Top Spray Nozzles	psig	80 - 100
		Gas Pressure Drop Across Unit	in. H_2O	2.5 (minimum)
		pH	-	0.5 – 4.5

416. The permittee shall calculate PM_{10} emissions for Plantwide Condition 7 from the KT LDAN Prill Tower (SN-14), the KT Plant Dryer/Cooler (SN-15), and the KT Plant Brinks Scrubber (SN-21) using a total emission factor of 1.13 lb of PM_{10} per ton of ammonium nitrate produced at the KT Plant. These records shall be updated by the 15th of the month following the month which the records represent. These records shall be kept on site and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

417. The permittee shall reduce the emissions at SN-18 and SN-21 to a level no greater than the levels specified in Specific Conditions 135 and 136 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The

facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-14 to the levels specified in Specific Conditions 135 and 136, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

418. The permittee shall reduce the PM emissions at SN-15 to a level no greater than the levels specified in Specific Conditions 135 and 136 before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after reducing the emissions at SN-14 to the levels specified in Specific Conditions 135 and 136, and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

SN-27
KT Plant LDAN Loading

Source Description

LDAN produced at the KT Plant is loaded into rail cars or trucks. Particulate matter emissions occur as the LDAN is being loaded into the rail cars or trucks.

Specific Conditions

419. The permittee shall not exceed the emission rates set forth in the following table. The emission limits are based on maximum capacity. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 404 and 405. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	Lb/hr	tpy
27	KT Plant LDAN Loading	PM_{10}	0.6	2.6

420. The permittee shall not exceed the emission rates set forth in the following table. The emission limits are based on maximum capacity. Compliance with the emission limits is demonstrated by compliance with Specific Conditions 404 and 405. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
27	KT Plant LDAN Loading	PM	0.6	2.6

421. The permittee shall not exceed 10% opacity from SN-27 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-27 is demonstrated by compliance with Plantwide Condition 10. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

Mixed Acid Plant

SN-44
Mixed Acid Plant Scrubber

Source Description

EDCC manufactures mixed acid by mixing 15% - 30% oleum (concentrated sulfuric acid) and/or 98% sulfuric acid with 98% nitric acid. The 15% - 30% oleum is purchased from a vendor and delivered to EDCC by railcar or tanker truck, while the 98% sulfuric acid will come from EDCC's Sulfuric Acid Plant, and the 98% nitric acid will come from EDCC's Nitric Acid Plant. The manufactured mixed acid is stored in the product storage tank or the mixing tank until it is loaded into a railcar or tanker truck. Air emissions from the tanks, the unloading of oleum, and the loading/unloading of the mixed acid into tank cars and/or trucks will be routed to the scrubber (SN-44) prior to being released to the atmosphere.

This scrubber is not subject to CAM because the scrubber is not used to control the NO_x emissions from this source.

Specific Conditions

422. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Conditions 425 through 429. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
44	Mixed Acid Plant Scrubber	NO_x	0.4	1.7

423. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 425 through 429. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
44	Mixed Acid Plant Scrubber	SO_3	0.05	0.18
		H_2SO_4	0.05	0.18
		HNO_3	0.20	0.90

424. The permittee shall not exceed 20% opacity from SN-44 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-44 is demonstrated by compliance with Plantwide Condition 10. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

425. The permittee shall offload no more than 394,200 tons of Oleum into the Oleum Storage Tank per consecutive 12 month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

426. The permittee shall not use Oleum in excess of 30% in strength (SO_3 concentration). [Regulation 19, §19.705, A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311, and 40 CFR 70.6]

427. The permittee shall not produce more than 219,000 tons of mixed acid per consecutive 12-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

428. The permittee shall maintain monthly records of the amount of Oleum offloaded into the Oleum Storage Tank, the percent strength of the Oleum, and the amount of mixed acid produced. These records shall be updated on monthly basis, kept on site, and made available to Department personnel upon request. An annual total and each month's individual total shall be submitted to the Department in accordance with General Provision 7. [Regulation 19, §19.705, A.C.A. 8-4-203 as referenced by 8-4-304 and 8-4-311, and 40 CFR 70.6]

429. The permittee shall have a third party stack test SN-44 once every five years for HNO_3, H_2SO_4, SO_3, and NO_X emissions using an approved method, and the emissions shall be less than the hourly limit specified in Specific Conditions 422 and 423. Upon failure of a stack test, the permittee shall stack test annually until two consecutive years are below the permitted emission rates. During stack testing, the mixed acid plant shall be operating at a rate greater than or equal to 90% capacity. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

430. The Mixed Acid Scrubber shall be kept in good working condition at all times. The following monitoring parameters for SN-44 shall be measured and recorded daily. All hourly data recorded during a calendar day shall be averaged to demonstrate compliance with the daily limit. A valid daily period is defined as the period from 12 a.m. to 12 a.m. where at least 67% of the data or at least 16 hourly readings collected in the 24-hour period when the plant is operating must be recorded. All data recorded once per 12-hour shift when the plant is operating shall be averaged to demonstrate compliance with the daily limit. In the event that a daily parameter is outside the range, the permittee shall take immediate action to identify the cause of the parameter to be outside the range, implement corrective action, and document that the parameter was back inside the range following corrective action by the end of the next 24-hour period. The results shall be kept on site and made available to Department personnel upon request. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Parameter	Units	Operation Limits
44	Mixed Acid Plant Scrubber	Scrubber Liquid Flow Rate	gal/min	5.0 (minimum)
		Gas Pressure Drop Across Unit	in. H_2O	10 - 35
		Scrubber liquid pH	-	0.5 – 7.5

Natural Gas Fired Boilers

SN-16A and SN-16B
Natural Gas Fired Boilers

Source Description

Boilers No. 2 (SN-16A) and No. 4 (SN-16B) are used to supply steam throughout the various plants at the facility. Both units are fired only with natural gas and each has a design heat input of 145 MMBtu/hr. One boiler can provide steam adequately for the entire facility and only one boiler is allowed to be in operation per the netting this facility underwent in 1990 to avoid PSD (except when they are being switched). It requires about 24 hours for an inactive boiler to warm-up and to take the plant loads. Both boilers will be operated during these switching periods.

Since the boilers at this facility were constructed in 1944, New Source Performance Standards 40 CFR 60 Subparts D, Da, Db, and Dc are not applicable.

Specific Conditions

431. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of each boiler and the tons per year emission rate limits are based on the maximum capacity of one boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 434 and 435. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
16A	Boiler No. 2	PM_{10}	1.1	*
		SO_2	0.1	0.4
		VOC	0.8	3.5
		CO	12.0	52.3
		NO_x	39.8	174.2
16B	Boiler No. 4	PM_{10}	1.1	*
		SO_2	0.1	**
		VOC	0.8	**
		CO	12.0	**
		NO_x	39.8	**

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.
** - SO_2, VOC, CO, and NO_x annual emissions are bubbled together for SN-16A and SN-16B.

432. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour emission rate limits are based on engineering estimates and the maximum capacity of each boiler and the tons per year emission rate limits are based on maximum capacity of one boiler. Compliance with this Specific Condition is demonstrated by compliance with Specific Conditions 434 and 435. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
16A	Boiler No. 2	PM	1.1	*
		Hexane	0.3	1.20
16B	Boiler No. 4	PM	1.1	*
		Hexane	0.3	**

* - Included in a Plantwide limit of 281.0 tpy shown in Plantwide Condition 7.
** - Hexane annual emissions are bubbled together for SN-16A and SN-16B.

433. The permittee shall not exceed 5% opacity from SN-16A and SN-16B as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-16A and SN-16B are demonstrated by compliance with Specific Condition 434. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

434. The permittee shall burn only pipeline quality natural gas in Boiler No. 2 (SN-16A) and Boiler No. 4 (SN-16B). [Regulation 19, §19.705, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

435. The permittee shall keep records of the operating hours when both boilers are operating. The permittee shall not operate the two (2) boilers simultaneously for more than 240 hours per year. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

436. The permittee shall cease operations at SN-16A and SN-16B before the contemporaneous netting time period ends as indicated in the application for Permit 0573-AOP-R16. The facility shall notify the Department in writing within thirty (30) days after ceasing operations at SN-16A and SN-16B and shall contain the date that the contemporaneous time period ended. [Regulation 19, §19.705 and §19.901, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Miscellaneous Operations

SN-25
Gasoline Storage Tank

Source Description

This 2,000 gallon aboveground storage tank (SN-25) is used to fuel facility vehicles and equipment.

Specific Conditions

437. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 438 and 439. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
25	Gasoline Storage Tank (2000 Gallon)	VOC	16.9	1.4

438. The permittee shall not use in excess of 40,000 gallons of gasoline per rolling 12-month total. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

439. The permittee shall keep records of the gasoline usage through the gasoline storage tank. These records shall contain each month's total and a rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. This information shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 52, Subpart E]

NESHAP Requirements

440. SN-25 is subject to 40 CFR Part 63, Subpart CCCCCC. The permittee shall comply with all applicable provisions of 40 CFR Part 63, Subpart CCCCCC which includes, but is not limited to, Specific Condition 441. [Regulation 19, §19.304 and 40 CFR Part 63, Subpart CCCCCC]

441. §63.11116 – Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline.

(a) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;
(2) Clean up spills as expeditiously as practicable;
(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;
(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

(b) You are not required to submit notifications or reports, but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

[Regulation 19, §19.304 and 40 CFR §63.11116]

SN-26
Ammonium Nitrate (90% Solution) Storage Tanks

Source Description

Six above ground storage tanks (SN-26) are used to store 90% ammonium nitrate solution for prilling operations. Four (4) of the tanks are 650,000 gallons, and two (2) of the tanks are 1,200,000 gallons for a total storage of 5,000,000 gallons. Air emissions occur due to steam line heaters degrading the ammonium nitrate solution to ammonia.

Specific Conditions

442. The permittee shall not exceed the emission rates set forth in the following table. The pound per hour emission rate limit is based on maximum capacity and tons per year emission rate limits are based on compliance with Specific Conditions 377 and 378. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
26	Ammonium Nitrate Storage Tanks	NH_3	1.60	0.90

SN-31
Frick Ammonia Compressors

Source Description

Fugitive emissions occur from the handling of ammonia in the Frick Compressor Building. Standard Organic Chemical Manufacturing Industry (SOCMI) emission factors for compressors, pumps, valves, and flanges in ammonia service were used to estimate the fugitive ammonia emissions from the Frick Compressor Building.

Specific Conditions

443. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on maximum capacity. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
31	Frick Ammonia Compressors	NH_3	0.50	2.00

SN-32
Ammonia Storage/Distribution Losses

Source Description

Fugitive emissions occur from the handling and distribution of ammonia. Standard Organic Chemical Manufacturing Industry (SOCMI) emission factors for compressors, pumps, valves, and flanges in ammonia service were used to estimate the fugitive ammonia emissions from the Ammonia Storage/Distribution.

Specific Conditions

444. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on maximum capacity. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
32	Ammonia Storage/Distribution Losses	NH_3	1.30	5.70

SN-35
Magnesium Oxide Silo Baghouse

Source Description

The magnesium oxide silo baghouse (SN-35) pneumatically receives magnesium oxide powder from semi-truck transport and/or railcar and controls particulate matter from the unloading and storage operations. The baghouse is situated on top of the silo structure which is approximately 50 feet tall.

Specific Conditions

445. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant as limited by Specific Condition 377. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition 378. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
35	Magnesium Oxide Silo Baghouse	PM_{10}	2.0	8.8

446. The permittee shall not exceed the emission rates set forth in the following table. The pounds per hour and tons per year emission rate limits are based on yearly throughput through the E2 Ammonium Nitrate Plant as limited by Specific Condition 377. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition 378. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
35	Magnesium Oxide Silo Baghouse	PM	2.0	8.8

447. The permittee shall not exceed 5% opacity from SN-35 as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-35 is demonstrated by compliance with Plantwide Condition 10. [Regulation 19, §19.503 and 40 CFR 52, Subpart E]

448. The permittee shall have a third party test the particulate emissions (PM, PM_{10}, and $PM_{2.5}$) from SN-35. The stack test shall be performed using EPA Reference Method 201A or 5. By using Method 5 for PM_{10} and $PM_{2.5}$, the facility will assume all collected particulate is PM_{10} and $PM_{2.5}$. These units shall be operated at 90% or more of maximum capacity when the stack tests are performed. Emission testing results shall be

extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate until a subsequent test can be successfully conducted at 90% or above. [Regulation 19, §19.702 and 40 CFR Part 52, Subpart E]

SN-40
Ammonium Nitrate Solution Loading

Source Description

EDCC ships ammonium nitrate solution to customers via trucks and railcars. The content of the solution ranges from 83% to 90% ammonium nitrate. Ammonia emissions occur as a result of the loading of the trucks and railcars.

Specific Conditions

449. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition 450 and 451. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
40	Ammonium Nitrate Solution Loading	NH_3	3.80	4.70

450. The permittee shall not load more than 468,660 tons per rolling 12-month total of ammonium nitrate solution into railcars and/or trucks. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

451. The permittee shall keep records of the amount of ammonium nitrate solution loaded into railcars and/or trucks. These records shall contain each month's total and the rolling total for the previous 12 months. These records shall be updated by the 15th of the month following the month which the records represent. These records shall be kept on site, made available to the Department personnel upon request, and submitted in accordance with General Provision 7. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-62
Haul Road Fugitives

Source Description

Transport trucks and facility vehicles operate on paved and unpaved roads at the facility. Particulate matter emissions occur due to the vehicle traffic (SN-62).

Specific Conditions

452. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 454 and 455. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
62	Haul Road Fugitives	PM_{10}	1.5	4.4

453. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 454 and 455. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
62	Haul Road Fugitives	PM	6.7	20.8

454. Dust suppression activities should be conducted in a manner and at a rate of application that will not cause runoff from the area being applied. Best Management Practices (40 CFR §122.44(k)) should be used around streams and waterbodies to prevent the dust suppression agent from entering Waters of the State. Except for potable water, no agent shall be applied within 100 feet of wetlands, lakes, ponds, springs, streams, or sinkholes. Failure to meet this condition may require the permittee to obtain a National Pollutant Discharge Elimination System (NPDES) permit in accordance with 40 CFR §122.1(b). [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

455. The permittee shall implement a fugitive emission dust control plan to control dust emissions from the roadways. The permittee shall submit for Department approval a fugitive dust control plan for the roadways six months after issuance of Air Permit 0573-AOP-R16. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-65
Emergency Water Pump

Source Description

An 80 Hp emergency water pump engine is on site in case of emergencies.

Specific Conditions

456. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 460 through 462. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
65	80 Hp Emergency Water Pump	PM_{10}	0.2	0.1
		SO_2	0.2	0.1
		VOC	0.2	0.1
		CO	0.6	0.1
		NO_x	2.5	0.2

457. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 460 through 462. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
65	80 Hp Emergency Water Pump	PM	0.2	0.1

458. The permittee shall not exceed 20% opacity from SN-65 as measured by EPA Reference Method 9. Compliance with this Interim Condition shall be demonstrated by compliance with Specific Condition 459. [Regulation 18, §18.501, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

459. The permittee shall conduct annual visible emissions observations as a method of compliance verification for the opacity limit assigned for SN-65. Observations shall be conducted by someone trained in EPA Reference Method 9. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

a. Take immediate action to identify the cause of the visible emissions,
b. Implement corrective action, and
c. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9 for point sources and in accordance with EPA Method 22 for non-point sources. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.
d. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

e. The time and date of each observation/reading,
f. Any observance of visible emissions appearing to be above permitted limits or any Method 9 reading which indicates exceedance,
g. The cause of any observed exceedance of opacity limits, corrective actions taken, and results of the reassessment, and
h. The name of the person conducting the observation/reading.

460. The permittee shall not operate the emergency water pump (SN-65) in excess of 100 hours per calendar year. If the permittee operates SN-65 in excess of 100 hours during any calendar year, the permittee shall provide the necessary documentation to demonstrate that the engine still qualifies as an emergency engine as outlined in §63.6640(f). [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

461. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Conditions 460. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site and made available to Department personnel upon request. A calendar year total and each individual month's data shall be recorded. [Regulation 19, §19.705 and 40 CFR 52, Subpart E]

462. SN-65 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all applicable provisions of 40 CFR Part 63, Subpart ZZZZ no later than May 3, 2013, which includes, but is not limited to, Specific Conditions 463 through 475. [Regulation 19, §19.304 and 40 CFR Part 63, Subpart ZZZZ]

463. You must be in compliance with the emission limitations, operating limitations, and other requirements in 40 CFR Part 63, Subpart ZZZZ that apply to you at all times. [Regulation 19, §19.304 and 40 CFR Part 63, §63.6605(a)]

464. At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [Regulation 19, §19.304 and 40 CFR Part 63, §63.6605(b)]

465. The permittee shall operate and maintain SN-65, and after-treatment control device (if any), according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(e)]

466. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(f)]

467. If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to 40 CFR Part 63, Subpart ZZZZ apply. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(h)]

468. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to 40 CFR Part 63, Subpart ZZZZ or in items 1 or 4 of Table 2d to 40 CFR Part 63, Subpart ZZZZ, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to 40 CFR Part 63, Subpart ZZZZ. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to 40 CFR Part 63, Subpart ZZZZ. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business

days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6625(i)]

469. As stated in §63.6602 and §63.6640, the permittee shall comply with the following requirements for existing stationary RICE located at major source of HAP emissions:

For each	The permittee shall meet the following requirement, except during periods of startup	During periods of startup the permittee shall
SN-65[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2c of Subpart ZZZZ, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.
[2] Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of Subpart ZZZZ.
[3] Source can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[Regulation 19, §19.304, and 40 CFR Part 63, §63.6602, §63.6640(a), and Table 2c]

470. As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each	Complying with the following requirement:	The permittee must demonstrate continuous compliance by:
SN-65	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[Regulation 19, §19.304, and 40 CFR Part 63, §63.6640(a), and Table 6]

471. You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to 40 CFR Part 63, Subpart ZZZZ that apply to you. These instances are deviations from the emission and operating limitations in 40 CFR Part 63, Subpart ZZZZ. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6640(b)]

472. If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of §63.6640. In order for the engine to be considered an emergency stationary RICE under 40 CFR Part 63, Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of §63.6640, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of §63.6640, the engine will not be considered an emergency engine under 40 CFR Part 63, Subpart ZZZZ and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of §63.6640 for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by

paragraphs (f)(3) and (4) of §63.6640counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of §63.6640. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of §63.6640. Except as provided in paragraphs (f)(4)(i) and (ii) of §63.6640, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[Regulation 19, §19.304 and 40 CFR §63.6640(f)]

473. If the permittee must comply with the emission and operating limitations, the permittee must keep the records described in paragraphs (a)(1) through (a)(5), and (b)(1) through (b)(3) of 40 CFR Part 63, Subpart ZZZZ. These records include, but are not limited to, the following:

a. A copy of each notification and report that the permittee submitted to comply with 40 CFR Part 63, Subpart ZZZZ, including all documentation supporting any Initial Notification or Notification of Compliance Status that the permittee submitted, according to the requirement in §63.10(b)(2)(xiv).
b. Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.
c. Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).
d. Records of all required maintenance performed on the air pollution control and monitoring equipment.

e. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[Regulation 19, §19.304, and 40 CFR Part 63, §63.6655(a)(1) through (a)(5)]

474. The permittee must keep the records required in Table 6 of 40 CFR Part 63, Subpart ZZZZ to show continuous compliance with each emission or operating limitation that applies to the permittee. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6655(d)]

475. The permittee must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that the permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's own maintenance plan. [Regulation 19, §19.304, and 40 CFR Part 63, §63.6655(e)]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

El Dorado Chemical Company will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19 §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) calendar days after completing the testing. [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

4. The permittee must provide:

   e. Sampling ports adequate for applicable test methods;
   f. Safe sampling platforms;
   g. Safe access to sampling platforms; and
   h. Utilities for sampling and testing equipment.

   [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19 §19.303 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

7. The permittee must complete a monthly production/emission inventory spreadsheet for particulate emissions from sources SN-05, SN-06, SN-14, SN-15, SN-16A/B, SN-18, SN-19, and SN-21 (those listed in the permit in 1989) in order to keep track of the

monthly particulate emissions from these sources. The permittee shall not exceed the 12 month rolling total of 281.0 tons that was accepted for PSD offsetting in 1989. The Plantwide PM limit of 281.0 ton/year does not include the quantity of condensable particulate measured through the back-half sampling train procedure of EPA Reference Method 5. An exceedance of this 12 month rate shall constitute a violation of PSD regulations. The permittee shall notify this Department immediately if the 12 month rolling total limit is exceeded. [Regulation 19, §19.901 and 40 CFR Part 52, Subpart E]

8. The permittee must submit a 12 month summary of the monthly particulate emissions in accordance with General Provision 7. [Regulation 19, §19.901 and 40 CFR Part 52, Subpart E]

9. The permittee shall maintain and employ the Startup, Shutdown, and Malfunction Plan for SN-07, SN-08, SN-09, SN-22, SN-13, and SN-41 as required by Air Permit 0573-AOP-R8. If the Department requests a review of the SSM, the permittee will make the SSM available for review. The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. The SSMP shall include requirements to record any downtime, malfunction, startup, or shutdown. Any deviations from a permit requirement shall be reported to the Department in accordance with General Provision 8 with the exception that exceedences to which procedures exist in the SSM Plan may be reported as part of the semi-annual reporting. The Department reserves the right to review any such exceedences in accordance with provisions of §19.601. [Regulation 18, §18.801 and §18.1004, Regulation 19 §19.601, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. Daily observations of the opacity from SN-05 thru SN-10, SN-13 thru SN-15, SN-18, SN-19, SN-21, SN-22, SN-27, SN-28, SN-34, SN-35, SN-41, SN-44, and SN-48 shall be conducted by a person trained, but not necessarily certified, in EPA Reference Method 9. If emissions which appear to be in excess of the permitted level are observed, the permittee shall take immediate action to identify and correct the cause of the visible emissions. After corrective action has been taken, which may include shutting down and restarting the unit, the permittee shall conduct another observation of the opacity from this source. If the opacity observed does not appear to be in excess of the permitted level, then no further action is needed, and the permittee will be considered in compliance with the permitted opacity limit. If visible emissions which appear to be in excess of the permitted level are still observed, a 6-minute visible emissions reading shall be conducted by a person certified in EPA Reference Method 9 to determine if the opacity is less than the permitted level. If the opacity observed is not in excess of the permitted level, then no further action is needed, and the permittee will be considered in compliance with the permitted opacity limit and §19.705 of Regulation 19. If no Method 9 reading is conducted despite emissions appearing to be in excess of the permitted level after corrective action has been taken, the permittee shall be considered out of compliance with the permitted opacity limit and §19.705 of Regulation 19 for that day. The permittee shall maintain records which contain the following items in order to demonstrate

compliance with this specific condition. These records shall be updated daily, kept on site, and made available to Department personnel upon request and shall include:

a. The date and time of the observation;
b. If visible emissions which appeared to be above the permitted limit were detected;
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken; and
d. The name of the person conducting the opacity observations. For observations made on weekends or holidays, the report may be prepared by a member of the environmental compliance staff who may not have actually observed the emissions. This report will be based upon an interview with the person who actually observed the emissions conducted by a member of the environmental compliance staff who is certified in EPA Reference Method 9. This report must be completed on or before the next business day.

[Regulation 18, §18.1004, Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52 Subpart E]

11. The permittee shall comply with requirements found in the Existing Units Operating Scenario up to the period for which the source(s) no longer have any applicable requirements under the Existing Units Operating Scenario. The permittee shall comply with the applicable requirements for each source(s) under Expansion Project Operating Scenario as they become applicable. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Title VI Provisions

12. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

13. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)
e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

14. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

15. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

16. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated October 1, 2009.

Description	Category
Molten Sulfur Storage Tank (formerly SN-23)	B-21
Diesel Storage Tank (500 Gallon) (formerly SN-24)	A-3
Diesel Storage Tank (500 Gallon) (formerly SN-36)	A-3
Diesel Storage Tank (2,000 Gallon) (formerly SN-45)	A-3
Diesel Storage Tank (2,000 Gallon)	A-3
2 x Ammonia Flares	A-13
Air Liquide Cooling Tower	A-13
Sulfur Unloading/Storage	A-13
Ammonia Offloading	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and Regulation 26 §26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26 §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26 §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

   g. The date, place as defined in this permit, and time of sampling or measurements;
   h. The date(s) analyses performed;
   i. The company or entity performing the analyses;
   j. The analytical techniques or methods used;
   k. The results of such analyses; and
   l. The operating conditions existing at the time of sampling or measurement.

   [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26 §26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26 §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 CFR 70.6(a)(3)(iii)(A) and Regulation 26 §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      x. The facility name and location;
      xi. The process unit or emission source deviating from the permit limit;
      xii. The permit limit, including the identification of pollutants, from which deviation occurs;
      xiii. The date and time the deviation started;
      xiv. The duration of the deviation;
      xv. The average emissions during the deviation;
      xvi. The probable cause of such deviations;
      xvii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
      xviii. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19 §19.601 and §19.602, Regulation 26 §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26 §26.701(E), and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26 §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26 §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26 §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26 §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26 §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26 §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26 §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26 §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26 §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26 §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26 §26.703(B)]

    e. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    f. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    g. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

h. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26 §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26 §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

d. Such an extension does not violate a federal requirement;
e. The permittee demonstrates the need for the extension; and

f. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18 §18.314(A), Regulation 19 §19.416(A), Regulation 26 §26.1013(A), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

g. Such a request does not violate a federal requirement;
h. Such a request is temporary in nature;
i. Such a request will not result in a condition of air pollution;
j. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
k. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
l. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18 §18.314(B), Regulation 19 §19.416(B), Regulation 26 §26.1013(B), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

a. The request does not violate a federal requirement;
b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18 §18.314(C), Regulation 19 §19.416(C), Regulation 26 §26.1013(C), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

APPENDIX A

40 CFR Part 60, Subpart Db - *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Contents

SOURCE: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_x) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_x standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_x standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the NO_x standards under this subpart and the PM and SO_2 standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO_x and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; § 60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under § 60.281 is not considered a modification under § 60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, § 60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_x standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.* , steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (or 1.2 lb/MMBtu);

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

H_b = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

H_d = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in § 60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under § 60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28,

2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.44b Standard for nitrogen oxides (NO_x).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO_2) in excess of the following emission limits:

	Nitrogen oxide emission limits (expressed as NO_2) heat input	
Fuel/steam generating unit type	**ng/J**	**lb/MMBTu**
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_x emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_x emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_x emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_x emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_x emission limit will be established at the NO_x emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_x emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_x emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_x emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_x emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_x emission limits of this section. The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_x standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_x emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_x emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.48Da(i) of subpart Da of this part, and must monitor emissions according to § 60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards in § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of § 60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$ = Potential SO_2 emission rate, percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2 emission rate ($E_{ho}°$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}°$). The Eho° is computed using the following formula:

$$E_{ho}^{o} = \frac{E_{ho} - E_{w}(1 - X_1)}{X_1}$$

Where:

E_{ho}° = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2 emission rate ($\%P_s$), an adjusted $\%R_g$ ($\%R_g^{\circ}$) is computed from the adjusted E_{ao}° from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet rate (E_{ai}°) using the following formula:

$$\%R_g^{\circ} = 100\left(1.0 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

To compute E_{ai}°, an adjusted hourly SO_2 inlet rate (E_{hi}°) is used. The E_{hi}° is computed using the following formula:

$$E_{hi}^{\circ} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

E_{hi}° = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under § 60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§ 60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_x emission standards under § 60.44b apply at all times.

(b) Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_x emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_x required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring NO_x under § 60.48(b).

(1) For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under § 60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_x emission standards in § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_x standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_x standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of § 60.48b(g)(1) apply and the provisions of § 60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_x required by § 60.44b(a)(4) or § 60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of NO_x shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)(E_{sg} - E_g) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_x from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_x concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under § 60.44b(a)(4) or § 60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under § 60.48b for measuring NO_x and O_2 and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_x emission standards under § 60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_x emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs § 60.43b(a)(4) or § 60.43b(h)(5) shall follow the applicable procedures in § 60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily

arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of § 60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of § 60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, E_D , shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_x monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_x monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_x span values less than or equal to 30 ppm; and

(iii) For SO_2 , CO_2 , and O_2 monitoring systems and for NO_x emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_x when the average NO_x emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.46d(d)(7).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_x standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_x and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_x is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_x span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_x span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_x standards in § 60.44b(a)(4), § 60.44b(e), or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a CEMS for measuring NO_x emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under § 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO_2 . The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 , PM, and/or NO_x emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_x standard in § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in § 60.48b(g)(2) and the records to be maintained in § 60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_x emission rates (*i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.* , flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The

annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_x standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_x emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_x emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) Any affected facility that is subject to the NO_x standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_x emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§ 60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§ 60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in § 60.42(b) for which the minimum amount of data required in § 60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) is used to determine the overall percent reduction (*i.e.* , $\%R_o$) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any NO_x emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_x emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted

to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_x standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b(i).

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_x standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_x burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_x technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_x standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific NO_x standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO* $_x$. (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_x emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO* $_x$. (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

APPENDIX B

40 CFR Part 60, Subpart G - *Standards of Performance for Nitric Acid Plants*

Subpart G—Standards of Performance for Nitric Acid Plants

§ 60.70 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

[42 FR 37936, July 25, 1977]

§ 60.71 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Nitric acid production unit* means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

(b) *Weak nitric acid* means acid which is 30 to 70 percent in strength.

§ 60.72 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid.

(2) Exhibit 10 percent opacity, or greater.

[39 FR 20794, June 14, 1974, as amended at 40 FR 46258, Oct. 6, 1975]

§ 60.73 Emission monitoring.

(a) The source owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides (NO_X). The pollutant gas mixtures under Performance Specification 2 and for calibration checks under §60.13(d) of this part shall be nitrogen dioxide (NO_2). The span value shall be 500 ppm of NO_2. Method 7 shall be used for the performance evaluations under §60.13(c). Acceptable alternative methods to Method 7 are given in §60.74(c).

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton). The conversion factor shall be established by measuring emissions with the continuous monitoring system concurrent with measuring emissions with the applicable reference method tests. Using only that portion of the continuous monitoring emission data that represents emission measurements concurrent with the reference method test periods, the conversion factor shall be determined by dividing the reference method test data averages by the monitoring data averages to obtain a ratio expressed in units of the applicable standard to units of the monitoring data, i.e., kg/metric ton per ppm (lb/ton per ppm). The conversion factor shall be reestablished during any performance test under §60.8 or any continuous monitoring system performance evaluation under §60.13(c).

(c) The owner or operator shall record the daily production rate and hours of operation.

(d) [Reserved]

(e) For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as any 3-hour period during which the average nitrogen oxides emissions (arithmetic average of three contiguous 1-hour periods) as measured by a continuous monitoring system exceed the standard under §60.72(a).

[39 FR 20794, June 14, 1974, as amended at 40 FR 46258, Oct. 6, 1975; 50 FR 15894, Apr. 22, 1985; 54 FR 6666, Feb. 14, 1989]

§ 60.74 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the NO_Xstandard in §60.72 as follows:

(1) The emission rate (E) of NO_Xshall be computed for each run using the following equation:

$E=(C_sQ_{sd})/(P\ K)$

where:

E=emission rate of NO_Xas NO_2, kg/metric ton (lb/ton) of 100 percent nitric acid.

C_s=concentration of NO_Xas NO_2, g/dscm (lb/dscf).

Q_{sd}=volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

P=acid production rate, metric ton/hr (ton/hr) or 100 percent nitric acid.

K=conversion factor, 1000 g/kg (1.0 lb/lb).

(2) Method 7 shall be used to determine the NO_Xconcentration of each grab sample. Method 1 shall be used to select the sampling site, and the sampling point shall be the centroid of the stack or duct or at a point no closer to the walls than 1 m (3.28 ft). Four grab samples shall be taken at approximately 15-minute intervals. The arithmetic mean of the four sample concentrations shall constitute the run value (C_s).

(3) Method 2 shall be used to determine the volumetric flow rate (Q_{sd}) of the effluent gas. The measurement site shall be the same as for the NO_Xsample. A velocity traverse shall be made once per run within the hour that the NO_Xsamples are taken.

(4) The methods of §60.73(c) shall be used to determine the production rate (P) of 100 percent nitric acid for each run. Material balance over the production system shall be used to confirm the production rate.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 7, Method 7A, 7B, 7C, or 7D may be used. If Method 7C or 7D is used, the sampling time shall be at least 1 hour.

(d) The owner or operator shall use the procedure in §60.73(b) to determine the conversion factor for converting the monitoring data to the units of the standard.

[54 FR 6666, Feb. 14, 1989]

APPENDIX C

40 CFR Part 60, Subpart Ga – *Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011*

Subpart Ga—Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011

Contents

SOURCE: 77 FR 48445, Aug. 14, 2012, unless otherwise noted.

§ 60.70a Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) This subpart applies to any nitric acid production unit that commences construction or modification after October 14, 2011.

§ 60.71a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Monitoring system malfunction means a sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to implement monitoring system repairs in response to monitoring system malfunctions or out-of-control periods, and to return the monitoring system to operation as expeditiously as practicable.

Nitric acid production unit means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

Operating day means a 24-hour period beginning at 12:00 a.m. during which the nitric acid production unit operated at any time during this period.

Weak nitric acid means acid which is 30 to 70 percent in strength.

§ 60.72a Standards.

Nitrogen oxides. On and after the date on which the performance test required to be conducted by § 60.73a(e) is completed, you may not discharge into the atmosphere from any affected facility any gases which contain NO_x , expressed as NO_2 , in excess of 0.50 pounds (lb) per ton of nitric acid produced, as a 30-day emission rate calculated based on 30 consecutive operating days, the production being expressed as 100 percent nitric acid. The emission standard applies at all times.

§ 60.73a Emissions testing and monitoring.

(a) *General emissions monitoring requirements.* You must install and operate a NO_x concentration (ppmv) continuous emissions monitoring system (CEMS). You must also install and operate a stack gas flow rate monitoring system. With measurements of stack gas NO_x concentration and stack gas flow rate, you will determine hourly NO_x emissions rate (e.g., lb/hr) and with measured data of the hourly nitric acid production (tons), calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). You must operate the monitoring system and report emissions during all operating periods including unit startup and shutdown, and malfunction.

(b) *Nitrogen oxides concentration continuous emissions monitoring system.* (1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the concentration of NO_x emissions in accordance with the provisions of § 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of this part. You must use cylinder gas audits to fulfill the quarterly auditing requirement at section 5.1 of Procedure 1 of Appendix F of this part for the NO_x concentration CEMS.

(2) For the NO_x concentration CEMS, use a span value, as defined in Performance Specification 2, section 3.11, of Appendix B of this part, of 500 ppmv (as NO_2). If you emit NO_x at concentrations higher than 600 ppmv (e.g., during startup or shutdown periods), you must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NO_x emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods.

(3) For conducting the relative accuracy test audits, per Performance Specification 2, section 8.4, of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, use either EPA Reference Method 7, 7A, 7C, 7D, or 7E of Appendix A-4 of this part; EPA Reference Method 320 of Appendix A of part 63 of this chapter; or ASTM D6348-03 (incorporated by reference, see § 60.17). To verify the operation of the second CEMS or the higher range of a dual analyzer CEMS described in paragraph (b)(2) of this section, you need not conduct a relative accuracy test audit but only the calibration drift test initially (found in Performance Specification 2, section 8.3.1, of Appendix B of this part) and the cylinder gas audit thereafter (found in Procedure 1, section 5.1.2, of Appendix F of this part).

(4) If you use EPA Reference Method 7E of Appendix A-4 of this part, you must mitigate loss of NO_2 in water according to the requirements in paragraphs (b)(4)(i), (ii), or (iii) of this section and verify performance by conducting the system bias checks required in EPA Reference Method 7E, section 8, of Appendix A-4 of this part according to (b)(4)(iv) of this section, or follow the dynamic spike procedure according to paragraph (b)(4)(v) of this section.

(i) For a wet-basis measurement system, you must measure and report temperature of sample line and components (up to analyzer inlet) to demonstrate that the temperatures remain above the sample gas dew point at all times during the sampling.

(ii) You may use a dilution probe to reduce the dew point of the sample gas.

(iii) You may use a refrigerated-type condenser or similar device (e.g., permeation dryer) to remove condensate continuously from sample gas while maintaining minimal contact between condensate and sample gas.

(iv) If your analyzer measures nitric oxide (NO) and nitrogen dioxide (NO_2) separately, you must use both NO and NO_2 calibration gases. Otherwise, you must substitute NO_2 calibration gas for NO calibration gas in the performance of system bias checks.

(v) You must conduct dynamic spiking according to EPA Reference Method 7E, section 16.1, of Appendix A-4 of this part using NO_2 as the spike gas.

(5) Instead of a NO_x concentration CEMS meeting Performance Specification 2, you may apply an FTIR CEMS meeting the requirements of Performance Specification 15 of Appendix B of this part to measure NO_x concentrations. Should you use an FTIR CEMS, you must replace the Relative Accuracy Test Audit requirements of Procedure 1 of appendix F of this part with the validation requirements and criteria of Performance Specification 15, sections 11.1.1 and 12.0, of Appendix B of this part.

(c) *Determining NO_x mass emissions rate values.* You must use the NO_x concentration CEMS, acid production, gas flow rate monitor and other monitoring data to calculate emissions data in units of the applicable limit (lb NO_x /ton of acid produced expressed as 100 percent nitric acid).

(1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the stack gas flow rates to use in combination with data from the CEMS for measuring emissions concentrations of NO_x to produce data in units of mass rate (e.g., lb/hr) of NO_x on an hourly basis. You will operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of § 60.13 and Performance Specification 6 of Appendix B of this part. You must comply with the following provisions in (c)(1)(i) through (iii) of this section.

(i) You must use a stack gas flow rate sensor with a full scale output of at least 125 percent of the maximum expected exhaust volumetric flow rate (see Performance Specification 6, section 8, of Appendix B of this part).

(ii) For conducting the relative accuracy test audits, per Performance Specification 6, section 8.2 of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, you must use either EPA Reference Method 2, 2F, or 2G of Appendix A-4 of this part. You may also apply Method 2H in conjunction with other velocity measurements.

(iii) You must verify that the CERMS complies with the quality assurance requirements in Procedure 1 of Appendix F of this part. You must conduct relative accuracy testing to provide for calculating the relative accuracy for RATA and RAA determinations in units of lb/hour.

(2) You must determine the nitric acid production parameters (production rate and concentration) by installing, calibrating, maintaining, and operating a permanent monitoring system (e.g., weigh scale, volume flow meter, mass flow meter, tank volume) to measure and record the weight rates of nitric acid produced in tons per hour. If your nitric acid production rate measurements are for periods longer than hourly (e.g., daily values), you will determine average hourly production values, tons acid/hr, by dividing the total acid production by the number of hours of process operation for the subject measurement period. You must comply with the following provisions in (c)(2)(i) through (iv) of this section.

(i) You must verify that each component of the monitoring system has an accuracy and precision of no more than ±5 percent of full scale.

(ii) You must analyze product concentration via titration or by determining the temperature and specific gravity of the nitric acid. You may also use ASTM E1584-11 (incorporated by reference, see § 60.17), for determining the concentration of nitric acid in percent. You must determine product concentration daily.

(iii) You must use the acid concentration to express the nitric acid production as 100 percent nitric acid.

(iv) You must record the nitric acid production, expressed as 100 percent nitric acid, and the hours of operation.

(3) You must calculate hourly NO_x emissions rates in units of the standard (lb/ton acid) for each hour of process operation. For process operating periods for which there is little or no acid production (e.g., startup or shutdown), you must use the average hourly acid production rate determined from the data collected over the previous 30 days of normal acid production periods (see § 60.75a).

(d) *Continuous monitoring system.* For each continuous monitoring system, including NO_x concentration measurement, volumetric flow rate measurement, and nitric acid production measurement equipment, you must meet the requirements in paragraphs (d)(1) through (3) of this section.

(1) You must operate the monitoring system and collect data at all required intervals at all times the affected facility is operating except for periods of monitoring system malfunctions or out-of-control periods as defined in Appendix F, sections 4 and 5, of this part, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.

(2) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in calculating emissions and the status of compliance with the applicable emissions limit in accordance with § 60.72a(a).

(e) *Initial performance testing.* You must conduct an initial performance test to demonstrate compliance with the NO_x emissions limit under § 60.72a(a) beginning in the calendar month following initial certification of the NO_x and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NO_x average concentration, mass flow rate recorded with the certified NO_x concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. You must assure that the CERMS meets all of the data quality assurance requirements as per § 60.13 and Appendix F, Procedure 1, of this part and you must use the data from the CERMS for this compliance determination.

§ 60.74a Affirmative defense for violations of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 60.72a, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

§ 60.75a Calculations.

(a) You must calculate the 30 operating day rolling arithmetic average emissions rate in units of the applicable emissions standard (lb NO_x /ton 100 percent acid produced) at the end of each operating day using all of the quality assured hourly average CEMS data for the previous 30 operating days.

(b) You must calculate the 30 operating day average emissions rate according to Equation 1:

$$E_{30} = \frac{k \frac{1}{n} \sum_{i=1}^{n} C_i Q_i}{P_i} \quad \text{(Eq. 1)}$$

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Where:

E_{30} = 30 operating day average emissions rate of NO_x , lb NO_x /ton of 100 percent HNO_3 ;

C_i = concentration of NO_x for hour i, ppmv;

Q_i = volumetric flow rate of effluent gas for hour i, where C_i and Q_i are on the same basis (either wet or dry), scf/hr;

P_i = total acid produced during production hour i, tons 100 percent HNO_3 ;

k = conversion factor, 1.194×10^{-7} for NO_x ; and

n = number of operating hours in the 30 operating day period, i.e., n is between 30 and 720.

§ 60.76a Recordkeeping.

(a) For the NO_x emissions rate, you must keep records for and results of the performance evaluations of the continuous emissions monitoring systems.

(b) You must maintain records of the following information for each 30 operating day period:

(1) Hours of operation.

(2) Production rate of nitric acid, expressed as 100 percent nitric acid.

(3) 30 operating day average NO_x emissions rate values.

(c) You must maintain records of the following time periods:

(1) Times when you were not in compliance with the emissions standards.

(2) Times when the pollutant concentration exceeded full span of the NO_x monitoring equipment.

(3) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must maintain records of the reasons for any periods of noncompliance and description of corrective actions taken.

(e) You must maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications.

(f) For each malfunction, you must maintain records of the following information:

(1) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

§ 60.77a Reporting.

(a) The performance test data from the initial and subsequent performance tests and from the performance evaluations of the continuous monitors must be submitted to the Administrator at the appropriate address as shown in 40 CFR 60.4.

(b) The following information must be reported to the Administrator for each 30 operating day period where you were not in compliance with the emissions standard:

(1) Time period;

(2) NO_x emission rates (lb/ton of acid produced);

(3) Reasons for noncompliance with the emissions standard; and

(4) Description of corrective actions taken.

(c) You must also report the following whenever they occur:

(1) Times when the pollutant concentration exceeded full span of the NO_x pollutant monitoring equipment.

(2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications.

(e) Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, you must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/SSL/cdx/EPA_Home.asp*). You must submit performance test data in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods listed on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. Mark the compact disk or other commonly used electronic storage media clearly as CBI and mail to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, you must also submit these reports to the delegated authority in the format specified by the delegated authority. You must submit the other information as required in the performance evaluation as described in § 60.2 and as required in this chapter.

(f) If a malfunction occurred during the reporting period, you must submit a report that contains the following:

(1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

(2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with § 60.11(d), including actions taken to correct a malfunction.

APPENDIX D

40 CFR Part 60, Subpart H – *Standards of Performance for Sulfuric Acid Plants*

Subpart H—Standards of Performance for Sulfuric Acid Plants

§ 60.80 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each sulfuric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

[42 FR 37936, July 25, 1977]

§ 60.81 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Sulfuric acid production unit* means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(b) *Acid mist* means sulfuric acid mist, as measured by Method 8 of appendix A to this part or an equivalent or alternative method.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 20794, June 14, 1974]

§ 60.82 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4.

[39 FR 20794, June 14, 1974]

§ 60.83 Standard for acid mist.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H_2SO_4.

(2) Exhibit 10 percent opacity, or greater.

[39 FR 20794, June 14, 1974, as amended at 40 FR 46258, Oct. 6, 1975]

§ 60.84 Emission monitoring.

(a) A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under Performance Specification 2 and for calibration checks under §60.13(d), shall be sulfur dioxide (SO_2). Method 8 shall be used for conducting monitoring system performance evaluations under §60.13(c) except that only the sulfur dioxide portion of the Method 8 results shall be used. The span value shall be set at 1000 ppm of sulfur dioxide.

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999–AP–13) and calculating the appropriate conversion factor for each eight-hour period as follows:

$$CF=k[(1.000-0.015r)/(r-s)]$$

where:

CF=conversion factor (kg/metric ton per ppm, lb/ton per ppm).

k=constant derived from material balance. For determining CF in metric units, k=0.0653. For determining CF in English units, k=0.1306.

r=percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Administrator's approval.

s=percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under paragraph (a) of this section.

(c) The owner or operator shall record all conversion factors and values under paragraph (b) of this section from which they were computed (i.e., CF, r, and s).

(d) Alternatively, a source that processes elemental sulfur or an ore that contains elemental sulfur and uses air to supply oxygen may use the following continuous emission monitoring approach and calculation procedures in determining SO_2emission rates in terms of the standard. This procedure is not required, but is an alternative that would alleviate problems encountered in the measurement of gas velocities or production rate. Continuous emission monitoring systems for measuring SO_2, O_2, and CO_2(if required) shall be installed, calibrated, maintained, and operated by the owner or operator and subjected to the certification procedures in Performance Specifications 2 and 3. The calibration procedure and span value for the SO_2monitor shall be as specified in paragraph (b) of this section. The span value for CO_2(if required) shall be 10 percent and for O_2shall be 20.9 percent (air). A conversion factor based on process rate data is not necessary. Calculate the SO_2emission rate as follows:

$$E_s=(C_sS)/[0.265-(0.126\ \%O_2)-(A\ \%CO_2)]$$

where:

E_s=emission rate of SO_2, kg/metric ton (lb/ton) of 100 percent of H_2SO_4produced.

C_s=concentration of SO_2, kg/dscm (lb/dscf).

S=acid production rate factor, 368 dscm/metric ton (11,800 dscf/ton) of 100 percent H_2SO_4produced.

$\%O_2$=oxygen concentration, percent dry basis.

A=auxiliary fuel factor,

=0.00 for no fuel.

=0.0226 for methane.

=0.0217 for natural gas.

=0.0196 for propane.

=0.0172 for No 2 oil.

=0.0161 for No 6 oil.

=0.0148 for coal.

=0.0126 for coke.

$\%CO_2$= carbon dioxide concentration, percent dry basis.

Note: It is necessary in some cases to convert measured concentration units to other units for these calculations:

Use the following table for such conversions:

From—	To—	Multiply by—
g/scm	kg/scm	10^{-3}
mg/scm	kg/scm	10^{-6}
ppm (SO_2)	kg/scm	2.660×10^{-6}
ppm (SO_2)	lb/scf	1.660×10^{-7}

(e) For the purpose of reports under §60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under §60.82.

[39 FR 20794, June 14, 1974, as amended at 40 FR 46258, Oct. 6, 1975; 48 FR 23611, May 25, 1983; 48 FR 4700, Sept. 29, 1983; 48 FR 48669, Oct. 20, 1983; 54 FR 6666, Feb. 14, 1989; 65 FR 61753, Oct. 17, 2000]

§ 60.85 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the SO_2acid mist, and visible emission standards in §§60.82 and 60.83 as follows:

(1) The emission rate (E) of acid mist or SO_2shall be computed for each run using the following equation:

$E=(CQ_{sd})/(PK)$

where:

E=emission rate of acid mist or SO_2kg/metric ton (lb/ton) of 100 percent H_2SO_4produced.

C=concentration of acid mist or SO_2, g/dscm (lb/dscf).

Q_{sd}=volumetric flow rate of the effluent gas, dscm/hr (dscf/hr).

P=production rate of 100 percent H_2SO_4, metric ton/hr (ton/hr).

K=conversion factor, 1000 g/kg (1.0 lb/lb).

(2) Method 8 shall be used to determine the acid mist and SO_2concentrations (C's) and the volumetric flow rate (Q_{sd}) of the effluent gas. The moisture content may be considered to be zero. The sampling time and sample volume for each run shall be at least 60 minutes and 1.15 dscm (40.6 dscf).

(3) Suitable methods shall be used to determine the production rate (P) of 100 percent $H_2SO_4$for each run. Material balance over the production system shall be used to confirm the production rate.

(4) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) If a source processes elemental sulfur or an ore that contains elemental sulfur and uses air to supply oxygen, the following procedure may be used instead of determining the volumetric flow rate and production rate:

(i) The integrated technique of Method 3 is used to determine the O_2concentration and, if required, CO_2concentration.

(ii) The SO_2or acid mist emission rate is calculated as described in §60.84(d), substituting the acid mist concentration for $C_s$as appropriate.

[54 FR 6666, Feb. 14, 1989]

APPENDIX E

40 CFR Part 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

$\%CO_2$= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101–549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63.6640(f). All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst

NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the

	and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]

2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	Comply with any operating limitations approved by the Administrator.

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	

	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI	a. Change oil and filter every 1,440 hours of	

RICE <100 HP that are not 2SLB stationary RICE	operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or	

stationary RICE 100≤HP≤500	less at 15 percent O_2	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	

2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours	

	of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	

9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[75 FR 51595, Aug. 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE		

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug. 20, 2010]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2at the inlet and outlet of the control device; and	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[a](incorporated by reference, see §63.14). Measurements to determine O_2must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[ab](incorporated by reference, see §63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. Reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde

				concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	(a) Measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis.

		stationary RICE; or	D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b]You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if. . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and

emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the

operated more than 24 hours per calendar year		Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.

7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved

		operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde

source of HAP		or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating

		limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and

		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to

		§63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4) i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the	

		requirements in §63.6650(b).	
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.	
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.	
		c. Any problems or errors suspected with the meters. i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	

§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.

§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	

§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance	Yes	Except that §63.9(c) only

	extension		applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	

§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)–(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	

§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

APPENDIX F

40 CFR Part 63, Subpart DDDDD - *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Contents

SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7491 was amended by revising paragraph (n). However, there is no paragraph (n) to revise.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7495 was amended by adding paragraph (e). However, there is already a paragraph (e).

Emission Limitations and Work Practice Standards

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7163, Jan. 31, 2013]

General Compliance Requirements

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013]

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

[78 FR 7164, Jan. 31, 2013]

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013]

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013]

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad (Eq.\ 1a)$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times So) \div \sum_{i=1}^{n} So \qquad (Eq.\ 1b)$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad (Eq.\ 1c)$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Sm \times Cfi) \div \sum_{i=1}^{n}(Sm \times Cfi) \quad \text{(Eq. 2)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Hb) \div \sum_{i=1}^{n} Hb \quad \text{(Eq. 3a)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \quad \text{(Eq. 3b)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \quad \text{(Eq. 3c)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategories, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 5)}$$

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Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013]

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of

control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.* , PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.* , check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013]

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n}(Ci \times Qi) \quad \text{(Eq. 7)}$$

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Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

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Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \quad \text{(Eq. 9)}$$

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Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{X} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{Y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

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Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

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Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

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Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \qquad \text{(Eq. 13)}$$

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Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30\text{-day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

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Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers ("back half") of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the "back half" for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run. (iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

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Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \quad \text{(Eq. 16)}$$

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Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \quad \text{(Eq. 17)}$$

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Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} (TSM90i \times Qi) \qquad \text{(Eq. 18)}$$

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Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013]

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html* .

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual}\right) \div EI_{baseline} \quad \text{(Eq. 19)}$$

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Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

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Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013]

Continuous Compliance Requirements

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013]

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to

initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013]

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to § 63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013]

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the

reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

[78 FR 7183, Jan. 31, 2013]

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep

records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013]

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 7186, Jan. 31, 2013]

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented

by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or 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 due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{CBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 21)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{CBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 22)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{CBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 23)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{CBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 24)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$$EL_{CBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$$

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Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 [a]lb per MMBtu of heat input	8.7E-07 [a]lb per MMBtu of steam output or 1.1E-05 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

		oxygen, 30-day rolling average)		
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.

		oxygen, 30-day rolling average)		
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 [a]lb per MMBtu of steam output or 1.2E-03 [a]lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 [a]lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.

13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	5.3E-07 [a]lb per MMBtu of steam output or 6.7E-06 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 [a]lb per MMBtu of steam output or 1.6E-02 [a]lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.

17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[78 FR 7193, Jan. 31, 2013]

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units	a. CO (or	130 ppm by volume on a	0.12 lb per MMBtu of	1 hr minimum sampling

designed to burn coal/solid fossil fuel	CEMS)	dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	steam output or 1.4 lb per MWh; 3-run average	time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb	1.4E-01 lb per MMBtu of steam	Collect a minimum of 1 dscm per run.

	TSM)	per MMBtu of heat input)	output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average	1 hr minimum sampling time.

		corrected to 3 percent oxygen, 30-day rolling average)		
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b]collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7195, Jan. 31, 2013]

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for

	improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
	If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.
	You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports

	concerning activities and periods of shutdown, as specified in § 63.7555.

[78 FR 7198, Jan. 31, 2013]

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates

	calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2CEMS, maintain the 30-day rolling average SO_2emission rate at or below the highest hourly average SO_2concentration measured during the most recent HCl performance test, as specified in Table 8.

[78 FR 7199, Jan. 31, 2013]

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant...	You must...	Using...
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.

2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]

	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013]

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323 [a](for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 [a](for liquid), or ASTM D4057 [a](for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a](for biomass), or EPA 3050 [a](for solid fuel), or EPA 821-R-01-013 [a](for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM

		D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864 [a], or ASTM D240, or ASTM D95 [a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a](for coal), EPA SW-846-7471B [a](for solid samples), or EPA SW-846-7470A [a](for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M§[a](for coal), or ASTM D5198§[a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), ASTM D5864, ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864 [a], or ASTM D240 [a], or ASTM D95[a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 [a], ASTM D6721 [a], ASTM D4208 [a](for coal), or EPA SW-846-5050 [a]or ASTM E776 [a](for solid fuel), or EPA SW-846-9056 [a]or SW-846-9076 [a](for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954 [a], ASTM D6350 [a], ISO 6978-1:2003(E) [a], or ISO 6978-2:2003(E) [a], or EPA-1631 [a]or equivalent.

	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 [a]or equivalent.
4. TSM for solid fuels	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), or ASTM D4177 [a],(for liquid fuels)or ASTM D4057 [a](for liquid fuels),or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a]or TAPPI T266 [a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864, or ASTM D240 [a], or ASTM D95 [a](for liquid fuels), or ASTM D4006[a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683 [a], or ASTM D4606 [a], or ASTM D6357 [a]or EPA 200.8 [a]or EPA SW-846-6020 [a], or EPA SW-846-6020A [a], or EPA SW-846-6010C [a], EPA 7060 [a]or EPA 7060A [a](for arsenic only), or EPA SW-846-7740 [a](for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

[78 FR 7201, Jan. 31, 2013]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements

1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests.
				(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b)	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.

		used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent		
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2emission rate	i. Establish a site-specific maximum SO_2emission rate operating limit according to § 63.7530(b)	(1) Data from SO_2CEMS and the HCl performance test	(a) You must collect the SO_2emissions data according to § 63.7525(m) during the most recent HCl performance tests.
				(b) The maximum SO_2emission rate is equal to the lowest hourly average SO_2emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest

				hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7203, Jan. 31, 2013]

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and

	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes.
	b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2emissions using SO_2CEMS	a. Collecting the SO_2CEMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2CEMS emission rate to a level at or below the minimum hourly SO_2rate measured during the most recent HCl performance test according to § 63.7530.

[78 FR 7204, Jan. 31, 2013]

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a	

	statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and	No.

	malfunction plan requirements.	
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.

§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.

§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

Dioxin/furan congener	**Toxic equivalency factor**
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003

2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

[76 FR 15664, Mar. 21, 2011]

EDITORIAL NOTE: At 78 FR 7206, Jan. 31, 2013, Table 11 was added, effective Apr. 1, 2013. However Table 11 could not be added as a Table 11 is already in existence.

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel	a. Mercury	3.5E-06 lb per MMBtu of heat input	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.

3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
7. Stokers designed to burn biomass/bio-based solids	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent	Collect a minimum of 4 dscm per run.

		oxygen	
10. Fuel cells designed to burn biomass/bio-based solids	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	3.0E-07 lb per MMBtu of heat input	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
13. Units designed to burn liquid fuel located in non-continental States and territories	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per

			run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
14. Units designed to burn gas 2 (other) gases	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

[76 FR 15664, Mar. 21, 2011]

EDITORIAL NOTE: At 78 FR 7208, Jan. 31, 2013, Table 12 was added, effective Apr. 1, 2013. However, Table 12 could not be added as a Table 12 is already in existence.

Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before January 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to	1 hr minimum sampling time.

		3 percent oxygen, 30-day rolling average)	
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130 [a]ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average)	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7210, Jan. 31, 2013]

APPENDIX G

Compliance Assurance Monitoring (CAM) Plans

Compliance Assurance Monitoring Applicability Determination

Background

Upon renewal of a Title V permit, a facility must include Compliance Assurance Monitoring (CAM) Plans for certain pollutant-specific emissions units. The following criteria determine the applicability of the CAM Rule (found in 40 CFR Part 64) to emissions units:

1. The pollutant-specific emissions unit must be located at major source with a Title V permit.
2. The unit must be subject to an emission limitation or standard for the applicable regulated air pollutant.
3. The unit uses a control device to achieve compliance with any such emission limitation or standard.
4. The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100% of the major source threshold.

The intent of the CAM Rule is to ensure that facilities maintain control equipment at levels that assure compliance with emission limitations. CAM Plans are the program by which these control devices will be maintained. The elements of a CAM plan must include a description of the indicators to be monitored, the indicator ranges or the process to set indicator ranges, and the performance criteria for the monitoring. These criteria include specifications for obtaining representative data, verification procedures to confirm the operational status of the chosen monitoring, quality assurance and control procedures, monitoring frequency, and the data averaging period. In addition, the plan must contain a justification for the use of parameters/indicators chosen for monitoring, the ranges developed, and the monitoring approach. Finally, an implementation plan for installing, testing, and operating the monitoring must be included.

The CAM Rule requires the following monitoring frequency:

1. Continuous monitoring for units that are classified as a major source after control. For each parameter monitored, the owner or operator shall collect four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging period.
2. Daily monitoring (or some frequency less than continuous but at least once per a 24-hour period) for units that are not classified as a major source after control.

Compliance Assurance Monitoring Applicability Determination

CAM Rule Applicability

The following table outlines the pre-control emission calculations based on the manufacturer's data. As shown below, a CAM Plan is required for each source.

Source No.	Source Description	Pollutant	Pre-Control PTE (tpy)	Control Efficiency (%)	Post Control PTE (tpy)	Type of Monitoring Required
SN-05	E2 Plant Brinks Scrubber	PM_{10}	>100	95.0	10.8	Daily
SN-41	E2 Plant Chemical Steam Scrubber	PM_{10}	>100	Unknown	14.5	Daily
SN-35	Magnesium Oxide Baghouse	PM_{10}	>100	99.0	0.3	Daily
SN-07	Sulfuric Acid Plant	SO_2	>100	see Note 1	401.5	Continuous
SN-08	West Nitric Acid Plant	NO_x	>100	98.5	228.6	Continuous
SN-09	East Nitric Acid Plant	NO_x	>100	98.5	228.6	Continuous
SN-10	Nitric Acid Vent Collection System	NO_x	>100	95.0	85.0	Daily
SN-13	DM Weatherly Nitric Acid Plant No. 1	NO_x	>100	95.0	42.0	Continuous
SN-59	DM Weatherly Nitric Acid Plant No. 2	NO_x	>100	95.0	115.4	Continuous
SN-44	Mixed Acid Plant Scrubber	H_2SO_4 mist SO_3	>100 >100	99.5 99.5	0.18 0.18	Daily
SN-14	KT Plant Brinks Scrubber	PM_{10}	>100	95.0	4.9	Daily
SN-15	KT Plant Dryer / Cooler	PM_{10}	>100	99.9	3.2	Daily
SN-18	KT Plant Clay Baghouse	PM_{10}	>100	99.0	1.9	Daily
SN-21	KT Brinks Scrubber	PM_{10}	>100	99.0	1.5	Daily
SN-63	Ammonium Nitrate Steam Scrubber	PM_{10}	>100	Unknown	14.8	Daily
SN-49	Ammonia Plant Primary Reformer	NO_x	>100	95.0	43.3	Daily

Note:
[1]For SN-07, an absorption tower is considered a control/production device per BACT clearinghouse. Data on how efficient the absorption tower is for controlling SO_2 emissions is not available.

Compliance Assurance Monitoring

E2 Plant Brinks Scrubber

I. E2 Plant Brinks Scrubber Background

A. Emissions Unit

Description:	E2 Plant Brinks Scrubber (2 scrubbers)
Identification:	SN-05
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter:	2.5 lb/hr
Opacity:	20%
Monitoring Requirements:	Scrubber liquid pH, flow rate, gas pressure drop

C. Control Technology: Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

1. Scrubber liquid pH
2. Minimum scrubber liquid flow rate for each scrubber
3. Minimum gas pressure drop for each scrubber

B. Measurement Approach

The scrubber liquid pH, flow rate and the gas pressure drop will be measured and recorded daily.

C. Indicator Range

1. Scrubber liquid range of 0.5 – 6.0
2. The minimum scrubber liquor flow rate is 225 gal/min for each scrubber.
3. The minimum gas pressure drop is 2.5" H_2O for each scrubber.

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Calibration of the monitoring devices (flow meter and pressure drop indices) will be performed once per year.
Monitoring Frequency and Data:	The scrubber liquid pH, flow rate and the gas pressure drop will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A scrubber is used to control some of the particulate matter emissions generated in the E2 Plant. The scrubber has a maximum gas flow rate of 187,152 ft^3/min.

B. Rationale for Selection of Performance Indicator

The scrubber liquid pH, flow rate and gas pressure drop were selected as the performance indicators because they are indicative of operation of the scrubber in a manner necessary to comply with the particulate emission standard. The scrubber liquor flow rate indicates that there is adequate liquor flow to ensure sufficient liquid to gas contact to scrub particulate from the gas prior to it being exhausted to the atmosphere. Monitoring the pH of the scrubber liquid indicates if the scrubber liquid is performing sufficiently. Likewise, the gas pressure drop indicates that there is sufficient air flow to support gas to liquid contact to scrub particulate from the gas prior to it being exhausted to the atmosphere. The minimum scrubber liquor flow rate, the scrubber liquid pH, and the minimum gas pressure drop is monitored to ensure that the scrubber is operating properly. When the scrubber is operating properly, the particulate emissions from the exhaust of the E2 Plant Brinks Scrubber will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameters were selected based on vender recommendations, as influenced by site specific design considerations. Subsequent stack testing has confirmed that the indicator levels are appropriate. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

Compliance Assurance Monitoring

E2 Plant Chemical Steam Scrubber

I. E2 Plant Chemical Steam Scrubber Background

A. Emissions Unit

Description:	E2 Plant Chemical Steam Scrubber
Identification:	SN-41
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter:	13.7 lb/hr (24-hour average) 3.3 lb/hr (30-day average)
Opacity:	15%
Monitoring Requirements:	Continuous sampling of stack gas to produce two 12-hour composite samples per day

C. Control Technology: Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

PM hourly emissions

B. Measurement Approach

Stack sampling will be conducted continuously to produce two 12-hour composite samples each day. Each 12-hour composite sample is analyzed to measure the ammonia and nitrate concentrations. Data from the analyses is then used calculate the mass concentration of condensable particulate matter and produce a lb/day value.

C. Indicator Range

13.7 lb/hr (24-hour average)
3.3 lb/hr (30-day average)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the continuous sampling system.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	QA/QC procedures will be conducted consistent with the required test methods for ammonia and nitrate analyses.
Monitoring Frequency and Data:	Stack sampling will be conducted continuously to produce two 12-hour composite samples each day. Each 12-hour composite sample is analyzed to measure the ammonia and nitrate concentrations. Data from the analyses is then used calculate the mass concentration of condensable particulate matter and produce a lb/day value.
Collection Procedure:	Continuous sampling device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A chemical steam scrubber is used to control the condensable particulate matter emissions generated from the E2 Plant ammonium nitrate neutralizers. The scrubber has a maximum gas flow rate of 64,522 ft^3/min.

B. Rationale for Selection of Performance Indicator

Accurate correlations between PM emissions and monitored operating parameters could not be established; therefore, emissions will be continuously monitored using the required continuous sampling and analysis methodology to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limit; emissions will be continuously monitored using the required continuous sampling and analysis methodology to demonstrate compliance with the permit limits for both averaging periods.

Compliance Assurance Monitoring

Ammonium Nitrate Chemical Steam Scrubber

I. Ammonium Nitrate Chemical Steam Scrubber Background

A. Emissions Unit

Description:	Ammonium Nitrate Chemical Steam Scrubber
Identification:	SN-63
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter:	14.0 lb/hr (24-hour average) 3.4 lb/hr (30-day average)
Opacity:	15%
Monitoring Requirements:	Continuous sampling of stack gas to produce two 12-hour composite samples per day

C. Control Technology: Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

PM hourly emissions

B. Measurement Approach

Stack sampling will be conducted continuously to produce two 12-hour composite samples each day. Each 12-hour composite sample is analyzed to measure the ammonia and nitrate concentrations. Data from the analyses is then used calculate the mass concentration of condensable particulate matter and produce a lb/day value.

C. Indicator Range

14.0 lb/hr (24-hour average)
3.4 lb/hr (30-day average)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the continuous sampling system.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	QA/QC procedures will be conducted consistent with the required test methods for ammonia and nitrate analyses.
Monitoring Frequency and Data:	Stack sampling will be conducted continuously to produce two 12-hour composite samples each day. Each 12-hour composite sample is analyzed to measure the ammonia and nitrate concentrations. Data from the analyses is then used calculate the mass concentration of condensable particulate matter and produce a lb/day value.
Collection Procedure:	Continuous sampling device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A chemical steam scrubber is used to control the condensable particulate matter emissions generated from the E2 Plant ammonium nitrate neutralizers. The scrubber has a maximum gas flow rate of 64,522 ft^3/min.

B. Rationale for Selection of Performance Indicator

Accurate correlations between PM emissions and monitored operating parameters could not be established; therefore, emissions will be continuously monitored using the required continuous sampling and analysis methodology to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limit; emissions will be continuously monitored using the required continuous sampling and analysis methodology to demonstrate compliance with the permit limits for both averaging periods.

Compliance Assurance Monitoring

Magnesium Oxide Baghouse

I. Magnesium Oxide Baghouse

A. Emissions Unit

Description:	Magnesium Oxide Baghouse
Identification:	SN-35
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter (PM):	2.0 lb/hr
Monitoring Requirements:	Gas pressure drop across the baghouse

C. Control Technology

Baghouse

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

Gas pressure drop

B. Measurement Approach

The gas pressure drop across the baghouse will be measured and recorded daily.

C. Indicator Range

0.5" H_2O – 8.0" H_2O

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Preventative maintenance inspection will be performed once per year.
Monitoring Frequency and Data:	The gas pressure drop across the baghouse will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A baghouse is used to control PM emissions generated during magnesium oxide storage and transfer operations.

B. Rationale for Selection of Performance Indicator

The gas pressure drop across the baghouse was selected as the performance indicator because it is indicative of operation of the baghouse in a manner necessary to comply with the PM emission standard. The gas pressure drop across the baghouse indicates the amount of particle build up on the filter media. A freshly cleaned baghouse will have an estimated gas pressure drop of 0.5" H_2O. When the gas pressure drop reaches 8.0" H_2O, the filter media will be cleaned. When the baghouse is operating properly, the PM emissions from the Magnesium Oxide Baghouse will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameter was selected based on vender recommendations, as influenced by site specific design considerations. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

Compliance Assurance Monitoring

Sulfuric Acid Plant

I. Sulfuric Acid Plant Background

A. Emissions Unit

Description:	Sulfuric Acid Plant
Identification:	SN-07
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Sulfur Dioxide:	92.0 lb/hr (3-hr average basis)
	4.0 lb/ton 100% sulfuric acid (3-hr average basis)
Monitoring Requirements:	Sulfur dioxide (SO_2) emissions

C. Control Technology

An absorption tower is considered a control/production device per BACT clearinghouse.

II. Monitoring Approach

A. Indicator

SO_2 hourly emissions

B. Measurement Approach

Continuously monitor SO_2 emissions

C. Indicator Range

4.0 lb/ton 100% sulfuric acid (3-hour average basis)
92.0 lb/hr (3-hour average basis)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the CEMS.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	CEMS is in place and operating, verification is not applicable.

QA/QC Practices and Criteria:	Calibration of the CEMS will be performed in accordance with the QA/QC plan.
Monitoring Frequency and Data:	Continuously monitor SO_2 emissions using a CEMS.
Collection Procedure:	CEMS device

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A control device (an absorption tower) is used to control SO_2 emissions generated in the Sulfuric Acid Plant.

B. Rationale for Selection of Performance Indicator

The post-control SO_2 emissions are above major source thresholds; therefore, emissions will be continuously monitored using a CEMS to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limit. Post-control potential to emit is greater than major source thresholds; therefore, continuous monitoring is conducted to demonstrate compliance.

Compliance Assurance Monitoring

West Nitric Acid Plant

I. West Nitric Acid Plant Background

A. Emissions Unit

Description:	West Nitric Acid Plant
Identification:	SN-08
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Nitrogen Oxide:	52.2 lb/hr
Monitoring Requirements:	Nitrogen oxide (NO_x) emissions

C. Control Technology

Selective Catalytic Reduction (SCR) Unit

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

NO_x hourly emissions

B. Measurement Approach

Continuously monitor NO_x emissions

C. Indicator Range

52.2 lb/hr (3-hour average basis)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the CEMS.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	CEMS is in place and operating, verification is not applicable.
QA/QC Practices and Criteria:	Calibration of the CEMS will be performed in accordance with the QA/QC plan.
Monitoring Frequency and Data:	Continuously monitor NO_x emissions using a CEMS.
Collection Procedure:	CEMS device

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A SCR unit is used to control nitrogen oxide emissions generated in the West Nitric Acid Plant.

B. Rationale for Selection of Performance Indicator

The post-control NO_x emissions are above major source thresholds; therefore, emissions will be continuously monitored using a CEMS to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limit. Post-control potential to emit is greater than major source thresholds; therefore, continuous monitoring is conducted to demonstrate compliance.

Compliance Assurance Monitoring

East Nitric Acid Plant

I. East Nitric Acid Plant Background

A. Emissions Unit

Description:	East Nitric Acid Plant
Identification:	SN-09
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Nitrogen Oxide:	52.2 lb/hr
Monitoring Requirements:	Nitrogen oxide (NO_x) emissions

C. Control Technology

Selective Catalytic Reduction (SCR) Unit

II. Monitoring Approach

A. Indicator

NO_x hourly emissions

B. Measurement Approach

Continuously monitor NO_x emissions

C. Indicator Range

52.2 lb/hr (3-hour average basis)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the CEMS.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	CEMS is in place and operating, verification is not applicable.
QA/QC Practices and Criteria:	Calibration of the CEMS will be performed in accordance with the QA/QC plan.
Monitoring Frequency and Data:	Continuously monitor SO_2 emissions using a CEMS.
Collection Procedure:	CEMS device

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A SCR unit is used to control nitrogen oxide emissions generated in the East Nitric Acid Plant.

B. Rationale for Selection of Performance Indicator

The post-control NO_x emissions are above major source thresholds; therefore, emissions will be continuously monitored using a CEMS to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limit. Post-control potential to emit is greater than major source thresholds; therefore, continuous monitoring is conducted to demonstrate compliance.

Compliance Assurance Monitoring

Nitric Acid Vent Collection System Scrubber

I. Nitric Acid Vent Collection System Scrubber Background

A. Emissions Unit

Description:	Nitric Acid Concentrator Hydrogen Peroxide Scrubber
Identification:	SN-10
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Nitrogen Oxide:	19.4 lb/hr
Monitoring Requirements:	Hydrogen peroxide concentration (%) in the chemical condensate circulated at the scrubber outlet.

C. Control Technology

Hydrogen peroxide scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

Hydrogen peroxide concentration (%) in the chemical condensate.

B. Measurement Approach

Sample, test and record daily the hydrogen peroxide concentration of the chemical condensate.

C. Indicator Range

$> 0\%$

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Lab QA/QC procedures will be followed.
Monitoring Frequency and Data:	The chemical condensate will be sampled and tested daily to determine the hydrogen peroxide concentration.
Collection Procedure:	A sample of the chemical condensate is collected manually and tested for hydrogen peroxide concentration. The test data is recorded manually in the log book.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A scrubber is used to control nitrogen oxide (NO_x) emissions generated by the Nitric Acid Vent Collection System. The scrubber has a maximum gas flow rate of 1,000 ft^3/min.

B. Rationale for Selection of Performance Indicator

The concentration of hydrogen peroxide in the chemical condensate was selected as the performance indicator because it is indicative of operation of the scrubber in a manner necessary to comply with the NO_x emission standard. When the scrubber is operating properly, the NO_x emissions from the exhaust of the Nitric Acid Vent Collection System Scrubber will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameter was selected based on vender recommendations, as influenced by site specific design considerations. Subsequent stack testing has confirmed that the indicator levels are appropriate. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

Compliance Assurance Monitoring

DMW Nitric Acid Plant No. 1

I. DMW Nitric Acid Plant No. 1 Background

A. Emissions Unit

Description:	DMW Nitric Acid Plant No. 1
Identification:	SN-13
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Nitrogen Oxide:	16.7 lb/hr 0.6 lb/ ton 100% nitric acid – 365-day rolling average basis (including SSM related emissions) 1.0 lb/ton 100% nitric acid – 3-hour rolling average basis (excluding SSM related emissions)
Monitoring Requirements:	Nitrogen oxide (NO_x) emissions

C. Control Technology

Refrigerated Absorber
Selective Catalytic Reduction (SCR) Unit

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

NO_x hourly emissions

B. Measurement Approach

Continuously monitor NO_x emissions using dual range CEMS

C. Indicator Range

16.7 lb/hr
0.6 lb/ ton 100% nitric acid – 365-day rolling average basis (including SSM related emissions)
1.0 lb/ton 100% nitric acid – 3-hour rolling average basis (excluding SSM related emissions)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the CEMS.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	CEMS is in place and operating, verification is not applicable.
QA/QC Practices and Criteria:	Calibration of the CEMS will be performed in accordance with the QA/QC plan.
Monitoring Frequency and Data:	Continuously monitor NO_x emissions using a CEMS.
Collection Procedure:	CEMS device

II. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. Control devices (Refrigerated Absorber and SCR Unit) are used to control NO_x emissions generated in the DMW Nitric Acid Plant No. 1.

B. Rationale for Selection of Performance Indicator

NO_x emissions are above major source thresholds after control; therefore, emissions will be continuously monitored using a CEMS to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limits. Post-control potential to emit is greater than major source thresholds; therefore, continuous monitoring is conducted to demonstrate compliance.

DMW Nitric Acid Plant No. 2

I. DMW Nitric Acid Plant No. 2 Background

A. Emissions Unit

Description:	DMW Nitric Acid Plant No. 2
Identification:	SN-59
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R15, Title V Permit
Emission Limits:	

Nitrogen Oxide: 26.4 lb/hr
0.5 lb/ ton 100% nitric acid – 30-day rolling average basis (including SSM related emissions)

Monitoring Requirements: Nitrogen oxide (NO_x) emissions

C. Control Technology

Selective Catalytic Reduction (SCR) Unit

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

NO_x hourly emissions

B. Measurement Approach

Continuously monitor NO_x emissions using dual range CEMS

C. Indicator Range

26.4 lb/hr
0.5 lb/ ton 100% nitric acid – 30-day rolling average basis (including SSM related emissions)

D. QIP Threshold

Excursions will be handled in accordance with the QA/QC Plan for the CEMS.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	CEMS is in place and operating, verification is not applicable.
QA/QC Practices and Criteria:	Calibration of the CEMS will be performed in accordance with the QA/QC plan.
Monitoring Frequency and Data:	Continuously monitor NO_x emissions using a CEMS.
Collection Procedure:	CEMS device

Compliance Assurance Monitoring

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. Control devices (SCR Unit) are used to control NO_x emissions generated in the DMW Nitric Acid Plant No. 2.

B. Rationale for Selection of Performance Indicator

NO_x emissions are above major source thresholds after control; therefore, emissions will be continuously monitored using a CEMS to demonstrate compliance with the permit limits.

C. Rationale for Selection of Indicator Level

The selected indicator is the permit limits. Post-control potential to emit is greater than major source thresholds; therefore, continuous monitoring is conducted to demonstrate compliance.

Mixed Acid Plant Scrubber

I. Mixed Acid Plant Scrubber Background

A. Emissions Unit

Description:	Mixed Acid Plant Scrubber
Identification:	SN-44
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
H_2SO_4 mist:	0.04 lb/hr
SO3:	0.04 lb/hr
Monitoring Requirements:	Scrubber liquid pH, flow rate, gas pressure drop

C. Control Technology: Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

1. Scrubber liquid pH
2. Minimum scrubber liquid flow rate for each scrubber
3. Minimum gas pressure drop for each scrubber

B. Measurement Approach

The scrubber liquid pH, flow rate, and gas pressure drop will be measured and recorded daily.

C. Indicator Range

1. Scrubber liquid range of 0.5 – 7.5
2. The minimum scrubber liquor flow rate is 5.0 gal/min.
3. The minimum gas pressure drop is 10.0" H_2O.

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Calibration of the monitoring devices (flow meter and pressure drop indices) will be performed once per year.
Monitoring Frequency and Data:	The scrubber liquid pH, flow rate, and gas pressure drop will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A scrubber is used to control H_2SO_4 mist and SO_3 emissions generated by Mixed Acid Plant operations. The scrubber has a maximum gas flow rate of 1,000 ft^3/min.

B. Rationale for Selection of Performance Indicator

The scrubber liquid pH, flow rate and gas pressure drop were selected as the performance indicators because they are indicative of operation of the scrubber in a manner necessary to comply with the particulate emission standard. The scrubber liquor flow rate indicates that there is adequate liquor flow to ensure sufficient liquid to gas contact to scrub particulate from the gas prior to it being exhausted to the atmosphere. Monitoring the pH of the scrubber liquid indicates if the scrubber liquid is performing sufficiently. Likewise, the gas pressure drop indicates that there is sufficient air flow to support gas to liquid contact to scrub particulate from the gas prior to it being exhausted to the atmosphere. The minimum scrubber liquor flow rate, the scrubber liquid pH, and the minimum gas pressure drop is monitored to ensure that the scrubber is operating properly. When the scrubber is operating properly, the H_2SO_4 mist and SO_3 emissions from the exhaust of the Mixed Acid Plant Scrubber will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameters were selected based on vender recommendations, as influenced by site specific design considerations. Subsequent stack testing has confirmed that the indicator levels are appropriate. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

KT Plant Brinks Scrubber

I. E2 Plant Brinks Scrubber Background

A. Emissions Unit

Description:	KT Plant Brinks Scrubber
Identification:	SN-14
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter:	1.1 lb/hr
Opacity:	20%
Monitoring Requirements:	Scrubber liquid pH, flow rate, gas pressure drop

C. Control Technology: Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

1. Scrubber liquid pH
2. Minimum scrubber liquid flow rate for each scrubber
3. Minimum gas pressure drop for each scrubber

B. Measurement Approach

The scrubber liquid pH, flow rate and the gas pressure drop will be measured and recorded daily.

C. Indicator Range

1. Scrubber liquid range of 0.5 – 6.0
2. The minimum scrubber liquor flow rate is 225 gal/min for each scrubber.
3. The minimum gas pressure drop is 2.5" H_2O for each scrubber.

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Calibration of the monitoring devices (flow meter and pressure drop indices) will be performed once per year.
Monitoring Frequency and Data:	The scrubber liquid pH, flow rate and the gas pressure drop will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A scrubber is used to control some of the particulate matter emissions generated in the E2 Plant. The scrubber has a maximum gas flow rate of 96,900 ft^3/min.

B. Rationale for Selection of Performance Indicator

The scrubber liquid pH, flow rate and gas pressure drop were selected as the performance indicators because they are indicative of operation of the scrubber in a manner necessary to comply with the particulate emission standard. The scrubber liquor flow rate indicates that there is adequate liquor flow to ensure sufficient liquid to gas contact to scrub particulate from the gas prior to it being exhausted to the atmosphere. Monitoring the pH of the scrubber liquid indicates if the scrubber liquid is performing sufficiently. Likewise, the gas pressure drop indicates that there is sufficient air flow to support gas to liquid contact to scrub particulate from the gas prior to it being exhausted to the atmosphere. The minimum scrubber liquor flow rate, the scrubber liquid pH, and the minimum gas pressure drop is monitored to ensure that the scrubber is operating properly. When the scrubber is operating properly, the particulate emissions from the exhaust of the E2 Plant Brinks Scrubber will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameters were selected based on vender recommendations, as influenced by site specific design considerations. Subsequent stack testing has confirmed that the indicator levels are appropriate. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

KT Plant Dryer/Cooler Scrubber

I. KT Plant Dryer/Cooler Scrubber Background

A. Emissions Unit

Description:	KT Plant Dryer/Cooler Scrubber
Identification:	SN-15
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter (PM):	0.7 lb/hr
Monitoring Requirements:	Scrubber liquid pH, liquid flow rate, and amperage

C. Control Technology

Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

1. Scrubber liquid pH
2. Minimum liquid flow rate
3. Minimum amperage

B. Measurement Approach

The scrubber liquid pH, the liquid flow rate, and the amperage shall be measured and recorded daily.

C. Indicator Range

1. The scrubber liquid pH range is 0.5 – 4.5.
2. The minimum scrubber liquid flow rate is 80 gal/min.
3. The minimum amperage is 290 amps.

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Calibration of the monitoring devices will be performed once per year.
Monitoring Frequency and Data:	The scrubber liquid pH, liquid flow rate, and scrubber amperage will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A wet scrubber with a mist eliminator is used to control the PM emissions generated by the KT Plant Dry/Cooler. The scrubber has a maximum gas flow rate of 48,000 ft^3/min.

B. Rationale for Selection of Performance Indicator

The scrubber liquid pH and flow rate were selected as the performance indicators because they are indicative of operation of the scrubber in a manner necessary to comply with the PM emission standard. The scrubber liquid flow rate indicates that there is adequate liquid flow to ensure sufficient liquid to gas contact to scrub PM from the gas prior to it being exhausted to the atmosphere. Monitoring the pH of the scrubber liquid indicates if the scrubber liquid is performing sufficiently. Likewise, the fan amperage indicates that there is sufficient air flow to support gas to liquid contact to scrub PM from the gas prior to it being exhausted to the atmosphere. The minimum scrubber liquid flow rate, the scrubber liquid pH, and the minimum fan amperage is monitored to ensure that the scrubber is operating properly. When the scrubber is operating properly, the PM emissions from the exhaust of the KT Plant Dryer/Cooler Scrubber will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameters were selected based on vender recommendations, as influenced by site specific design considerations. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

Compliance Assurance Monitoring

KT Plant Clay Baghouse

I. KT Plant Clay Baghouse

A. Emissions Unit

Description:	KT Plant Clay Baghouse
Identification:	SN-18
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter (PM):	1.5 lb/hr
Monitoring Requirements:	Gas pressure drop across the baghouse

C. Control Technology

Baghouse

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

Gas pressure drop

B. Measurement Approach

The gas pressure drop across the baghouse will be measured and recorded daily.

C. Indicator Range

0.5" H_2O – 8.0" H_2O

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Preventative maintenance inspection will be performed once per year.
Monitoring Frequency and Data:	The gas pressure drop across the baghouse will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A baghouse is used to control PM emissions generated by the KT Plant.

B. Rationale for Selection of Performance Indicator

The gas pressure drop across the baghouse was selected as the performance indicator because it is indicative of operation of the baghouse in a manner necessary to comply with the PM emission standard. The gas pressure drop across the baghouse indicates the amount of particle build up on the filter media. A freshly cleaned baghouse will have an estimated gas pressure drop of 0.5" H_2O. When the gas pressure drop reaches 8.0" H_2O, the filter media will be cleaned. When the baghouse is operating properly, the PM emissions from the KT Plant Clay Baghouse will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameter was selected based on vender recommendations, as influenced by site specific design considerations. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

Compliance Assurance Monitoring

KT Brinks Scrubber

I. KT Brinks Scrubber

A. Emissions Unit

Description:	KT Brinks Scrubber
Identification:	SN-21
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R14, Title V Permit
Emission Limits:	
Particulate Matter (PM):	0.3 lb/hr
Monitoring Requirements:	Scrubber liquid pH, liquid gas pressure to top spray nozzles, and gas pressure drop across unit

C. Control Technology

Scrubber

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

1. Scrubber liquid pH
2. Liquid gas pressure to top spray nozzles
3. Minimum gas pressure drop across unit

B. Measurement Approach

The scrubber liquid flow rate, liquid gas pressure, and gas pressure drop will be measured and recorded daily.

C. Indicator Range

1. The scrubber liquor pH range is 0.5 – 4.5.
2. The liquid gas pressure to top spray nozzles range is 80 – 100 psig.
3. The minimum gas pressure drop across unit is 2.5" H_2O.

D. QIP Threshold

The QIP threshold is nine excursions in a six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Calibration of the monitoring devices will be performed once per year.
Monitoring Frequency and Data:	The scrubber liquid pH, liquid gas pressure to top spray nozzles, and gas pressure drop across unit will be measured and recorded daily.
Collection Procedure:	Monitoring device.

III. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A Brinks scrubber is used to control PM emissions generated by the KT Plant. The scrubber has a maximum gas flow rate of 8,835 acfm.

B. Rationale for Selection of Performance Indicator

The scrubber liquid pH, liquid gas pressure to top spray nozzles, and gas pressure drop across unit were selected as the performance indicators because they are indicative of operation of the scrubber in a manner necessary to comply with the PM emission standard. The scrubber liquid pH indicates that the scrubber liquid is performing properly to scrub PM from the gas prior to it being exhausted to the atmosphere. Likewise, the liquid gas pressure to the top spray nozzles and the gas pressure drop indicates that there is sufficient air flow to support gas to liquid contact to scrub PM from the gas prior to it being exhausted to the atmosphere. The selected performance indicators will be monitored daily to ensure that the scrubber is operating properly. When the scrubber is operating properly, the PM emissions from the exhaust of the KT Plant Brinks Scrubber will not exceed permitted limits.

C. Rationale for Selection of Indicator Level

The indicator parameters were selected based on vender recommendations, as influenced by site specific design considerations. Daily monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

Compliance Assurance Monitoring

Ammonia Plant Primary Reformer

I. Ammonia Plant Background

A. Emissions Unit

Description:	Ammonia Plant Primary Reformer
Identification:	SN-49
Facility:	EDCC

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	573-AOP-R15, Title V Permit
Emission Limits:	
Nitrogen oxide:	9.9 lb/hr
Monitoring Requirements:	Nitrogen oxide (NO_x) emissions

C. Control Technology

Selective Catalytic Reduction (SCR) Unit

II. Monitoring Approach

The key elements of the monitoring approach are presented below:

A. Indicator

SCR inlet flow gas temperature and ammonia feed rate

B. Measurement Approach

Continuously monitor temperature of inlet gas and ammonia feed rate to SCR

C. Indicator Range

Vendor specifications for minimum SCR inlet gas temperature and ammonia feed rate

D. QIP Threshold

The QIP threshold is nine excursions in six month reporting period.

E. Performance Criteria

Data Representativeness:	Measurements are being made at the emission point.
Verification of Operational Status:	Not Applicable
QA/QC Practices and Criteria:	Calibration of the monitoring devices will be performed once per year.
Monitoring Frequency and Data:	Continuously monitor SCR inlet gas temperature and ammonia feed rate.
Collection Procedure:	Monitoring devices.

II. Justification

A. Background

EDCC operates a chemical manufacturing plant in El Dorado, Arkansas. A SCR is used to control NO_x emissions generated at the Ammonia Plant Primary Reformer.

B. Rationale for Selection of Performance Indicator

Monitoring the temperature of the inlet gas to the SCR and the ammonia feed rate per vendor specifications will ensure that the minimum temperature and ammonia feed rate needed for efficient catalytic reduction is maintained.

C. Rationale for Selection of Indicator Level

The indicator parameters were selected based on vender recommendations, as influenced by site specific design considerations. Continuous monitoring is considered adequate to demonstrate compliance considering that post-control potential to emit is less than major source thresholds.

APPENDIX H

Continuous Emission Monitoring Systems Conditions

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised September 2013

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the Relative Accuracy Test Audit (RATA), Relative Accuracy Audit (RAA), or Cylinder Gas Audit (CGA) which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

** Only CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75 shall comply with this section.

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval, the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ

CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

** All CEMS/COMS shall comply with this section.

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 business days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Quarterly reports shall be used by the Department to determine compliance with the permit.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

** Only CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75 shall comply with this section.

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
    a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
    a. Out-of-control period determination
    b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
    a. CEMS/COMS information
        1) Manufacture
        2) Model number
        3) Serial number
    b. Scheduled activities (check list)
    c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

APPENDIX I

40 CFR Part 63, Subpart CCCCCC – *National Emission Standards For Hazardous Air Pollutants For Source Category: Gasoline Dispensing Facilities*

Subpart CCCCCC—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

Contents

SOURCE: 73 FR 1945, Jan. 10, 2008, unless otherwise noted.

WHAT THIS SUBPART COVERS

§63.11110 What is the purpose of this subpart?

This subpart establishes national emission limitations and management practices for hazardous air pollutants (HAP) emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF). This subpart also establishes requirements to demonstrate compliance with the emission limitations and management practices.

§63.11111 Am I subject to the requirements in this subpart?

(a) The affected source to which this subpart applies is each GDF that is located at an area source. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank.

(b) If your GDF has a monthly throughput of less than 10,000 gallons of gasoline, you must comply with the requirements in §63.11116.

(c) If your GDF has a monthly throughput of 10,000 gallons of gasoline or more, you must comply with the requirements in §63.11117.

(d) If your GDF has a monthly throughput of 100,000 gallons of gasoline or more, you must comply with the requirements in §63.11118.

(e) An affected source shall, upon request by the Administrator, demonstrate that their monthly throughput is less than the 10,000-gallon or the 100,000-gallon threshold level, as applicable. For new or reconstructed affected sources, as specified in §63.11112(b) and (c), recordkeeping to document monthly throughput must begin upon startup of the affected source. For existing sources, as specified in §63.11112(d), recordkeeping to document monthly throughput must begin on January 10, 2008. For existing sources that are subject to this subpart only because they load gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, recordkeeping to document monthly throughput must begin on January 24, 2011. Records required under this paragraph shall be kept for a period of 5 years.

(f) If you are an owner or operator of affected sources, as defined in paragraph (a) of this section, you are not required to obtain a permit under 40 CFR part 70 or 40 CFR part 71 as a result of being subject to this subpart. However, you must still apply for and obtain a permit under 40 CFR part 70 or 40 CFR part 71 if you meet one or more of the applicability criteria found in 40 CFR 70.3(a) and (b) or 40 CFR 71.3(a) and (b).

(g) The loading of aviation gasoline into storage tanks at airports, and the subsequent transfer of aviation gasoline within the airport, is not subject to this subpart.

(h) Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.

(i) If your affected source's throughput ever exceeds an applicable throughput threshold, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold.

(j) The dispensing of gasoline from a fixed gasoline storage tank at a GDF into a portable gasoline tank for the on-site delivery and subsequent dispensing of the gasoline into the fuel tank of a motor vehicle or other gasoline-fueled engine or equipment used within the area source is only subject to §63.11116 of this subpart.

(k) For any affected source subject to the provisions of this subpart and another Federal rule, you may elect to comply only with the more stringent provisions of the applicable subparts. You must consider all provisions of the rules, including monitoring, recordkeeping, and reporting. You must identify the affected source and provisions with which you will comply in your Notification of Compliance Status required under §63.11124. You also must demonstrate in your Notification of Compliance Status that each provision with which you will comply is at least as stringent as the otherwise applicable requirements in this subpart. You are responsible for making accurate determinations concerning the more stringent provisions, and noncompliance with this rule is not excused if it is later determined that your determination was in error, and, as a result, you are violating this subpart. Compliance with this rule is your responsibility and the Notification of Compliance Status does not alter or affect that responsibility.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4181, Jan. 24, 2011]

§63.11112 What parts of my affected source does this subpart cover?

(a) The emission sources to which this subpart applies are gasoline storage tanks and associated equipment components in vapor or liquid gasoline service at new, reconstructed, or existing GDF that meet the criteria specified in §63.11111. Pressure/Vacuum vents on gasoline storage tanks and the equipment necessary to unload product from cargo tanks into the storage tanks at GDF are covered emission sources. The equipment used for the refueling of motor vehicles is not covered by this subpart.

(b) An affected source is a new affected source if you commenced construction on the affected source after November 9, 2006, and you meet the applicability criteria in §63.11111 at the time you commenced operation.

(c) An affected source is reconstructed if you meet the criteria for reconstruction as defined in §63.2.

(d) An affected source is an existing affected source if it is not new or reconstructed.

§63.11113 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraphs (a)(1) and (2) of this section, except as specified in paragraph (d) of this section.

(1) If you start up your affected source before January 10, 2008, you must comply with the standards in this subpart no later than January 10, 2008.

(2) If you start up your affected source after January 10, 2008, you must comply with the standards in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the standards in this subpart no later than January 10, 2011.

(c) If you have an existing affected source that becomes subject to the control requirements in this subpart because of an increase in the monthly throughput, as specified in §63.11111(c) or §63.11111(d), you must comply with the standards in this subpart no later than 3 years after the affected source becomes subject to the control requirements in this subpart.

(d) If you have a new or reconstructed affected source and you are complying with Table 1 to this subpart, you must comply according to paragraphs (d)(1) and (2) of this section.

(1) If you start up your affected source from November 9, 2006 to September 23, 2008, you must comply no later than September 23, 2008.

(2) If you start up your affected source after September 23, 2008, you must comply upon startup of your affected source.

(e) The initial compliance demonstration test required under §63.11120(a)(1) and (2) must be conducted as specified in paragraphs (e)(1) and (2) of this section.

(1) If you have a new or reconstructed affected source, you must conduct the initial compliance test upon installation of the complete vapor balance system.

(2) If you have an existing affected source, you must conduct the initial compliance test as specified in paragraphs (e)(2)(i) or (e)(2)(ii) of this section.

(i) For vapor balance systems installed on or before December 15, 2009, you must test no later than 180 days after the applicable compliance date specified in paragraphs (b) or (c) of this section.

(ii) For vapor balance systems installed after December 15, 2009, you must test upon installation of the complete vapor balance system.

(f) If your GDF is subject to the control requirements in this subpart only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, you must comply with the standards in this subpart as specified in paragraphs (f)(1) or (f)(2) of this section.

(1) If your GDF is an existing facility, you must comply by January 24, 2014.

(2) If your GDF is a new or reconstructed facility, you must comply by the dates specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) If you start up your GDF after December 15, 2009, but before January 24, 2011, you must comply no later than January 24, 2011.

(ii) If you start up your GDF after January 24, 2011, you must comply upon startup of your GDF.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4181, Jan. 24, 2011]

EMISSION LIMITATIONS AND MANAGEMENT PRACTICES

§63.11115 What are my general duties to minimize emissions?

Each owner or operator of an affected source under this subpart must comply with the requirements of paragraphs (a) and (b) of this section.

(a) You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must keep applicable records and submit reports as specified in §63.11125(d) and §63.11126(b).

[76 FR 4182, Jan. 24, 2011]

§63.11116 Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline.

(a) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

(b) You are not required to submit notifications or reports as specified in §63.11125, §63.11126, or subpart A of this part, but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(c) You must comply with the requirements of this subpart by the applicable dates specified in §63.11113.

(d) Portable gasoline containers that meet the requirements of 40 CFR part 59, subpart F, are considered acceptable for compliance with paragraph (a)(3) of this section.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4182, Jan. 24, 2011]

§63.11117 Requirements for facilities with monthly throughput of 10,000 gallons of gasoline or more.

(a) You must comply with the requirements in section §63.11116(a).

(b) Except as specified in paragraph (c) of this section, you must only load gasoline into storage tanks at your facility by utilizing submerged filling, as defined in §63.11132, and as specified in paragraphs (b)(1), (b)(2), or (b)(3) of this section. The applicable distances in paragraphs (b)(1) and (2) shall be measured from the point in the opening of the submerged fill pipe that is the greatest distance from the bottom of the storage tank.

(1) Submerged fill pipes installed on or before November 9, 2006, must be no more than 12 inches from the bottom of the tank.

(2) Submerged fill pipes installed after November 9, 2006, must be no more than 6 inches from the bottom of the tank.

(3) Submerged fill pipes not meeting the specifications of paragraphs (b)(1) or (b)(2) of this section are allowed if the owner or operator can demonstrate that the liquid level in the tank is always above the entire opening of the fill pipe. Documentation providing such demonstration must be made available for inspection by the Administrator's delegated representative during the course of a site visit.

(c) Gasoline storage tanks with a capacity of less than 250 gallons are not required to comply with the submerged fill requirements in paragraph (b) of this section, but must comply only with all of the requirements in §63.11116.

(d) You must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(e) You must submit the applicable notifications as required under §63.11124(a).

(f) You must comply with the requirements of this subpart by the applicable dates contained in §63.11113.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008; 76 FR 4182, Jan. 24, 2011]

§63.11118 Requirements for facilities with monthly throughput of 100,000 gallons of gasoline or more.

(a) You must comply with the requirements in §§63.11116(a) and 63.11117(b).

(b) Except as provided in paragraph (c) of this section, you must meet the requirements in either paragraph (b)(1) or paragraph (b)(2) of this section.

(1) Each management practice in Table 1 to this subpart that applies to your GDF.

(2) If, prior to January 10, 2008, you satisfy the requirements in both paragraphs (b)(2)(i) and (ii) of this section, you will be deemed in compliance with this subsection.

(i) You operate a vapor balance system at your GDF that meets the requirements of either paragraph (b)(2)(i)(A) or paragraph (b)(2)(i)(B) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraph (b)(2)(i)(A) or paragraph (b)(2)(i)(B) of this section.

(c) The emission sources listed in paragraphs (c)(1) through (3) of this section are not required to comply with the control requirements in paragraph (b) of this section, but must comply with the requirements in §63.11117.

(1) Gasoline storage tanks with a capacity of less than 250 gallons that are constructed after January 10, 2008.

(2) Gasoline storage tanks with a capacity of less than 2,000 gallons that were constructed before January 10, 2008.

(3) Gasoline storage tanks equipped with floating roofs, or the equivalent.

(d) Cargo tanks unloading at GDF must comply with the management practices in Table 2 to this subpart.

(e) You must comply with the applicable testing requirements contained in §63.11120.

(f) You must submit the applicable notifications as required under §63.11124.

(g) You must keep records and submit reports as specified in §§63.11125 and 63.11126.

(h) You must comply with the requirements of this subpart by the applicable dates contained in §63.11113.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008]

TESTING AND MONITORING REQUIREMENTS

§63.11120 What testing and monitoring requirements must I meet?

(a) Each owner or operator, at the time of installation, as specified in §63.11113(e), of a vapor balance system required under §63.11118(b)(1), and every 3 years thereafter, must comply with the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must demonstrate compliance with the leak rate and cracking pressure requirements, specified in item 1(g) of Table 1 to this subpart, for pressure-vacuum vent valves installed on your gasoline storage tanks using the test methods identified in paragraph (a)(1)(i) or paragraph (a)(1)(ii) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.1E,—Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves, adopted October 8, 2003 (incorporated by reference, see §63.14).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(2) You must demonstrate compliance with the static pressure performance requirement specified in item 1(h) of Table 1 to this subpart for your vapor balance system by conducting a static pressure test on your gasoline storage tanks using the test methods identified in paragraphs (a)(2)(i), (a)(2)(ii), or (a)(2)(iii) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.3,—Determination of 2-Inch WC Static Pressure Performance of Vapor Recovery Systems of Dispensing Facilities, adopted April 12, 1996, and amended March 17, 1999 (incorporated by reference, see §63.14).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(iii) Bay Area Air Quality Management District Source Test Procedure ST-30—Static Pressure Integrity Test—Underground Storage Tanks, adopted November 30, 1983, and amended December 21, 1994 (incorporated by reference, *see* §63.14).

(b) Each owner or operator choosing, under the provisions of §63.6(g), to use a vapor balance system other than that described in Table 1 to this subpart must demonstrate to the Administrator or delegated authority under paragraph §63.11131(a) of this subpart, the equivalency of their vapor balance system to that described in Table 1 to this subpart using the procedures specified in paragraphs (b)(1) through (3) of this section.

(1) You must demonstrate initial compliance by conducting an initial performance test on the vapor balance system to demonstrate that the vapor balance system achieves 95 percent reduction using the California Air Resources Board Vapor Recovery Test Procedure TP-201.1,—Volumetric Efficiency for Phase I Vapor Recovery Systems, adopted April 12, 1996, and amended February 1, 2001, and October 8, 2003, (incorporated by reference, see §63.14).

(2) You must, during the initial performance test required under paragraph (b)(1) of this section, determine and document alternative acceptable values for the leak rate and cracking pressure

requirements specified in item 1(g) of Table 1 to this subpart and for the static pressure performance requirement in item 1(h) of Table 1 to this subpart.

(3) You must comply with the testing requirements specified in paragraph (a) of this section.

(c) Conduct of performance tests. Performance tests conducted for this subpart shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance (*i.e.,* performance based on normal operating conditions) of the affected source. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(d) Owners and operators of gasoline cargo tanks subject to the provisions of Table 2 to this subpart must conduct annual certification testing according to the vapor tightness testing requirements found in §63.11092(f).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4182, Jan. 24, 2011]

NOTIFICATIONS, RECORDS, AND REPORTS

§63.11124 What notifications must I submit and when?

(a) Each owner or operator subject to the control requirements in §63.11117 must comply with paragraphs (a)(1) through (3) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or at the time you become subject to the control requirements in §63.11117, unless you meet the requirements in paragraph (a)(3) of this section. If your affected source is subject to the control requirements in §63.11117 only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, you must submit the Initial Notification by May 24, 2011. The Initial Notification must contain the information specified in paragraphs (a)(1)(i) through (iii) of this section. The notification must be submitted to the applicable EPA Regional Office and delegated State authority as specified in §63.13.

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of §63.11117 that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in §63.13, within 60 days of the applicable compliance date specified in §63.11113, unless you meet the requirements in paragraph (a)(3) of this section. The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facilities' monthly throughput is calculated based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under paragraph (a)(1) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under paragraph (a)(1) of this section.

(3) If, prior to January 10, 2008, you are operating in compliance with an enforceable State, local, or tribal rule or permit that requires submerged fill as specified in §63.11117(b), you are not required to

submit an Initial Notification or a Notification of Compliance Status under paragraph (a)(1) or paragraph (a)(2) of this section.

(b) Each owner or operator subject to the control requirements in §63.11118 must comply with paragraphs (b)(1) through (5) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or at the time you become subject to the control requirements in §63.11118. If your affected source is subject to the control requirements in §63.11118 only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, you must submit the Initial Notification by May 24, 2011. The Initial Notification must contain the information specified in paragraphs (b)(1)(i) through (iii) of this section. The notification must be submitted to the applicable EPA Regional Office and delegated State authority as specified in §63.13.

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of §63.11118 that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in §63.13, in accordance with the schedule specified in §63.9(h). The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facility's throughput is determined based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under paragraph (b)(1) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under paragraph (b)(1) of this section.

(3) If, prior to January 10, 2008, you satisfy the requirements in both paragraphs (b)(3)(i) and (ii) of this section, you are not required to submit an Initial Notification or a Notification of Compliance Status under paragraph (b)(1) or paragraph (b)(2) of this subsection.

(i) You operate a vapor balance system at your gasoline dispensing facility that meets the requirements of either paragraphs (b)(3)(i)(A) or (b)(3)(i)(B) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraphs (b)(3)(i)(A) or (b)(3)(i)(B) of this section.

(4) You must submit a Notification of Performance Test, as specified in §63.9(e), prior to initiating testing required by §63.11120(a) and (b).

(5) You must submit additional notifications specified in §63.9, as applicable.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008; 76 FR 4182, Jan. 24, 2011]

§63.11125 What are my recordkeeping requirements?

(a) Each owner or operator subject to the management practices in §63.11118 must keep records of all tests performed under §63.11120(a) and (b).

(b) Records required under paragraph (a) of this section shall be kept for a period of 5 years and shall be made available for inspection by the Administrator's delegated representatives during the course of a site visit.

(c) Each owner or operator of a gasoline cargo tank subject to the management practices in Table 2 to this subpart must keep records documenting vapor tightness testing for a period of 5 years. Documentation must include each of the items specified in §63.11094(b)(2)(i) through (viii). Records of vapor tightness testing must be retained as specified in either paragraph (c)(1) or paragraph (c)(2) of this section.

(1) The owner or operator must keep all vapor tightness testing records with the cargo tank.

(2) As an alternative to keeping all records with the cargo tank, the owner or operator may comply with the requirements of paragraphs (c)(2)(i) and (ii) of this section.

(i) The owner or operator may keep records of only the most recent vapor tightness test with the cargo tank, and keep records for the previous 4 years at their office or another central location.

(ii) Vapor tightness testing records that are kept at a location other than with the cargo tank must be instantly available (*e.g.,* via e-mail or facsimile) to the Administrator's delegated representative during the course of a site visit or within a mutually agreeable time frame. Such records must be an exact duplicate image of the original paper copy record with certifying signatures.

(d) Each owner or operator of an affected source under this subpart shall keep records as specified in paragraphs (d)(1) and (2) of this section.

(1) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.11115(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

§63.11126 What are my reporting requirements?

(a) Each owner or operator subject to the management practices in §63.11118 shall report to the Administrator the results of all volumetric efficiency tests required under §63.11120(b). Reports submitted under this paragraph must be submitted within 180 days of the completion of the performance testing.

(b) Each owner or operator of an affected source under this subpart shall report, by March 15 of each year, the number, duration, and a brief description of each type of malfunction which occurred during the previous calendar year and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.11115(a), including actions taken to correct a malfunction. No report is necessary for a calendar year in which no malfunctions occurred.

[76 FR 4183, Jan. 24, 2011]

OTHER REQUIREMENTS AND INFORMATION

§63.11130 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions apply to you.

§63.11131 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as the applicable State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in paragraphs (c)(1) through (3) of this section.

(1) Approval of alternatives to the requirements in §§63.11116 through 63.11118 and 63.11120.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

§63.11132 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA), or in subparts A and BBBBBB of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Dual-point vapor balance system means a type of vapor balance system in which the storage tank is equipped with an entry port for a gasoline fill pipe and a separate exit port for a vapor connection.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater, which is used as a fuel for internal combustion engines.

Gasoline cargo tank means a delivery tank truck or railcar which is loading or unloading gasoline, or which has loaded or unloaded gasoline on the immediately previous load.

Gasoline dispensing facility (GDF) means any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine, including a nonroad vehicle or nonroad engine used solely for competition. These facilities include, but are not limited to, facilities that dispense gasoline into on- and off-road, street, or highway motor vehicles, lawn equipment, boats, test engines, landscaping equipment, generators, pumps, and other gasoline-fueled engines and equipment.

Monthly throughput means the total volume of gasoline that is loaded into, or dispensed from, all gasoline storage tanks at each GDF during a month. Monthly throughput is calculated by summing the volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the current day, plus the total volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the previous 364 days, and then dividing that sum by 12.

Motor vehicle means any self-propelled vehicle designed for transporting persons or property on a street or highway.

Nonroad engine means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 7411 of this title or section 7521 of this title.

Nonroad vehicle means a vehicle that is powered by a nonroad engine, and that is not a motor vehicle or a vehicle used solely for competition.

Submerged filling means, for the purposes of this subpart, the filling of a gasoline storage tank through a submerged fill pipe whose discharge is no more than the applicable distance specified in §63.11117(b) from the bottom of the tank. Bottom filling of gasoline storage tanks is included in this definition.

Vapor balance system means a combination of pipes and hoses that create a closed system between the vapor spaces of an unloading gasoline cargo tank and a receiving storage tank such that vapors displaced from the storage tank are transferred to the gasoline cargo tank being unloaded.

Vapor-tight means equipment that allows no loss of vapors. Compliance with vapor-tight requirements can be determined by checking to ensure that the concentration at a potential leak source is not equal to or greater than 100 percent of the Lower Explosive Limit when measured with a combustible gas detector, calibrated with propane, at a distance of 1 inch from the source.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in §63.11092(f) of this part.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

Table 1 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More[1]

If you own or operate	Then you must
1. A new, reconstructed, or existing GDF subject to §63.11118	Install and operate a vapor balance system on your gasoline storage tanks that meets the design criteria in paragraphs (a) through (h).
	(a) All vapor connections and lines on the storage tank shall be equipped with closures that seal upon disconnect.
	(b) The vapor line from the gasoline storage tank to the gasoline cargo tank shall be vapor-tight, as defined in §63.11132.
	(c) The vapor balance system shall be designed such that the pressure in the tank truck does not exceed 18 inches water pressure or 5.9 inches water vacuum during product transfer.
	(d) The vapor recovery and product adaptors, and the method of

	connection with the delivery elbow, shall be designed so as to prevent the over-tightening or loosening of fittings during normal delivery operations.
	(e) If a gauge well separate from the fill tube is used, it shall be provided with a submerged drop tube that extends the same distance from the bottom of the storage tank as specified in §63.11117(b).
	(f) Liquid fill connections for all systems shall be equipped with vapor-tight caps.
	(g) Pressure/vacuum (PV) vent valves shall be installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water. The total leak rate of all PV vent valves at an affected facility, including connections, shall not exceed 0.17 cubic foot per hour at a pressure of 2.0 inches of water and 0.63 cubic foot per hour at a vacuum of 4 inches of water.
	(h) The vapor balance system shall be capable of meeting the static pressure performance requirement of the following equation:
	$Pf = 2e^{-500.887/v}$
	Where:
	Pf = Minimum allowable final pressure, inches of water.
	v = Total ullage affected by the test, gallons.
	e = Dimensionless constant equal to approximately 2.718.
	2 = The initial pressure, inches water.
2. A new or reconstructed GDF, or any storage tank(s) constructed after November 9, 2006, at an existing affected facility subject to §63.11118	Equip your gasoline storage tanks with a dual-point vapor balance system, as defined in §63.11132, and comply with the requirements of item 1 in this Table.

[1]The management practices specified in this Table are not applicable if you are complying with the requirements in §63.11118(b)(2), except that if you are complying with the requirements in §63.11118(b)(2)(i)(B), you must operate using management practices at least as stringent as those listed in this Table.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4184, Jan. 24, 2011]

Table 2 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Cargo Tanks Unloading at Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More

If you own or operate	Then you must
A gasoline cargo tank	Not unload gasoline into a storage tank at a GDF subject to the control requirements in this subpart unless the following conditions are met:
	(i) All hoses in the vapor balance system are properly connected,

	(ii) The adapters or couplers that attach to the vapor line on the storage tank have closures that seal upon disconnect,
	(iii) All vapor return hoses, couplers, and adapters used in the gasoline delivery are vapor-tight,
	(iv) All tank truck vapor return equipment is compatible in size and forms a vapor-tight connection with the vapor balance equipment on the GDF storage tank, and
	(v) All hatches on the tank truck are closed and securely fastened.
	(vi) The filling of storage tanks at GDF shall be limited to unloading from vapor-tight gasoline cargo tanks. Documentation that the cargo tank has met the specifications of EPA Method 27 shall be carried with the cargo tank, as specified in §63.11125(c).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

Table 3 to Subpart CCCCCC of Part 63—Applicability of General Provisions

Citation	Subject	Brief description	Applies to subpart CCCCCC
§63.1	Applicability	Initial applicability determination; applicability after standard established; permit requirements; extensions, notifications	Yes, specific requirements given in §63.11111.
§63.1(c)(2)	Title V Permit	Requirements for obtaining a title V permit from the applicable permitting authority	Yes, §63.11111(f) of subpart CCCCCC exempts identified area sources from the obligation to obtain title V operating permits.
§63.2	Definitions	Definitions for part 63 standards	Yes, additional definitions in §63.11132.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, severability	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes, except that these notifications are not required for facilities subject to §63.11116
§63.6(a)	Compliance with Standards/Operation & Maintenance—Applicability	General Provisions apply unless compliance extension; General Provisions apply to area sources that	Yes.

		become major	
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for CAA section 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	No.
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for CAA section 112(f) standards, comply within 90 days of effective date unless compliance extension	No, §63.11113 specifies the compliance dates.
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources That become major must comply with major source standards by date indicated in this subpart or by equivalent time period (e.g., 3 years)	No.
§63.6(d)	[Reserved]		
63.6(e)(1)(i)	General duty to minimize emissions	Operate to minimize emissions at all times; information Administrator will use to determine if operation and maintenance requirements were met.	No. *See* §63.11115 for general duty requirement.
63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Owner or operator must correct malfunctions as soon as possible.	No.
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	No.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	No.
§63.6(f)(2)-(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)(1)	Compliance with	You must comply with opacity/VE	No.

	Opacity/Visible Emission (VE) Standards	standards at all times except during SSM	
§63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	If standard does not State test method, use EPA Method 9 for opacity in appendix A of part 60 of this chapter and EPA Method 22 for VE in appendix A of part 60 of this chapter	No.
§63.6(h)(2)(ii)	[Reserved]		
§63.6(h)(2)(iii)	Using Previous Tests To Demonstrate Compliance With Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart	No.
§63.6(h)(3)	[Reserved]		
§63.6(h)(4)	Notification of Opacity/VE Observation Date	Must notify Administrator of anticipated date of observation	No.
§63.6(h)(5)(i), (iii)-(v)	Conducting Opacity/VE Observations	Dates and schedule for conducting opacity/VE observations	No.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times	Must have at least 3 hours of observation with 30 6-minute averages	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Must keep records available and allow Administrator to inspect	No.
§63.6(h)(7)(i)	Report Continuous Opacity Monitoring System (COMS) Monitoring Data From Performance Test	Must submit COMS data with other performance test data	No.
§63.6(h)(7)(ii)	Using COMS Instead of EPA Method 9	Can submit COMS data instead of EPA Method 9 results even if rule requires EPA Method 9 in appendix A of part 60 of this chapter, but must notify Administrator before performance test	No.
§63.6(h)(7)(iii)	Averaging Time for COMS During Performance Test	To determine compliance, must reduce COMS data to 6-minute averages	No.
§63.6(h)(7)(iv)	COMS Requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to §63.8(e); COMS are properly maintained and operated according to §63.8(c) and data quality as §63.8(d)	No.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	COMS is probable but not conclusive evidence of compliance with opacity standard, even if EPA Method 9 observation shows otherwise. Requirements for COMS to be probable evidence-proper maintenance, meeting Performance Specification 1 in appendix B of part	No.

		60 of this chapter, and data have not been altered	
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all COMS, EPA Method 9 (in appendix A of part 60 of this chapter), and EPA Method 22 (in appendix A of part 60 of this chapter) results, as well as information about operation and maintenance to determine compliance	No.
§63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	No.
§63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§63.7(a)(3)	CAA Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Re-scheduling	If have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
63.7(e)(1)	Conditions for Conducting Performance Tests	Performance test must be conducted under representative conditions	No, §63.11120(c) specifies conditions for conducting performance tests.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.
§63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1	Yes.

		hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in §63.11 apply	Yes.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	No.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	No.
§63.8(c)(1)(i)-(iii)	Operation and Maintenance of Continuous Monitoring Systems (CMS)	Must maintain and operate each CMS as specified in §63.6(e)(1); must keep parts for routine repairs readily available; must develop a written SSM plan for CMS, as specified in §63.6(e)(3)	No.
§63.8(c)(2)-(8)	CMS Requirements	Must install to get representative	No.

		emission or parameter measurements; must verify operational status before or at performance test	
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	No.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	No.
§63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	No.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system (CEMS)	No.
§63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	No.
§63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§63.9(b)(1)-(2), (4)-(5)	Initial Notifications	Submit notification within 120 days after effective date; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications when Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes, however, there are no opacity standards.
§63.9(h)(1)-(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/VE,	Yes, however, there are no opacity

		which are due 30 days after; when to submit to Federal vs. State authority	standards.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§63.10(b)(2)(i)	Records related to SSM	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§63.10(b)(2)(ii)	Records related to SSM	Recordkeeping of malfunctions	No. *See* §63.11125(d) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§63.10(b)(2)(iii)	Maintenance records	Recordkeeping of maintenance on air pollution control and monitoring equipment	Yes.
§63.10(b)(2)(iv)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(v)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(vi)-(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	No.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§63.10(b)(3)	Records	Applicability determinations	Yes.
§63.10(c)	Records	Additional records for CMS	No.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test	When to submit to Federal or State	Yes.

	Results	authority	
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	SSM Reports	Contents and submission	No. *See* §63.11126(b) for malfunction reporting requirements.
§63.10(e)(1)-(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; two-three copies of COMS performance evaluation	No.
§63.10(e)(3)(i)-(iii)	Reports	Schedule for reporting excess emissions	No.
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No.
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No, §63.11130(K) specifies excess emission events for this subpart.
§63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS; requires all of the	No.

		information in §§63.10(c)(5)-(13) and 63.8(c)(7)-(8)	
§63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11(b)	Flares	Requirements for flares	No.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporations by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

APPENDIX J

CEMS Monitoring Plan from the EPA/DOJ/LSB global settlement

ATTACHMENT C

NITRIC ACID PLANT CEMS PLAN

CEMS Plan for NO_x Emissions
LSB Operating Nitric Acid Plants

Principle

This CEMS Plan is the mechanism for determining compliance with the Short-Term NO_x Limit and Long-Term NO_x Limit applicable to each Operating Nitric Acid Plant, as specified in the Consent Decree, and is used to evaluate the compliance status with the NSPS NO_x limits. The methodology described in this CEMS Plan will provide a continuous indication of compliance with the above-referenced NO_x emission limits established in the Consent Decree by accurately determining the emission rate in terms of pounds of NO_x emitted per ton of 100% Nitric Acid Produced (lb/ton) as a rolling 3-hour average and a rolling 365-day average. The CEMS will utilize equipment to measure the stack NO_x concentration and the stack volumetric flow rate. The 100% nitric acid production rate will be determined as allowed by NSPS Subpart G. From this data, real-time, accurate, and quality controlled measurements of the mass NO_x emission rate per unit of production can be obtained.

Definitions

Terms used in this CEMS Plan that are defined in the Clean Air Act ("CAA") or in Federal or state regulations promulgated pursuant to the CAA shall have the meaning assigned to them in the CAA or such regulations, unless otherwise defined in the Consent Decree. The terms used in this CEMS Plan that are defined in the Consent Decree shall have the meaning assigned to them therein. The following definitions specifically apply for purposes of this CEMS Plan.

- "CEMS" or "Continuous Emission Monitoring System" shall mean the total equipment, required under this CEMS Plan, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.
- "Covered Nitric Acid Plants" shall mean all ten of LSB's Nitric Acid Plants in the United States that are subject to this Consent Decree: two at the Cherokee Facility (Cherokee #1 and #2); one at the Baytown Facility (Baytown); four at the El Dorado Facility (El Dorado East, El Dorado West, El Dorado DMW, and El Dorado DSN); and three at the Pryor Facility (Pryor #1, #3, and #4);
- "Day," "day," or "calendar day" shall mean a calendar day unless expressly stated to be a working day. In computing any period of time under this Consent Decree, where the last day would fall on a Saturday, Sunday, or federal or State holiday, the period shall run until the close of business of the next working day;
- "DSCFH" shall mean dry standard cubic feet per hour.
- "Interim NOx Emissions Limit" or "IL" shall mean a 3-hour rolling average NO_x emission limit (rolled hourly) expressed in terms of pounds of NO_x emitted per ton of

100% Nitric Acid Produced ("lb/ton"); compliance with the Interim NO_x Emissions Limit shall be calculated in accordance with this CEMS Plan. The Interim NO_x Emissions Limit does not apply during periods of Startup, Shutdown, or Malfunction;

- "Long-Term NO_x Emissions Limit" or "LTL" shall mean a 365-day rolling average NO_x emission limit (rolled daily) expressed as pounds of NO_x emitted per ton of 100% Nitric Acid Produced ("lb/ton"); compliance with the Long-Term NO_x Emissions Limit shall be calculated in accordance with this CEMS Plan. The Long-Term NO_x Emissions Limit applies at all times, including during periods of Startup, Shutdown, or Malfunction.

- "Malfunction" shall mean, consistent with 40 C.F.R. § 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, but shall not include failures that are caused in whole or in part by poor maintenance or careless operation.

- "NSPS NO_x Emissions Limit" shall mean the NO_x emission limit expressed as 1.5 kg of NO_x per metric ton of 100% Nitric Acid Produced (3 lb per ton) specified at 40 C.F.R. §60.72(a)(1).

- "NO_x" shall mean, consistent with 40 C.F.R. § 60.2, all oxides of nitrogen except nitrous oxide. (N_2O). For the purposes of calculating mass emission rates, NO_x has a molecular weight of 46.0055 lb/lb-mol.

- "NO_x Stack Analyzer" shall mean, for all Operating Nitric Acid Plants except the Baytown Plant (at all times) and El Dorado East and West Plants during only the period of required compliance demonstration with the Interim NO_x Emissions Limit under the Consent Decree, that portion of a dual range or greater CEMS that senses NO_x and generates an output proportional to the NO_x concentration during Operating Periods. For the Baytown Plant and El Dorado East and West Plants (during only the period of required compliance demonstration with the Interim NO_x Emissions Limit under the Consent Decree), "NO_x Stack Analyzer" shall mean that portion of a single range CEMS unit that senses NO_x and generates an output proportional to the NO_x concentrations during Operating Periods.

- "100% Nitric Acid" shall mean nitric acid product manufactured by a Nitric Acid Plant multiplied by the concentration of actual nitric acid in the product. For example, if a Nitric Acid Plant produces 100 tons of a 54% nitric acid product, this equals 54 tons of 100% Nitric Acid.

- "One-hour period" and "1-hour period" shall mean any 60-minute period commencing on the hour.

- "One-minute measurement" shall mean any single measurement or the arithmetic average of multiple measurements of a parameter during a one-minute period on-the-clock.

- "Operating Nitric Plants" shall mean any or all of the nine of the ten Covered Nitric Acid Plants that continue, or may continue, to operate as of the Date of Lodging (with El Dorado DSN as the excluded Covered Nitric Acid Plant under this definition due to its permanent shut-down): two at the Cherokee Facility (Cherokee #1 and #2); one at the Baytown Facility (Baytown); three at the El Dorado Facility (El Dorado East, El Dorado West, and El Dorado DMW); and three at the Pryor Facility (Pryor #1, #3, and #4);Operating Periods" shall mean periods during which an Operating Nitric Acid Plant is producing nitric acid and NO_x is emitted, including periods of Startup, Shutdown and Malfunction; "Short-Term NO_x Emissions Limit" or "STL" shall mean a 3-hour rolling average NO_x emission limit (rolled hourly) expressed in terms of pounds of NO_x emitted per ton of 100% Nitric Acid Produced ("lb/ton"); compliance with the Short-Term NO_x Emissions Limit shall be calculated in accordance with this CEMS Plan. The Short-Term NO_x Emissions Limit does not apply during periods of Startup, Shutdown, or Malfunction.

- "Shutdown" shall mean the cessation of nitric acid production operations of a Operating Nitric Acid Plant for any reason. Shutdown begins at the time the feed of ammonia to the Operating Nitric Acid Plant ceases and ends when the compressor train(s) is shut down."Stack Flowmeter" shall mean that portion of the CEMS that senses the volumetric flow rate and generates an output proportional to that flow rate.
- "Standard Cubic Foot" or "SCF" shall mean a quantity of gas equal to one cubic foot at a temperature of 68° Fahrenheit and a pressure of 14.696 pounds per square inch absolute.
- "Startup" shall mean the process of initiating nitric acid production operations of a Operating Nitric Acid Plant. Startup begins with the start of the compressor train(s) at the Operating Nitric Acid Plant and ends no more than 5 hours after the initiation of the feed of ammonia.
- "Ton" or "tons" shall mean short ton or short tons. One Ton equals 2,000 pounds.

Emissions Monitoring

Emissions monitoring under this CEMS Plan will be done using the appropriate NO_x Stack Analyzer and a stack flowmeter on each Operating Nitric Acid Plant. Except for periods of CEMS breakdowns, analyzer malfunctions, repairs, and required quality assurance or quality control activities (including calibration checks and required zero and span adjustments), Settling Defendants will demonstrate compliance with the STL, IL, and LTL during all Operating Periods by conducting continuous monitoring pursuant to this CEMS Plan at each Operating Nitric Acid Plant, as follows:

- The NO_x Stack Analyzer will measure the stack NO_x concentration, in parts per million by volume, dry basis (ppmvd)[1] and reduce the data to one-minute measurements, and the stack flowmeter will measure the volumetric flow rate in dry standard cubic feet per hour (DSCFH)[2].

[1] For the purposes of calculations under this CEMS Plan, as-is NO_x concentration measurements at Operating Nitric Plants (e.g., those utilizing FTIR, NDIR, or other types of stack gas analyzers capable of making wet measurements) will be assumed to be dry. However, LSB may adjust for any moisture contained in the stack gas if the Operating Nitric Acid Plant is equipped with a continuous moisture analyzer or equipment which removes the moisture prior to the stack gas analyzer.

[2] For the purposes of the calculations under this CEMS Plan, as-is volumetric flow rate measurements will be assumed to be dry. However, LSB may adjust for any moisture contained in the stack gas if the Operating Nitric Acid Plant is equipped with a continuous moisture analyzer.

- For every 1-hour period (60-minute period commencing on the hour), the CEMS will reduce the one-minute measurements generated by the NO_X Stack Analyzer and the stack flowmeter by taking the arithmetic average of all the one-minute measurements made during the previous 1- hour period. At least four one-minute measurements must be used to make this calculation, with at least one data point in each 15-minute quadrant of the hour.

Backup Monitoring Procedure for Long-Term NO_X Emissions Limit

In the event that the NO_X Stack Analyzer and/or stack flowmeter is/are not available or is/are out-of-control, Settling Defendants will implement the backup monitoring procedure specified below. The resulting data will be used to calculate the 365-day average NO_X emission rate.

a) Settling Defendants will comply with the following requirements to fill in data gaps in the array:

   - Exit stack gas will be sampled and analyzed for NO_X at least once every three (3) hours, during all Operating Periods. Sampling will be conducted by making physical measurements of the NO_X concentration in the gas stream to the main stack using alternative/non-CEMS methods (e.g., through the use of a portable analyzer/detector or non-certified NO_X Stack Analyzer). The reading obtained will be substituted for the 180 (or less) one-minute measurements that would otherwise be utilized if the CEMS were operating normally. Alternatively, Settling Defendants may conduct the required sampling and analysis using a redundant, certified NO_X Stack Analyzer.

   - Stack volumetric flow rate will be estimated using engineering judgment.

b) During required quality assurance or quality control activities (including calibration checks and required zero and span adjustments) of the CEMS and stack flow meter, Settling Defendants may utilize either (1) the previous calendar day average when the previous day does not include a Startup, Shutdown, or Malfunction, or (2) the average of the block hour average immediately preceding the affected analyzer's(s') stoppage and the initial block hour average of the affected analyzer's(s') upon the resumption of operation following the stoppage, when the previous calendar day includes a Startup, Shutdown or Malfunction, to fill in any data gaps in lieu of the procedures specified in subparagraph a).

c) If any one or more than one of the CEMS or stack flowmeter is/are not operating for a period of less than 24 consecutive hours due to breakdowns, malfunctions, repairs, or out-of-control period of the same, Settling Defendants may utilize either (1) the previous calendar day average when the previous day does not include a Startup, Shutdown, or Malfunction, or (2) the average of the block hour average immediately preceding the affected analyzer's(s') stoppage and the initial block hour average of the affected analyzer's(s') upon the resumption of operation following the stoppage, when the previous calendar day includes a Startup, Shutdown or Malfunction, to fill in any data gaps in lieu of the procedures specified in subparagraph a).

Production Data

Following each calendar day at each Operating Nitric Acid Plant, as allowed by NSPS Subpart G, Settling Defendants will record the quantity of nitric acid produced during that day and the average strength of the nitric acid produced during that day. From this information, Settling Defendants will calculate the 100% Nitric Acid Produced for that day, in units of tons per day.

Conversion Factor

During each performance test for each Covered Nitric Acid Plant required under Paragraph 19 of the Consent Decree, Settling Defendants will develop a conversion factor, in units of lb/ton of 100% Nitric Acid Produced per lb/hr NO_X. The conversion factor will be developed consistent with the procedures in 40 C.F.R. §60.73(b). Subsequently, Settling Defendants will reestablish the conversion factors during each Relative Accuracy Test Audit conducted in accordance with 40 C.F.R. Part 60, Appendix F.

Emissions Calculations

Rolling 3-Hour Average

Compliance with the STL and IL shall be based on a rolling 3-hour average (rolled hourly). For purposes of calculating a rolling 3-hour average NO_X emission rate, the CEMS will maintain an array of the 3 most recent and contiguous 1-hour period average measurements of the NO_X concentration measurement (ppmvd) at the exit stack and the average volumetric flow rate measurement (DSCFH) of the exit stack. Every hour, it will add the most recent 1-hour period value to the array and exclude the oldest 1-hour period value. Data generated using the backup monitoring procedure specified above need not be included in this calculation. Any data generated during periods that are not Operating Periods will not be included in this calculation.

The rolling 3-hour average lb/ton NO_X emission rate (E_{3hravg}) will then be calculated every hour using Equation 1.

Equation 1:

$$E_{3hravg} = \frac{K \cdot 1.193 \times 10^7 \sum_{i=1}^{3} Qstack_i \cdot C_{NOx\,i}}{3}$$

Where:

$C_{NOx\,i}$ = Arithmetic average of all one-minute measurements of stack NO_X concentration, parts per million by volume, dry basis (ppmvd) during 1-hour period "*i*"Q

K = Conversion factor determined during the most recent NO_X performance test or RATA (lb NO_X/ton of 100% nitric acid produced per lb/hr NO_X)

$Q_{Stack}\ i$ = Arithmetic average of all one minute measurements of stack volumetric flow rate. DSCFH during one hour period "*i*"

1.193 x 10^7 = Conversion factor in units of pounds per standard cubic foot (lb/SCF) NO_X per ppm

E_{3hravg} = 3-hour average lb NO_X per ton 100% Nitric Acid Produced

Rolling 365-Day Average

Compliance with the LTL shall be based on a rolling 365-day average (rolled daily). For the purposes of calculating the 365-day average NO_X emission rate each calendar day at each Operating Nitric Acid Plant, Settling Defendants will maintain an array of the mass emissions (lb/day) of NO_X (calculated using Equation 2) and the 100% Nitric Acid Produced for that day (tons/day) and the preceding 364 days. Each subsequent day, the data from that day will be added to the array, and the data from the oldest day will be excluded.

For the purposes of calculating the daily mass emission rate, the CEMS will maintain an array of each one-hour average NO_X concentration measurement (ppmvd) at the exit stack and each one-hour average volumetric flow rate measurement (DSCFH) of the exit stack over each day. Any partial hourly data will be adjusted on a *pro-rata* basis. In the event that one or more of the NO_X Stack Analyzers and stack flowmeters is/are not available, Settling Defendants will use the backup monitoring procedure, specified above, to fill in the data gaps. Any data generated during periods that are not Operating Periods will not be included in this calculation.

Following each calendar day, the daily NO_X mass emissions will be calculated using Equation 2.

Equation 2:

$$M_{NO_xDay} = 1.193 \times 10^{-7} \cdot \sum_{i=1}^{n} Q_{Stack\,i} \cdot C_{NOx\,i}$$

Where:

$C_{NOx\,i}$ = Arithmetic average of all one-minute measurements of stack NO_X concentration, parts per million by volume, dry basis (ppmvd) during 1-hour period "*i*"

$Q_{Stack\,i}$ = Arithmetic average of all one-minute measurements of stack volumetric flow rate, DSCFH during 1-hour period "*i*"

1.193×10^{-7} = Conversion factor in units of pounds per standard cubic foot (lb/SCF) NO_X per ppm

M_{NO_xDay} = Mass emissions of NO_X during a calendar day, lb

n = Number of hours of Operating Period in a calendar day

Following each calendar day, the NO_X emission rate as lb/ton, averaged over a rolling 365-day period ($E_{365-Day\,Avg}$), will be calculated using Equation 3.

Equation 3:

$$E_{365-Day\,Avg} = \frac{\sum_{d=1}^{365} M_{NO_xDay\,d}}{\sum_{d=1}^{365} P_d}$$

Where:

$M_{NO_xDay\,d}$ = Mass emissions of NO_X during a calendar day "*d*", lb

P_d = 100% Nitric Acid Produced during a calendar day "*d*", tons

$E_{365-Day\,Avg}$ = 365-day rolling average lb NO_X per ton of 100% Nitric Acid Produced

Rounding of Numbers Resulting from Calculations

Upon completion of the calculations, the final numbers shall be rounded as follows:

E_{3hravg}: Rounded to the nearest tenth.

$E_{365-Day\,Avg}$: Rounded to the nearest hundredth.

The numbers "5"-"9" shall be rounded up, and the numbers "1"-"4" shall be rounded down. Thus, "1.05"shall be rounded to "1.1", and "1.04" shall be rounded to "1.0".

Compliance with Consent Decree NO_X Limits

Short-Term NO_X Emissions Limits and Interim NOx Emissions Limits

The STLs and ILs do not apply during periods of Startup, Shutdown, or Malfunction. During all other Operating Periods at an Operating Nitric Acid Plant, Settling Defendants will be in compliance with the STL specified in the Consent Decree if E_{3hravg} does not exceed 1.0 lb of NO_X per ton of 100% Nitric Acid Produced and Settling Defendants will be in compliance with the IL specified in the Consent Decree if E_{3hravg} does not exceed 3.0 lb of NO_X per ton of 100% Nitric Acid Produced. If Settling Defendants contend that any 3-hour rolling average emission rate is in excess of 1.0 lb/ton for the STL or 3.0 lb/ton for the IL due to the inclusion of hours of Startup, Shutdown or Malfunction in the 3-hour period, Settling Defendants shall recalculate E_{3hravg} to exclude measurements recorded during the period(s) of the claimed Startup, Shutdown or Malfunction(s).

NSPS NO_X Emissions Limits

The NSPS NO_X Emissions Limit does not apply during periods of Startup, Shutdown, or Malfunction. During all other Operating Periods at a Operating Nitric Acid Plant, Settling Defendants will be in compliance with the NSPS Limit if E_{3hravg} does not exceed 3.0 lb of NO_X per ton of 100% Nitric Acid Produced. If Settling Defendants contend that any 3-hour rolling average emission rate is in excess of 3.0 lb/ton due to the inclusion of hours of Startup, Shutdown or Malfunction in the 3-hour period, Settling Defendants shall recalculate E_{3hravg} to exclude measurements recorded during the period(s) of the claimed Startup, Shutdown or Malfunction(s). Nothing in this CEMS Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a Operating Nitric Acid Plant would have been in compliance with the NSPS NO_X Emissions Limit if the appropriate performance test or compliance procedure had been performed.

Long-Term NO_X Emissions Limits

Settling Defendants will be in compliance with the LTL specified in the Consent Decree if $E_{365\text{-}Day\ Avg}$ does not exceed 0.60 lb of NO_X per ton of 100% Nitric Acid Produced. The LTL applies during all Operating Periods, including during periods of Startup, Shutdown, or Malfunction.

Retention of All CEMS Data, including Data, during Startup, Shutdown, and Malfunction

Settling Defendants will retain all data generated by the appropriate NO_X Stack Analyzer and Stack Flowmeter, including all data generated during periods of Startup, Shutdown, and/or Malfunction at each Operating Nitric Acid Plant in accordance with Section XIII of the Consent Decree (Information Collection and Retention).

Analyzer and Stack Flowmeter Specifications

The appropriate NO_X Stack Analyzers and the Stack Flowmeters required under this CEMS Plan at each Operating Nitric Acid Plant will meet the following specifications:

Table 1

Analyzer	Parameter	Location	Span Value
NO_x Stack Analyzers	NO_x, ppm by volume, dry basis	Stack	<u>Dual Range or greater:</u> Normal: 0 – 500 ppm NO_x, or as appropriate to accurately measure the normal concentration range. SSM: 0 to 125% of the maximum estimated NO_x emission concentration during the Operating Periods. <u>Baytown Single Range:</u> Normal and SSM: 0-200 ppm NO_x, or as appropriate to accurately measure the normal concentration range. <u>El Dorado East and West Single Range (during IL compliance period only):</u> Normal: 0-500 ppm NO_x
Stack Flowmeter	Volumetric Flow rate, SCFH	Stack	0 to 125% of the maximum expected volumetric flow rate

Further specifications for each Operating Nitric Acid Plant under this CEMS Plan are as follows:

- For the Plants utilizing dual range or greater NO_X Stack Analyzers (all Operating Nitric Acid Plants except the Baytown Plant and El Dorado East and West Plants during only the period of required IL compliance):

    - The NOx Stack Analyzer will meet all applicable requirements of 40 C.F.R. §60.11, §60.13, 40 C.F.R. Part 60, Appendix B, Performance Specification 2, and the Quality Assurance and Quality Control Procedures in 40 C.F.R. Part 60, Appendix F, Procedure 1. It should be noted, however, that the daily drift test requirement at 40 C.F.R. §60.13(d) and the requirements of Appendix F apply only to the normal range of the NO_X Stack Analyzers with a dual or greater range.
    - The SSM range of the NO_X Stack Analyzers will be evaluated once each calendar quarter, or at the next startup and shutdown opportunity if an evaluation cannot be performed during the calendar quarter, to verify accuracy. For the stack analyzer evaluations at each such Operating Nitric Acid Plant, sampling will be conducted by making physical measurements of the NO_X concentration in the gas stream to the main stack using an alternative/non-CEMS method(s) approved by the permitting authority (e.g., stack sampling and analysis, through the use of a portable analyzer/detector, or non-certified NO_X stack analyzer).

- For the Plants utilizing single range NO_X Stack Analyzers (the Baytown Plant and El Dorado East and West Plants during only the period of required IL compliance):

- The NOx Stack Analyzer will meet all applicable requirements of 40 C.F.R. §60.11, §60.13, 40 C.F.R. Part 60, Appendix B, Performance Specification 2, and the Quality Assurance and Quality Control Procedures in 40 C.F.R. Part 60, Appendix F, Procedure 1. The daily drift test requirement at 40 C.F.R. §60.13(d) and the requirements of Appendix F apply to the span of the NO_X Stack Analyzer.
- For the stack analyzer evaluations at each such Operating Nitric Acid Plant, sampling will be conducted by making physical measurements of the NO_X concentration in the gas stream to the main stack using an alternative/non-CEMS method(s) approved by the permitting authority (e.g., stack sampling and analysis, through the use of a portable analyzer/detector, or non-certified NO_X stack analyzer).
- The range of the Baytown NO_X Stack Analyzer will be evaluated once each calendar year during the annual RATA using the Quality Assurance and Quality Control Procedures in 40 C.F.R. Part 60, Appendix F, Procedure 1

- For the Stack Flowmeters at all Operating Nitric Acid Plants:

  - For the Baytown Plant only, the stack flow meter will meet 40 C.F.R. Part 60, Appendix B, Performance Specification 6 and will be evaluated once each calendar year during the RATA to verify accuracy.
  - At all other Operating Nitric Acid Plants except Baytown, the stack flow meters will meet 40 C.F.R. Part 60, Appendix B, Performance Specification 6 and will be evaluated once each calendar quarter and during the RATA of the appropriate NO_X Stack Analyzer to verify accuracy.

Compliance with the NSPS: 40 C.F.R. Part 60, Subpart G

In addition to the requirements in this CEMS Plan, Settling Defendants also will comply with all of the requirements of the NSPS relating to monitoring at each Operating Nitric Acid Plant except that, pursuant to 40 C.F.R. §60.13(i), this CEMS Plan will supersede the following provisions of 40 C.F.R. Part 60, Subpart G:

- The requirement at 40 C.F.R. §60.73(a) that the NO_X stack analyzers have a normal span value of 500 ppm. In lieu of this, Settling Defendants will utilize the span values specified in Table 1 of this CEMS Plan; and
- The requirement at 40 C.F.R. § 60.73(a) that pollutant gas mixtures under Performance Specification 2 and for calibration checks under 40 C.F.R. §60.13(d) be nitrogen dioxide (NO_2). Settling Defendants will use calibration gases containing NO and/or NO_2, as appropriate to assure accuracy of the NO_X Stack Analyzers except where verified reference cells are used in accordance with Performance Specification 2.
- The requirement at 40 C.F.R. §60.73(b) that the conversion factor be developed/expressed in the units of lb NOx per ton of 100% nitric acid produced per ppm. In lieu of this requirement, Settling Defendants will develop/express the conversion factor in the units of lb NO_X per ton of 100% nitric acid produced per lb/hr NO_X.

CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to El Dorado Chemical Company, P.O. Box 231, El Dorado, AR, 71730, on this 18th day of November, 2013.

Cynthia Hook, ASIII, Air Division