

RESPONSE TO COMMENTS

AECI - Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

On January 28, 2010 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, the facility submitted written comments, data, views, or arguments on the draft permitting decision. The Department's response to these issues is as follows:

Comment #1

The first paragraph of the introduction on Page 5 should list the two fuel oil storage tanks as being 1.533 million gallons each, and the demineralized water storage tank should be listed as 1.35 million gallons. New calculations and emission tables have been included that reflect the change in tank size and corresponding change in VOC emissions.

Response to Comment #1

Agree. In addition to the requested change, Specific Condition #35, the Emission Summary Table, and Fee Calculation spreadsheet have been revised to reflect the decrease in permitted VOC emissions.

Comment #2

The table on page 7 correctly identifies the fuel oil PM₁₀ BACT determination as being filterable. However, filterable is not noted with the corresponding limit of 0.009 lb/MMBtu in the table on page 8 or the table on page 26. For the sake of clarity, and to avoid any confusion going forward, AECI requests that the notation (Filterable) be included with the fuel oil PM₁₀ BACT determination in the tables on pages 8 and 26.

Response to Comment #2

Agree. "Filterable" was inadvertently omitted. The draft permit has been revised.

Comment #3

The second to last sentence in the second paragraph of the Preliminary Analysis section on page 9 should not reference CO as a pollutant that requires no further consideration. CO was not required to undergo Class II Area Ambient Air Impact Analysis.

Response to Comment #3

Agree. PSD review was not triggered for CO, and it has been removed from the referenced sentence.

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

Comment #4

The Process Description at the bottom of page 11 should have the following deletions in order to be accurate. The word “TPS” should be removed from the first sentence. The “four cell wastewater cooling tower (SN-28 through SN-31)” should be removed from the second sentence.

Response to Comment #4

Agree. The requested revisions have been made.

Comment #5

The description on Page 19 for the Fuel Gas Water Bath Heater (SN-33) should list it as 12 MMBtu/hr, not 10 MMBtu/hr.

Response to Comment #5

Agree. The typographical error has been corrected.

Comment #6

Specific Condition #17 on page 29 states that the “Testing shall be performed within 180 days of issuance of Permit No. 1903-AOP-R7...” While this can be accommodated for the natural gas fuel type, construction for fuel oil combustion is not scheduled to be completed until the end of 2010. Assuming, for example, the final Permit is issued April 1st, this would require the completion of the specified testing by October 1st, by which time fuel oil combustion will not be possible. To avoid the necessity for submitting testing extension requests, AECI would request the language of this specific condition be modified to accommodate fuel oil testing within the allowed schedule for newly modified equipment. AECI proposes the following change be made to the language of the condition.

REPLACE:

Testing shall be performed within 180 day of issuance of Permit No. 1903-AOP-R7 in accordance with Plant Wide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A.

WITH:

For natural gas combustion, testing shall be performed within 180 day of issuance of Permit No. 1903-AOP-R7 in accordance with Plant Wide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A. For fuel oil fuel combustion, testing shall be performed

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source on fuel oil in accordance with Plant Wide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A.
Response to Comment #6

Agree. The requested change has been made.

Comment #7

AECI requests that additional language be appended to Specific Condition #19(c) on page 30 in order to clarify how operation during periods of startup, shutdown, and malfunction (SSM) are addressed with respect to complying with the applicable emission limits. NSPS Subpart 40 CFR 60.8(c) allows for an SSM exemption where it states the following (underlined portion):
“Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.” The Subpart KKKK rule is silent on SSM, therefore, those periods are exempt from the standard per Subpart A. AECI proposes to append the following sentence to the current specific condition.

Emissions during periods of startup, shutdown, and malfunction shall not be considered toward the calculation of excess emissions for this standard.

Response to Comment #7

Agree. The Air Division agrees to the requested change but also modifies the request to clarify that the exemption only applies to the standards listed in Specific Condition #19(a). Specific Condition #19(c) has been revised by appending the following:

Emissions during periods of startup, shutdown, and malfunction shall not be considered toward the calculation of excess emissions for the standards listed in Specific Condition #19(a).

Comment #8

Specific Condition #19(e) on page 31 references NSPS subpart KKKK in stating the initial compliance testing for NO_x and SO₂ requires testing at four points in the normal operating range of the turbines. This requirement seems to be a carry-over from the NSPS subpart GG requirement, which is no longer applicable, and is currently included in existing Permit No. 1903-AOP-R6. According to Subpart KKKK section 4400, the testing must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Further more, according to Subpart KKKK section 4405, facilities with NO_x-diluent CEMS may combine the initial

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

performance test with a standard RATA test. The testing is specified to be conducted at a single load level, within plus or minus 25 percent of 100 percent of peak load.

Also, the existing condition specifies that the initial test shall be conducted within 180 days after start-up. This time period has already elapsed for the natural gas fuel type, whose start-up was initiated in 2007. Therefore, AECI proposes the following replacement language for the existing condition to address both of these issues.

REPLACE:

Specific Condition #19(e)

WITH:

The permittee shall conduct an initial compliance test for NO_x and SO₂ within 180 days after start-up for fuel oil, and within 180 days of issuance of Permit No. 1903-AOP-R7 for natural gas. The testing shall be conducted for each fuel, at a single load level, within plus or minus 25 percent of 100 percent of peak load.

Response to Comment #8

There are two parts to this comment, and each part will be addressed separately. The first part mentions that Subpart KKKK specifies testing to be conducted at a single load level, within plus or minus 25 percent of 100 percent of peak load and that since the combustion turbines are equipped with CEMS the initial performance test may be combined with a standard RATA test pursuant to §60.4405. The Air Division agrees that Subpart GG and testing at four points in the normal operating range is no longer applicable. The draft permit has been revised.

The second part states that the time period has already elapsed for natural gas testing. The Air Division does not agree with that statement. AECI will be modifying the turbines and their control devices. Therefore, AECI must perform a test for natural gas and a test for fuel oil after the modifications have been completed. The initial test for NO_x may be combined with a standard RATA test as stated above.

Specific Condition #19(c) has been revised as follows:

The permittee shall conduct an initial compliance test for NO_x and SO₂ within 180 days after start-up for each fuel type. The testing shall be conducted for each fuel, at a single load level, within plus or minus 25 percent of 100 percent of peak load. [Regulation No. 19 §19.304, 40 CFR §60.8, and 40 CFR §60.4400 and §60.4415]

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

Comment #9

The Cooling Systems source description on page 37 should have “TPS Dell” replaced with “Dell” in paragraphs four and five.

Response to Comment #9

Agree. The draft permit has been revised.

Comment #10

The Fuel Oil Storage Tanks description on page 44 should list the capacity as 1,533,000 gallons instead of 1,750,000 gallons.

Response to Comment #10

Agree. The draft permit has been revised.

The US EPA Region 6 comments were sent via email on March 11, 2010. Below are the comments from the EPA and the Department’s responses to those comments:

EPA Comment #1

Page 4-2, Section 4.2, NO_x emissions calculation: Please explain the proposed use of “1,215,466 dscfm” as Peak Flue Gas Flow Rate.

“Peak Flue Gas Flow Rate” in Appendix A of both versions of the Applications (August 2009 and December 2009) was indicated as 924,843 scfm. (See page A-3) Please explain the discrepancy. Why has the Flue Gas Flow Rate in the calculation increased 131 % from that of August 2009 Application? With the flue gas flow rate increase, did the heat input capacity remain unchanged?

Response to EPA Comment #1

The peak flue gas rate of 1,214,466 dscfm is the sum total of a combustion turbine (924,843 dscfm) and a duct burner (290,623 dscfm) peak flue gas rate. The original application (August 2009) proposed No. 2 fuel oil combustion without duct firing. AECI – Dell later submitted a revised application (December 2009) which proposed to include duct firing. In both applications the heat input capacity of the turbines while combusting No. 2 fuel oil remained the same at 2,112 MMBtu/hr.

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

EPA Comment #2

Page 23, Specific Condition #2, it states, “Compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Conditions #3 through #18. Hourly emission rates are based on a worse-case fuel use scenario. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]” Please explain “ the worse-case fuel use scenario” and how the scenario and rates were derived?

Also, after checking with the listed citation below from Regulation No.18 §18.801, we did not find a correlation between this Specific Condition and referenced citations in the permit. Please explain.

“No person shall cause or permit the emission of air contaminants, including odors or water vapor and including an air contaminant whose emission is not otherwise prohibited by this Code, if the emission of the air contaminant constitutes air pollution.” (Regulation 18 §18.801)

Response to EPA Comment #2

For No. 2 fuel, oil the worst case fuel use is the maximum 15,190 gallons per hour with a heat content of 139 MMBtu/gal. This corresponds to a maximum heat input to the combustion turbines of 2,112 MMBtu/hr. The emission rates are based on AP-42 emission factors for fuel oil combustion (turbines) and natural gas combustion (duct burners) and the maximum heat input.

For natural gas, the worst case fuel use is the maximum 1.86 million standard cubic feet per hour of natural gas with a heat content of 1,020 MMBtu/MMscf. This corresponds to a maximum heat input of 1,898 MMBtu/hr heat input. The emission rates are based on AP-42 emission factors for natural gas combustion and the maximum heat input.

Specific Condition #2 contains a table listing the permitted non-criteria pollutants. Those pollutants are also air contaminants. The citation is the Department’s regulatory authority to limit the emissions of those pollutants.

EPA Comment #3

Page 25, Specific Condition #3, please clarify whether startup, shutdown, and malfunction (SSM) emissions were included in the determination for the PM₁₀ BACT emission limitation. BACT emission limits or conditions must be met on a continual basis at all levels of operation and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). Further, the emissions limits in the permit must be sufficient to demonstrate protection of short term ambient standards.

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

We are also concerned that the stated performance/compliance testing frequency does not ensure ongoing compliance with the BACT limits for PM₁₀ in Specific Condition #3. Has ADEQ considered the need to require more frequent PM₁₀ performance testing to help ensure ongoing compliance with the permit limits. Also, we would encourage ADEQ to work with the applicant to correlate its opacity monitoring with any performance testing for PM.

ADEQ should ensure that the periodic testing and monitoring requirement allow the source to demonstrate ongoing compliance, including during SSM conditions (See In the Matter of Citgo Refining and Chemicals, Order Responding to Petitions' Request, pp.6-7, Adm'r May 26, 2009) http://www.epa.gov/region07/air/title5/petitiondb/petitions/citgo_corpuschristi_west_response2007.pdf

Finally, DEQ should consider requiring the installation of PM CEMS for each Combustion Turbine/Duct Burner stack if such consideration has not already been made.

Response to EPA Comment #3

The BACT limits in the permit must be met at all times including periods of startup and shutdown. The Air Division requires periodic testing where CEMS are not installed, and the Air Division has determined for this facility that the testing frequency is sufficient to protect short-term emission limits.

The Air Division has considered the option requiring PM CEMS but does not see the need to install PM CEMS when there is no compelling regulatory requirement to do so and that periodic testing accomplishes the same determination of continuous compliance without additional cost to the facility.

EPA Comment #4

Page 25, Specific Condition #3, it states, "Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by the use of natural gas as a fuel and compliance with Specific Condition # 5 during combustion of fuel oil.

Source	Opacity Limit	Regulatory Citation
SN-01 and SN-02 (Natural Gas)	5%	Regulation 18 §18.501
SN-01 and SN-02 (No. 2 Fuel Oil)	10%	Regulation 19 §19.901

In the Specific Condition #5, it states, "The permittee will conduct daily observations while burning fuel oil by a person trained in EPA Reference Method 9 and keep a record of these observations..."

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

Neither requirement addresses opacity monitoring during SSM period when violations are most likely to occur. Regulation 18 requires "...limits the emissions of federally regulated air pollutants on a continuous basis." (Regulation No. 19, Definition of "Emission limitation" and "emission standard").

We recommend that ADEQ consider requiring the installation of a continuous opacity monitoring system (COMS) to measure and record the opacity of emissions from the two turbine generators.

Response to EPA Comment #4

The Air Division has considered the option of requiring COMS but there is no justification to install COMS when there is no compelling regulatory requirement to do so and that daily observation while burning No. 2 fuel oil accomplishes the same determination of continuous compliance.

The condition will remain unchanged.

EPA Comment #5

Page 38, Specific Conditions #39: it states, "The total dissolved solids concentration for SN-04 through SN-15 shall not exceed 8,000 parts per million in the water. "

ADEQ permitted total dissolved solids (TDS) concentration is 8000 ppm but tested actual TDS emission is in the range between 670 -730 ppm. (see Page 1-2, PSD Permit Application)

We question why ADEQ used emission factors from AP-42 and AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001 when a concentration based limit can be set utilizing recent test results. ADEQ should correct TDS concentration limit based on recent TDS test results in the Appendix F of the PSD Application.

AP-42 or other emission factors are helpful for estimating emission levels, they are generally not appropriate for determining compliance with an applicable requirement unless the factor has either been developed directly from the emission unit in question or substitutes for a proven mass-balance relationship. (See EPA Periodic Monitoring Guidance)

<http://www.epa.gov/region07/air/title5/t5memos/pmguide.pdf>

Response to EPA Comment #5

The Air Division does not require a permittee to take a lower emission limit when sampling indicates the concentrations to be lower than the limits in the permit. While the TDS

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

concentrations have been tested, emissions from the cooling towers have not. The use of AP-42 for PM emissions appears to be appropriate due to the lack of emissions testing. AWMA document was used because AP-42 is known to overestimate PM₁₀ emissions.

EPA Comment #6

Page 38, Specific Conditions #40: it states, “The total dissolved solids concentration for SN-16 through SN-22 and SN-24 through SN-27 shall not exceed 1,500 parts per million in the water. “

ADEQ should evaluate the TDS concentration limit based on recent TDS test results from the Appendix F of the PSD Application. (See comments made in Item 7)

Response to EPA Comment #6

See Response to EPA Comment #5.

EPA Comment #7

Page 38, Specific Condition #41: it states, “The permittee shall monitor monthly the total dissolved solids concentration to demonstrate compliance with Specific Condition # 39 and weekly to demonstrate compliance with Specific Condition # 40. The use of a hand held meter shall be considered as an acceptable compliance method provided that the permittee obtains prior approval from the ADEQ Stack Test Inspector Supervisor for the use of hand held meter and its calibration and maintenance protocol. Otherwise, the permittee shall demonstrate compliance by submitting samples to third party laboratories that use EPA accepted test methods for measuring the conductivity of the sample or TDS concentration.”

Upon submitting such request to ADEQ Stack Test Inspector Supervisor for the use of hand held meter, AECI should also notify EPA of the request for the change in test method.

Response to EPA Comment #7

Specific Condition #41 has been revised to state that the permittee shall provide a copy of the request to use an alternate compliance method.

EPA Comment #8

It does not appear that ADEQ addressed PM_{2.5} emissions in this permit action. It is unclear whether ADEQ is relying on the PM₁₀ surrogate to satisfy the PM_{2.5} requirements. If so, it is necessary to provide a demonstration to support the use of PM₁₀ as a surrogate for PM_{2.5}. See, e.g., 75 Fed. Reg. 6827, 6831-32 (February 11, 2010). ADEQ should evaluate whether to require the applicant to submit a revised application or demonstration addressing PM_{2.5}

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

emissions. *See, In re Louisville Gas and Electric*, Petition No. IV-2008-3 (Order on Petition). Additional information from the applicant should either address PM_{2.5} emissions directly or show how compliance with the PSD requirements for PM₁₀ will serve as an adequate surrogate for meeting the PSD requirements for PM_{2.5} in this specific permit, after considering and identifying any remaining technical difficulties with conducting an analysis of PM_{2.5} directly. The permit record must reflect a demonstration to support the use of PM₁₀ as a surrogate for PM_{2.5}. EPA headquarters is developing recommendations for carrying out a PM_{2.5} analysis using modeling and ambient monitoring data. In the meantime, we have worked with other permitting authorities and permit applicants to establish an appropriate PM_{2.5} modeling protocol. If the applicant chooses to address PM_{2.5} impacts directly, please contact us to develop a methodology that will ensure that an appropriate analysis is performed. Also, ADEQ should specify whether it is using its NO_x and SO₂ monitoring as a monitoring surrogate for PM_{2.5}. Although, we did note that the source is not required to monitor for SO₂ emissions through CEMS.

Response to EPA Comment #8

The permit does not address PM_{2.5} directly. PM_{2.5} New Source Regulations are not yet implemented by the state of Arkansas. As an "approved" state, the state has 3 years from the date of the rule to incorporate the provisions into its regulations. In the interim and in accordance with EPA policy, PM₁₀ remains as the surrogate pollutant. See October 24, 1997 memo from John Seitz, Director OAQPS, "Interim Implementation of New Source Review Requirements for PM_{2.5}" and later affirmed in "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5})", *Federal Register* /Vol. 73, No. 96 / Friday, May 16, 2008. ADEQ acknowledges that the EPA proposed a rule on February 11, 2010 to repeal the EPA 1997 policy for the use of PM₁₀ as a surrogate for PM_{2.5}. However, EPA has not yet made the rule final which would establish an effective date.

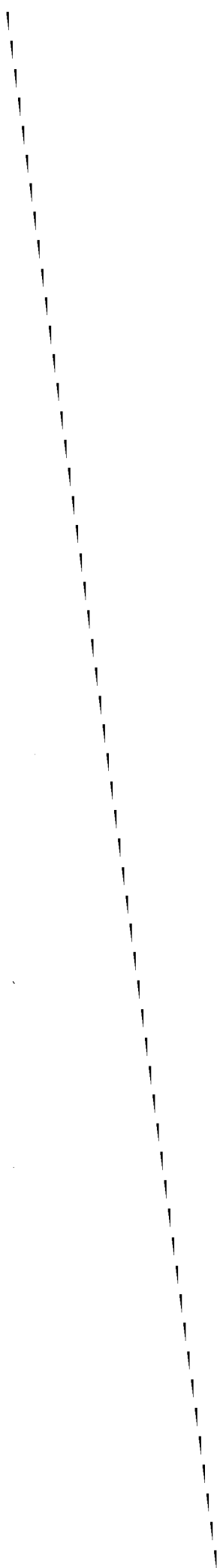
EPA Comment #9

On January 22, 2010, EPA signed a new National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO₂). The new standard is a 1-hour standard set at the level of 100 parts per billion (ppb). The effective date of the new NAAQS is April 12, 2010. The Department should evaluate its regulations to see if it is required to implement the new NAAQS as of April 12, 2010, should the permit not be issued prior to that date. Should the Department determine that the existing regulations provide for protection of any NAAQS in effect at the time of permit issuance (which would include the 1-hour NO₂ NAAQS beginning on April 12), then any permit issued on or after the effective date must contain a demonstration that the emissions increase from the proposed project does not cause or contribute to a violation of the new 1-hour NO₂ NAAQS. Since Arkansas regulations incorporate EPA's regulations at 52.21(k) by reference, EPA believes that Arkansas regulations should be interpreted to incorporate the new 1-hour NAAQS upon the effective date of that standard. See, 52 Fed. Reg. 24672, 24682 n. 9 (July 1, 1987).

Facility: AECI – Dell Power Plant
Permit No.: 1903-AOP-R7
AFIN: 47-00448

Response to Comment #9

It is anticipated that permit will be issued before April 12, 2010 which is the effective date for the new standard. The permittee has not been required to demonstrate compliance with the 1-hour NO₂ standard.





ARKANSAS
Department of Environmental Quality

March 31, 2010

Tadd Henry
Environmental Engineer
AECI - Dell Power Plant
301 E Hwy 18
Dell, AR 72426

Dear Mr. Henry:

The enclosed Permit No. 1903-AOP-R7 is issued pursuant to the Arkansas Operating Permit Program, Regulation # 26.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 1903-AOP-R7 for the construction, operation and maintenance of an air pollution control system for AECI - Dell Power Plant 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 8.603, within thirty (30) days after service of this decision.

All persons submitting written comments during the thirty (30) day, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. 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,

A handwritten signature in cursive script that reads "Mike Bates".

Mike Bates
Chief, Air Division

ADEQ OPERATING AIR PERMIT

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

Permit No. : 1903-AOP-R7

IS ISSUED TO:

AECI - Dell Power Plant
301 E. Hwy 18
Dell, AR 72426
Mississippi County
AFIN: 47-00448

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:

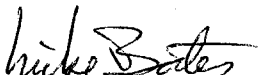
March 31, 2010

AND

March 30, 2015

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

Signed:


Mike Bates
Chief, Air Division

March 31, 2010
Date

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

Table of Contents

SECTION I: FACILITY INFORMATION 4

SECTION II: INTRODUCTION 5

Summary of Permit Activity 5

Process Description 11

Regulations 12

Emission Summary 13

SECTION III: PERMIT HISTORY 20

SECTION IV: SPECIFIC CONDITIONS 22

 SN-01 and SN-02 22

 SN-03 34

 SN-04 Through SN-22 and SN-24 Through SN-27 37

 SN-34 40

 SN-32 and SN-33 42

 SN-35 and SN-36 44

SECTION V: COMPLIANCE PLAN AND SCHEDULE 45

SECTION VI: PLANTWIDE CONDITIONS 46

 Acid Rain (Title IV) 47

 Title VI Provisions 47

SECTION VII: INSIGNIFICANT ACTIVITIES 49

SECTION VIII: GENERAL PROVISIONS 50

APPENDIX A

40 CFR Part 60, Subpart KKKK – *Standards of Performance for Stationary Gas Turbines*

APPENDIX B

40 CFR Part 60, Subpart Dc – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

APPENDIX C

40 CFR Part 63, Subpart YYYY – *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*

Appendix D

Clean Air Interstate Rule Permit

Appendix E

Fuel Monitoring Protocol

Appendix F

Continuous Emissions Monitoring Systems Conditions

Appendix G

Acid Rain Permit

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

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
NAAQS	National Ambient Air Quality Standard
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

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

SECTION I: FACILITY INFORMATION

PERMITTEE: AECI - Dell Power Plant

AFIN: 47-00448

PERMIT NUMBER: 1903-AOP-R7

FACILITY ADDRESS: 301 E. Hwy 18
Dell, AR 72426

MAILING ADDRESS: 301 E Hwy 18
Dell, AR 72426

COUNTY: Mississippi County

CONTACT NAME: Tadd Henry

CONTACT POSITION: Environmental Engineer

TELEPHONE NUMBER: 417-885-9222

REVIEWING ENGINEER: Charles Hurt, P.E.

UTM North South (Y): Zone 15: 3972883.78 m

UTM East West (X): Zone 15: 768626.70 m

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

SECTION II: INTRODUCTION

Summary of Permit Activity

Associated Electric Cooperative, Inc. – Dell Power Plant (AFIN: 47-00448) owns and operates a power plant located at 301 Highway 18 East in Dell, Arkansas 72426. AECI submitted a Title V renewal application with modifications. The permit modification includes firing No. 2 fuel oil for up to 1,850 hours per year and installing two 1.533 million gallon fuel oil storage tanks and one 1.35 million gallon demineralized water storage tank (not a source of air emissions). The emissions associated with the physical modifications are discussed later with the PSD applicability.

This modification also revises Specific Condition #27 (b) to account for the combustion process differences between operating on natural gas versus fuel oil. While burning natural gas the combustion turbines cycle through multiple staging modes prior to reaching full load premix operation. Whereas, liquid fuel is burned in a diffusion type flame without staging modes.

This modification also revises Specific Condition #41 to allow use of a handheld meter and to reduce the sampling frequency from weekly to monthly for total dissolved solids for SN-04 through SN-15. The use of the handheld meter will result in a significant reduction in time and cost in demonstrating compliance. Data accompanied the request which indicates compliance can be demonstrated with monthly sampling.

This modification also removes the waste water cooling tower (SN-28 through SN-31) and four (4.05 MMBtu/hr each) fuel gas heaters (insignificant activities) from the permit. The waste water cooling tower was never built, and AECI has no future plans to install the waste water cooling tower. The four fuel gas heaters do not exist. The only fuel gas heaters at the facility are SN-32 and SN-33.

Overall, the permitted increase was 84.5 tpy PM, 90.7 tpy PM₁₀, 6.64 tpy SO₂, 68.5 tpy CO, 98.3 tpy NO_x, and 0.21 tpy Lead. Permitted VOC decreased by 23.6 tpy.

Prevention of Significant Deterioration

This facility is considered an existing major source under 40 CFR §52.21, *Prevention of Significant Deterioration* (PSD) regulations because the facility is a fossil fuel fired steam electric plant and has the potential to emit more than 100 tpy of any single NSR pollutant. The following BACT analysis pertains to No. 2 fuel oil firing, and the limits for natural gas firing are not changing.

Modification PSD Applicability

The emission increase associated with the physical modifications is presented below and is based on past actual and future potential emissions. The past actual emissions are zero because the

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

combustion turbines have operated for less than two years. The future potential emissions are the potential to emit based on calculations submitted by the permittee.

Source	Emission Rate (tpy)					
	PM ₁₀	SO ₂	VOC	CO	NO _x	Lead
Combustion Turbine	33.21	2.97	6.18	49.04	48.33	0.03
Combustion Turbine	33.21	2.97	6.18	49.04	48.33	0.03
Diesel Storage Tank #1	-	-	1.02	-	-	-
Diesel Storage Tank #2	-	-	1.02	-	-	-
Total	66.42	5.94	14.40	98.08	96.66	0.06
PSD Significant Emission Rate	15	40	40	100	40	0.6
Is Netting Required?	Yes	No	No	No	Yes	No

No further consideration is given to SO₂, VOC, CO or Lead because the increase in the emission rates for those pollutants does not exceed significant emission rates (SER). Since the emission increase associated with the modification exceeds the SER for PM₁₀ and NO_x, the contemporaneous changes must be considered in determining whether or not PSD review is triggered. Only one contemporaneous change was identified during the contemporaneous period. On July 18, 2006 Permit No. 1903-AOP-R4 was issued to increase the hours of operation for the auxiliary boiler (SN-03) to 8,760 hours per year.

Source	Emission Rate (tpy)	
	PM ₁₀	NO _x
Auxiliary Boiler	2.71	17.82
Net Change	69.13	114.48
PSD Significant Emission Rate	15	40
Subject to PSD Review?	Yes	Yes

The net emission increase exceeded the PSD SER for PM₁₀ and NO_x. Therefore, PSD review was triggered for those pollutants.

BACT Analysis Summary

Any major source or major modification subject to PSD review must conduct an analysis to ensure the use of best available control technology (BACT). The requirements for conducting BACT can be found in the PSD regulations. A BACT analysis is required for each new or physically modified emission unit for each pollutant that exceeds an applicable PSD SER. For this modification PM₁₀ and NO_x exceed their respective SER. The emission units and pollutants that require BACT are listed below.

Emission Unit	Source Description	Pollutants Subject to BACT
SN-01	Combustion Turbine and HRSG	PM ₁₀ and NO _x
SN-02	Combustion Turbine and HRSG	PM ₁₀ and NO _x

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

The methodology used to determine BACT is the top-down method described in a 1987 memorandum from the EPA Assistant Administrator for Air and Radiation. Following the top-down method all available control technologies are ranked in descending order of control effectiveness. The most stringent control available for a similar or identical source or source category is identified, and a determination of feasibility is made. If the most stringent level of control is determined to be infeasible based on technical, economic, environmental, or energy related reasons, then the next most stringent option is evaluated. The process continues until the BACT level under consideration cannot be eliminated. The *New Source Review Workshop Manual (Draft)* lists the five basic steps of the method.

BACT Evaluation for the Combustion Turbines (SN-01 and SN-02)

Step 1. Identify All Control Technologies. - The following technologies were considered for the turbines:

Pollutant	Control Technology for Combustion Turbines
NO _x	Selective Catalytic Reduction (SCR)
	Selective Non-Catalytic Reduction (SNCR)
	Catalytic Absorption
	Catalytic Combustion
	Dry Low NO _x Burners (LNB)
	Water/Steam Injection
PM ₁₀ (Filterable)	Clean/Low Sulfur Fuels
	Good Combustion Practices (GCP)

Step 2. Eliminate Technically Infeasible Control Technologies - The second step is to determine which control technologies are infeasible for technical reasons. Each control technologies for each pollutant is considered, those that are clearly technically infeasible are eliminated.

Selective Non-Catalytic Reduction was determined to be infeasible because of the high gas velocity from the turbines (i.e. SNCR requires more residence time), and the reaction that results in lower NO_x concentrations occurs between 1600 °F and 2200 °F. The temperature of the exhaust gases are generally around 1300 °F. SNCR is not listed in the RACT/BACT/LAER Clearinghouse (RBLC) for large combustion turbines.

Catalytic Absorption and Catalytic Combustion were determined to be technically infeasible because those control technologies have not been demonstrated for large combustion turbines. Catalytic combustion control was attempted at one facility, Pastoria Energy, Bakersfield, CA but did not scale-up for the design requirements. It was replaced with SCR. Catalytic Absorption and Catalytic Combustion are not listed in the RBLC for large combustion turbines.

The technically feasible control technologies for NO_x are LNB, steam/water injection, and SCR, and the control technologies for PM₁₀ are all of the technologies listed above.

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

Step 3. Rank Remaining Control Technologies – The third step is to rank the remaining control technologies based on effectiveness.

For PM₁₀ both remaining control technologies will be employed. Therefore, ranking is not necessary for PM₁₀.

For NO_x all three remaining control technologies will be employed.

Step 4. Top Down Evaluation of Control Options - The fourth step is to evaluate the remaining control technologies based on economic, energy, and environmental considerations.

For PM₁₀ and NO_x the remaining control technologies will be employed. Therefore, evaluation of control options is not necessary for PM₁₀ or NO_x.

Step 5. Select BACT – The most effective control option not eliminated is BACT. Based on available information in the RACT/BACT/LAER Clearinghouse, publications from EPA's Clean Air, Technology Center, EPA's National Combustion Turbine Spreadsheet, and BACT determinations for oil fired combined cycle plants, BACT limits were determined to be:

Sources	Pollutant	BACT Determination ^(a)		
Each 7FA Combustion Turbine / HRSG with and without Duct Burners (SN-01 and SN-02) in No. 2 Fuel Oil Service	PM ₁₀ (Filterable)	Use of clean fuel ^(b) and good combustion practice ^(c)	0.009 lb/MMBtu	Stack Testing (3-hour average) and Fuel Monitoring
	NO _x	Dry Low NO _x Burners Water Injection SCR	6 ppmvd @15 % O ₂	3-hour average (CEMS)
	Visible Emissions	Use of clean fuel and good combustion practices	10%	Method 9 Observations

a. BACT Determination is valid only up to 1,850 hours per year per turbine on fuel oil.

b. Clean fuel is No. 2 fuel oil which contains 0.0015 percent by weight of sulfur or less.

c. "Good combustion practices" are taken to mean (1) the turbines shall be operated in a manner to achieve maximum thermal efficiency via operating only at high loads (e.g., greater than 60 percent of the power output capacity) to the extent possible, (2) the best available combustion fuel oil system for the existing turbines shall be installed and tuned properly to ensure complete (as possible) combustion.

Class II Area Ambient Air Impact Analysis

Air Quality Analysis

Since the total facility-wide emissions exceed the PSD SER for NO_x and PM₁₀ an air quality analysis is required to demonstrate that these emissions do not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or exceed a PSD increment. The air quality analysis consists of a preliminary analysis and where warranted a full impact analysis.

Preliminary Analysis

The preliminary analysis determines whether the applicant can forego further air quality analyses for a particular pollutant; may allow the applicant to be exempted from the ambient monitoring data requirements; and is used to define the impact area within which a full impact analysis must be carried out. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification.

For PSD permits, a full ambient air impact analysis is required for each pollutant from which the net emission increase will result in an ambient impact over the predetermined level. This level is known as the “significant impact level” (SIL). The following table shows the results of the preliminary analysis. A full impact analysis is not required for a particular pollutant when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels. Therefore, no further consideration is given to PM₁₀ (annual) and NO_x. A full impact analysis was required for 24-hour averaging period for PM₁₀.

Pollutant	Averaging Period	Year of Maximum Impact	Maximum Modeled Concentration (µg/m ³)	Significant impact Level (µg/m ³)
PM ₁₀	24-hour	2006	8.82	5
	Annual	2006	0.51	1
NO ₂	Annual	2008	0.91*	1

* The modeled concentration is based on the default ambient ratio NO₂/NO_x of 0.75.

Full Impact Analysis

A full impact analysis is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. The preliminary analysis above indicates a full impact analysis for the PM₁₀ 24-hour averaging period. Only the receptors with in the area of impact (AOI) are evaluated in the full impact analysis. Impacts exceeding the PM₁₀ 24-hour SIL extend out to 978 m. Therefore, the AOI was defined as circular area with a radius of 1 km.

The full impact analysis consists of a NAAQS analysis and increment consumption analysis. For the NAAQS analysis, emissions from the facility were based on the PTE. To estimate the total concentration, the modeled impacts from the facility and nearby facilities (inventory sources with in 50 km plus radius of impact) were added to the background concentration determined based on ambient monitoring data.

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

Pollutant	Averaging Period	Year of Maximum Impact	Modeled Concentration ^(a) ($\mu\text{g}/\text{m}^3$)	Total Concentration ^(b) ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)
PM ₁₀	24-hour	2004	16.79 ^(c)	80.79	150

- a. Modeled concentration is the impact from the source and inventory sources.
- b. Total concentration is the impact from the source, inventory sources, and the Little Rock PM₁₀ monitor.
- c. High 6th High 24-Hour modeled concentration

For the increment analysis the maximum 24-hour 2nd highest modeled impact is compared to the 24-hour increment. Regulation No. §19.904 (C)(1) requires further analysis if more than 80% of a short term increment is consumed. The table below indicates the modeled impacts are less than the increment and that no further analysis is required.

Pollutant	Averaging Period	Year of Maximum Impact	Modeled Concentration ^(a) ($\mu\text{g}/\text{m}^3$)	PSD Increment ($\mu\text{g}/\text{m}^3$)	80% of PSD Increment ($\mu\text{g}/\text{m}^3$)
PM ₁₀	24-hour	2008	17.97	39	31.2

- a. Modeled concentration is the impact from the source and inventory sources.

Class II Area Additional Impacts Analysis

An additional impact analysis is based 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, and (3) visibility impairment.

Growth Analysis

The growth analysis includes a projection of the associated industrial, commercial, and residential source growth that result in the area due to the source and an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth. The project is not expected to create any new fulltime positions. Residential growth is not expected to result from the project. In addition, the shipping of raw materials and products to and from the facility is not expected to significantly increase the level of rail or ground traffic in the area. Therefore, no appreciable increase in emissions is expected as a result of any industrial, commercial, or residential growth associated with the project.

Soils and Vegetation

The analysis of soil and vegetation air pollution impacts is based on an inventory of the soil and vegetation types found in the impact area. This inventory considers vegetation with commercial or recreational value. The Mississippi County area consists mainly of farmland. The primary crops present in the area include rice, sorghum, wheat, corn, cotton, and soybeans. The secondary NAAQS, which establish the ambient concentration levels below which no harmful effects to either soil or vegetation can be expected, are used as indicators of potentially adverse

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

impacts. Thus, the modeled impacts, all of which are below the applicable secondary NAAQS, presumptively show that there will be no adverse impact upon either soil or vegetation due to the proposed project.

Class II Area Visibility

A screening analysis of predicted impacts on visibility was performed. Visibility was evaluated using VISCREEN. The results from VISCREEN predicted that the light extinction and change in contrast were below the first level of screening (i.e. $\Delta E \leq 2.0$ and $C_p \leq 0.05$). Therefore, it is presumed the project will not have an adverse impact.

Class I Area Impact Analysis

Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. The nearest Class I area is the Mingo National Wildlife Refuge (NWR), which is approximately 120 km from the Dell Power Plant site.

A screening analysis of predicted impacts on Class I increments and visibility was performed. Visibility was evaluated using VISCREEN. The results from VISCREEN predicted that the light extinction and change in contrast were below the first level of screening (i.e. $\Delta E \leq 2.0$ and $C_p \leq 0.05$).

The Class I increment assessment was performed utilizing AERMOD analyses using a single-ring polar receptor grid, with receptors located at five-degree increments, 50 km from the center of the facility. The emissions associated with the proposed project for PM_{10} and NO_x were modeled and the results compared to the Class I SILs. As shown below, the modeling results are below the applicable Class I Increments and SILs for these pollutants. Therefore, it is presumed the project will not have an adverse impact on Class I increments.

	24-Hour PM_{10} ($\mu g/m^3$)	Annual PM_{10} ($\mu g/m^3$)	Annual NO_x ($\mu g/m^3$)
Maximum Impact	0.1889	0.0130	0.0086
Class I Area Increment	10	5	2.5
Class I Area SIL	0.3	0.2	0.1

Process Description

This facility is comprised of two GE S207FA combustion turbine-generators; two heat recovery steam generators (HRSG) configured for enhanced thermal efficiency; and steam turbine-generating equipment (SN-01 and SN-02). Additional emission generating equipment includes an auxiliary boiler (SN-03), an emergency generator (SN-23), a diesel fired fire pump (insignificant), a cooling tower system (SN-04 through SN-15), and an inlet cooling system (SN-16 through SN-27) consisting of three, four-cell mechanical draft cooling towers. In order to

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

reduce nitrogen oxide (NO_x) emissions for the facility and meet Arkansas emission guidelines, the facility utilizes Selective Catalytic Reduction (SCR) for the combustion turbine-generators.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
<i>Arkansas Air Pollution Control Code, Regulation 18, effective January 25, 2009</i>
<i>Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 18, 2009</i>
<i>Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective January 25, 2009</i>
<i>40 CFR Part 52.21 – Prevention of Significant Deterioration of Air Quality</i>
<i>40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</i>
<i>40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines</i>
<i>40 CFR Part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines</i>
<i>40 CFR Parts 72, 73, 75, and 76 - Acid Rain Program</i>
<i>40 CFR Part 97 - Clean Air Interstate Rule</i>
<i>40 CFR Part 82 - Stratospheric Ozone Protection</i>

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

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	104.3	392.4
		PM ₁₀	100.9	298.5
		SO ₂	9.7	42.1
		VOC	97.2	82.3
		CO	230.6	623.6
		NO _x	132.2	392.1
		Lead	0.31	0.51
HAPs*		1,3-Butadiene	0.09	0.11
		Acetaldehyde	0.17	0.81
		Acrolein	0.05	0.13
		Arsenic	0.07	0.09
		Benzene	0.26	0.44
		Beryllium	0.03	0.05
		Cadmium	0.03	0.05
		Chromium	0.07	0.09
		Cobalt	0.03	0.05
		Dichlorobenzene	0.03	0.05
		Ethyl benzene	0.14	0.60
		Formaldehyde	2.82	13.38
		Hexane	1.40	6.96
		Manganese	3.35	3.11
		Mercury	0.03	0.05
		Naphthalene	0.16	0.20
		Nickel	0.02	0.04
		PAH	0.17	0.21
		Phenanthrene	0.01	0.01
		POM	0.01	0.01
		Propylene oxide	0.12	0.50
		Selenium	0.11	0.13
		Toluene	0.62	2.24
		Xylene	0.41	1.21
Air Contaminants **		Ammonia	49.20	215.4

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-01	East Side Combustion Turbine/HRSG Stack (Natural Gas)	PM	32.0	140.2
		PM ₁₀	23.0	100.7
		SO ₂	4.0	17.5
		VOC	6.4	28.0
		CO	56.0	245.3
		NO _x	30.0	131.4
		Lead	0.10	0.10
		1,3-Butadiene	0.01	0.01
		Acetaldehyde	0.08	0.40
		Acrolein	0.02	0.06
		Ammonia	24.60	107.70***
		Arsenic	0.01	0.01
		Benzene	0.03	0.10
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.01	0.01
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Ethyl benzene	0.07	0.30
		Formaldehyde	1.40	6.10
		Hexane	0.60	2.60
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.02
		Nickel	0.01	0.01
		PAH	0.01	0.02
		Propylene oxide	0.06	0.25
		Selenium	0.01	0.01
		Toluene	0.30	1.10
		Xylene	0.20	0.60

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-01	East Side Combustion Turbine/HRSG Stack (No. 2 Fuel Oil)	PM	48.9	45.2
		PM ₁₀	48.9	45.2
		SO ₂	3.4	3.2
		VOC	11.6	10.7
		CO	53.1	49.1
		NO _x	52.3	48.4
		Lead	0.10	0.10
		1,3-Butadiene	0.04	0.04
		Ammonia	24.60	107.7***
		Arsenic	0.03	0.03
		Benzene	0.12	0.11
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.03	0.03
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Formaldehyde	0.62	0.57
		Hexane	0.57	0.53
		Manganese	1.67	1.54
		Mercury	0.01	0.01
		Naphthalene	0.07	0.07
		Nickel	0.01	0.01
		PAH	0.08	0.08
		Selenium	0.05	0.05
		Toluene	0.01	0.01

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-02	West Side Combustion Turbine/HRSG Stack (Natural Gas)	PM	32.0	140.2
		PM ₁₀	23.0	100.7
		SO ₂	4.0	17.5
		VOC	6.4	28.0
		CO	56.0	245.3
		NO _x	30.0	131.4
		Lead	0.10	0.10
		1,3-Butadiene	0.01	0.01
		Acetaldehyde	0.08	0.40
		Acrolein	0.02	0.06
		Ammonia	24.60	107.70***
		Arsenic	0.01	0.01
		Benzene	0.03	0.10
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.01	0.01
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Ethyl benzene	0.07	0.30
		Formaldehyde	1.40	6.10
		Hexane	0.60	2.60
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.02
		Nickel	0.01	0.01
		PAH	0.01	0.02
		Propylene oxide	0.06	0.25
		Selenium	0.01	0.01
		Toluene	0.30	1.10
		Xylene	0.20	0.60

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-02	West Side Combustion Turbine/HRSG Stack (No. 2 Fuel Oil)	PM	48.9	45.2
		PM ₁₀	48.9	45.2
		SO ₂	3.4	3.2
		VOC	11.6	10.7
		CO	53.1	49.1
		NO _x	52.3	48.4
		Lead	0.10	0.10
		1,3-Butadiene	0.04	0.04
		Ammonia	24.60	107.7***
		Arsenic	0.03	0.03
		Benzene	0.12	0.11
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.03	0.03
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Formaldehyde	0.62	0.57
		Hexane	0.57	0.53
		Manganese	1.67	1.54
		Mercury	0.01	0.01
		Naphthalene	0.07	0.07
		Nickel	0.01	0.01
		PAH	0.08	0.08
		Selenium	0.05	0.05
		Toluene	0.01	0.01

AECl - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-03	Auxiliary Boiler	PM	0.7	2.8
		PM ₁₀	0.7	2.8
		SO ₂	0.1	0.3
		VOC	0.5	2.0
		CO	6.9	30.0
		NO _x	4.1	17.9
		Lead	0.01	0.01
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.01	0.01
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Formaldehyde	0.01	0.03
		Hexane	0.20	0.70
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Phenanthrene	0.01	0.01
		POM	0.01	0.01
		Selenium	0.01	0.01
		Toluene	0.01	0.01
SN-04 through SN-15	12-Cell Cooling Tower	PM	3.9	16.9
		PM ₁₀	0.6	2.3
SN-16 through SN-22 and SN-24 through SN-27	Inlet Cooling System	PM	0.2	0.9
		PM ₁₀	0.1	0.6
SN-32	Fuel Gas Water Bath Heater (10 MMBtu/hr)	PM	0.1	0.4
		PM ₁₀	0.1	0.4
		SO ₂	0.1	0.1
		VOC	0.1	0.3
		CO	0.5	2.1
		NO _x	1.4	6.0

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-33	Fuel Gas Water Bath Heater (12 MMBtu/hr)	PM	0.1	0.4
		PM ₁₀	0.1	0.4
		SO ₂	0.1	0.1
		VOC	0.1	0.3
		CO	0.5	2.1
		NO _x	1.4	6.0
SN-34	500 Kilowatt Emergency Generator	PM	1.5	0.2
		PM ₁₀	1.5	0.2
		SO ₂	1.4	0.2
		VOC	1.7	0.3
		CO	4.5	0.6
		NO _x	20.7	2.6
		Lead	0.10	0.10
		1,3-Butadiene	0.01	0.01
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		PAH	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
SN-35	No. 2 Fuel Oil Storage Tank	VOC	35.8	1.0
SN-36	No. 2 Fuel Oil Storage Tank	VOC	35.8	1.0

*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.

*** Limit for both natural gas and fuel oil combustion.

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

SECTION III: PERMIT HISTORY

Permit #1903-AOP-R0 was issued on August 8, 2000, this was the initial Title V permit for GenPower - Dell. The permit introduced the installation of two GE turbines totaling 640 megawatts. GenPower underwent PSD review for the initial permit which is outlined below. As a part of the PSD review for GenPower, a Best Available Control Technology (BACT) analysis was required. The BACT analysis for GenPower considers emission controls for PM, PM₁₀, VOC, CO, and NO_x (SO₂ emissions were only 35.2 tpy).

BACT Summary

Source	Pollutant	BACT Determination		
Combustion Turbines with Duct Burners (SN-01 and SN-02)	PM/PM ₁₀	Clean fuel/Good combustion practices	0.021 lb/MMBtu	Natural Gas
	SO ₂	Combustion of low sulfur fuels	0.002 lb/MMBtu	Natural Gas
	CO	Good combustion practices and design	0.032 lb/MMBtu	Natural Gas
	VOC	Good combustion practices and design	0.0049 lb/MMBtu	Natural Gas
	NO _x	SCR and DLN combustion	(3.5 ppm at 0.015 lb/MMBtu)	Natural Gas
Auxiliary Boiler (SN-03)	PM/PM ₁₀	Clean fuel/Good combustion practices	0.010 lb/MMBtu	Natural Gas
	SO ₂	Combustion of low sulfur fuels	0.001 lb/MMBtu	Natural Gas
	CO	Good combustion practices and design	0.08 lb/MMBtu	Natural Gas
	VOC	Good combustion practices and design	0.005 lb/MMBtu	Natural Gas
	NO _x	Low NO _x Burner	0.04 lb/MMBtu	Natural Gas
Cooling Tower (SN-04 through SN-15)	PM/PM ₁₀	Drift Eliminators and Good Operating Practices	0.003% Drift from the water flow	-
Emergency Generator (SN-23)	PM/PM ₁₀ SO ₂ CO VOC NO _x	0.5% Sulfur Fuel and 250 hours/year usage	-	Diesel Fuel
Fire Pump Engine (Insignif.)	PM/PM ₁₀ SO ₂ CO VOC NO _x	0.5% Sulfur Fuel and 250 hours/year usage	-	Diesel Fuel

Permit #1903-AOP-R1 was issued on September 17, 2001. This modification was made to include ammonia emissions from the SCR. It also changed the name of the facility from Genpower - Dell, LLC to TPS - Dell, LLC.

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

Permit #1903-AOP-R2 was issued on May 1, 2002. This modification updated the calculations used to determine the emission rates from the cooling towers and added an inlet cooling system (SN-16 through SN-27) consisting of three four-cell mechanical draft cooling towers and a four cell wastewater cooling tower (SN-28 through SN-31). A suspension of construction extension was issued on December 20, 2004 that lasts until August 7, 2005.

Permit #1903-AOP-R3 was issued on August 15, 2005. This was the initial Title V permit renewal. The facility has a suspension of construction extension that expires on February 7, 2007. This permit modified the permitted HAP emissions based upon more representative emission factors and corrected the emissions from the wastewater cooling tower (SN-28 through SN-31). The changes resulted in increases of permitted emissions of PM by 3.3 tons per year (tpy) and HAPs by 9.21 tpy.

Permit #1903-AOP-R4 was issued on July 18, 2006. With this modification, the facility changed its name from TPS, Dell LLC to Associated Electric Cooperative, Inc. – Dell Power Plant. This modification also increased the permitted hours of operation of SN-03 from 1000 hours per year to 8760 hours per year. Permitted emissions increases from this change were 2.5 tpy PM/PM₁₀, 0.2 tpy SO₂, 1.8 tpy VOC, 27.0 tpy CO and 16.1 tpy NO_x.

The determination of BACT for SN-03 is based on it being a natural gas fired source. Controls were determined to be good combustion practices, low sulfur fuels, and low NO_x burners. Increasing the hours of operation did not affect the BACT limits as they are given as a lb/MMBtu emission rate. Also, the modeling/increment analysis were unaffected as they are based on hourly emission rates which were unchanged by this modification.

Permit No. 1903-AOP-R5 was issued on April 30, 2007. The modification added two fuel heaters to the permit as SN-32 and SN-33. Permitted emissions increased by 0.72 tpy PM/PM₁₀, 0.06 tpy SO₂, 0.52 tpy VOC, 4.02 tpy CO and 11.82 tpy NO_x.

Permit No. 1903-AOP-R6 was issued on May 19, 2008. The modification incorporated the applicable requirements of 40 CFR Part 96 Subparts AAAA-HHHH of the Clean Air Interstate Rule (CAIR) NO_x Ozone Season Trading Program. No new equipment or changes were proposed.

SECTION IV: SPECIFIC CONDITIONS

SN-01 and SN-02

Combustion Turbine Generators/Heat Recovery Steam Generators (HRSG) with Duct Burners

Source Description

The main emission sources of the facility are the two combustion turbine generators. These generators were supplied by General Electric, and are the GE Frame 7FA models, which operate in their combined cycle mode. These combustion turbines are limited to using natural gas as the primary fuel and No. 2 fuel oil for up to 1,850 hours per year. The GE Frame 7FA model combustion turbines incorporate lean pre-mix dry low NO_x combustors as well as the add-on Selective Catalytic Reduction (SCR) to minimize NO_x formation.

The turbine exhaust gas duct through a natural gas fired heat recovery steam generator (HRSG) where steam is produced and used by a steam turbine to generate additional electricity. Each HRSG is specifically designed to match the operating characteristics of the GE combustion turbines to provide optimum performance for the total power cycle. Each HRSG is a three-pressure, reheat, duct fired, natural circulation unit with a horizontal gas turbine exhaust flow receiver containing vertical heat tube transfer sections. Both HRSGs utilize duct firing at 100% load. Duct firing generates additional heat to the exhaust gases of the combustion turbines by burning natural gas. This heat energy is then converted to steam and electricity.

The primary consumer of the steam is a reheat, condensing steam turbine. It consists of a high-pressure section, which receives high-pressure superheated steam from the HRSGs and exhausts to the reheat section of the HRSG. The steam from the reheat section is then supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure section of the steam turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the condenser unit.

Emissions from the combustion gas turbine generator and the duct fired HRSG system will be exhausted through two stacks 165 feet above the ground surface. The combustion gas turbine generators shut down as necessary for scheduled maintenance, or as dictated by economic or electrical demand.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Conditions #3 through #18. Hourly emission rates are based on a worst-case fuel use scenario. [Regulation No. 19 §19.501 *et seq.*, Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

Source	Pollutant	lb/hr	tpy
SN-01 Natural Gas	PM ₁₀	23.0	100.7
	SO ₂	4.0	17.5
	VOC	6.4	28.0
	CO	56.0	245.3
	NO _x	30.0	131.4
	Lead	0.10	0.10
SN-01 No. 2 Fuel Oil	PM ₁₀	48.9	45.2
	SO ₂	3.4	3.2
	VOC	11.6	10.7
	CO	53.1	49.1
	NO _x	52.3	48.4
	Lead	0.10	0.10
SN-02 Natural Gas	PM ₁₀	23.0	100.7
	SO ₂	4.0	17.5
	VOC	6.4	28.0
	CO	56.0	245.3
	NO _x	30.0	131.4
	Lead	0.10	0.10
SN-02 No. 2 Fuel Oil	PM ₁₀	48.9	45.2
	SO ₂	3.4	3.2
	VOC	11.6	10.7
	CO	53.1	49.1
	NO _x	52.3	48.4
	Lead	0.10	0.10

- The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Conditions #3 through #18. Hourly emission rates are based on a worse-case fuel use scenario. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

Source	Pollutant	lb/hr	tpy
SN-01 Natural Gas	PM	32.0	140.2
	1,3-Butadiene	0.01	0.01
	Acetaldehyde	0.08	0.40
	Acrolein	0.02	0.06
	Ammonia	24.60	107.70
	Arsenic	0.01	0.01
	Benzene	0.03	0.10
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.01	0.01
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Ethyl benzene	0.07	0.30
	Formaldehyde	1.40	6.10
	Hexane	0.60	2.60
	Manganese	0.01	0.01
	Mercury	0.01	0.01
	Naphthalene	0.01	0.02
	Nickel	0.01	0.01
	PAH	0.01	0.02
	Propylene oxide	0.06	0.25
	Selenium	0.01	0.01
	Toluene	0.30	1.10
	Xylene	0.20	0.60
SN-01 No. 2 Fuel Oil	PM	48.9	45.2
	1,3-Butadiene	0.04	0.04
	Ammonia	24.60	107.70
	Arsenic	0.03	0.03
	Benzene	0.12	0.11
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.03	0.03
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Formaldehyde	0.62	0.57
	Hexane	0.57	0.53
	Manganese	1.67	1.54
	Mercury	0.01	0.01
	Naphthalene	0.07	0.07
	Nickel	0.01	0.01
	PAH	0.08	0.08
	Selenium	0.05	0.05
	Toluene	0.01	0.01

Source	Pollutant	lb/hr	tpy
SN-02 Natural Gas	PM	32.0	140.2
	1,3-Butadiene	0.01	0.01
	Acetaldehyde	0.08	0.40
	Acrolein	0.02	0.06
	Ammonia	24.60	107.70
	Arsenic	0.01	0.01
	Benzene	0.03	0.10
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.01	0.01
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Ethyl benzene	0.07	0.30
	Formaldehyde	1.40	6.10
	Hexane	0.60	2.60
	Manganese	0.01	0.01
	Mercury	0.01	0.01
	Naphthalene	0.01	0.02
	Nickel	0.01	0.01
	PAH	0.01	0.02
SN-02 No. 2 Fuel Oil	Propylene oxide	0.06	0.25
	Selenium	0.01	0.01
	Toluene	0.30	1.10
	Xylene	0.20	0.60
	PM	48.9	45.2
	1,3-Butadiene	0.04	0.04
	Ammonia	24.6	107.7
	Arsenic	0.03	0.03
	Benzene	0.12	0.11
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.03	0.03
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Formaldehyde	0.62	0.57
	Hexane	0.57	0.53
	Manganese	1.67	1.54
	Mercury	0.01	0.01
	Naphthalene	0.07	0.07
	Nickel	0.01	0.01
	PAH	0.08	0.08
	Selenium	0.05	0.05
	Toluene	0.01	0.01

- The permittee shall comply with the following BACT determinations for the two combustion turbine/heat recovery system generators. Compliance with the emission limits set forth in the following table shall be demonstrated by the initial performance test of each of the two stacks at the generators for each fuel type and every five years thereafter. [Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

Sources	Pollutant	BACT Determination		
Turbines In Natural Gas Service				
Each 7FA Combustion Turbine / HRSG with Duct Burners (SN-01 and SN-02)	PM ₁₀	Use of clean fuels and good combustion practice	0.021 lb/MMBtu	Stack Testing
	SO ₂	Use of low-sulfur fuel and good combustion practice	0.002 lb/MMBtu	Fuel Monitoring
	VOC	Use of clean fuels and good combustion practice	0.0049 lb/MMBtu	Stack Testing
	CO	Use of clean fuels and good combustion practice	0.032 lb/MMBtu	24-hour average (CEMS)
Each Combustion Turbine (with and without Duct Burner firing)	NO _x	Dry Low NO _x Combustors with SCR	3.5 ppmvd at 15% O ₂	3-hour average (CEMS)
Turbines In No. 2 Fuel Oil Service ^(a)				
Each 7FA Combustion Turbine / HRSG with and without Duct Burners (SN-01 and SN-02)	PM ₁₀ (Filterable)	Use of clean fuel ^(b) and good combustion practice ^(c)	0.009 lb/MMBtu	Stack Testing (3-hour average) and Fuel Monitoring
	NO _x	Dry Low NO _x Burners Water Injection SCR	6 ppmvd @ 15% O ₂	3-hour average (CEMS)
	Visible Emissions	Use of clean fuel and good combustion practice	10%	Method 9 Observations

a. BACT Determination is valid only up to 1,850 hours per year per turbine for fuel oil.

b. Clean fuel is No. 2 fuel oil which contains 0.0015 percent by weight or less of sulfur.

c. "Good combustion practices" are taken to mean (1) the turbines shall be operated in a manner to achieve maximum thermal efficiency via operating only at high loads (e.g., greater than 60 percent of the power output capacity) to the extent possible, (2) the best available combustion fuel oil system for the existing turbines shall be installed and tuned properly to ensure complete (as possible) combustion.

4. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by the use of natural gas as a fuel and compliance with Specific Condition #5 during combustion of fuel oil.

Source	Opacity Limit	Regulatory Citation
SN-01 and SN-02 (Natural Gas)	5%	Regulation 18 §18.501
SN-01 and SN-02 (No. 2 Fuel Oil)	10%	Regulation 19 §19.901

5. The permittee will conduct daily observations while burning fuel oil by a person trained in EPA Reference Method 9 and keep a record of these observations. If the permittee detects visible emissions in excess of the permitted limit, the permittee must immediately take action to identify and correct the cause of the excess visible emissions. After implementing the corrective action, the permittee must document the source complies with the visible emissions requirements. The permittee shall maintain records of the

cause of any visible emissions and the corrective action taken. The permittee must keep the records onsite and make the records available to Department personnel upon request. Each opacity record shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

6. The combustion turbine units may only fire pipeline natural gas or No. 2 fuel oil which contains 0.0015 percent by weight or less of sulfur. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
7. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #6. For natural gas, these records shall be a copy of the page or pages that contain the gas quality characteristics specified in either a purchase contract or pipeline transportation contract. For fuel oil, all receipts must be accompanied by supplier certifications stating that the concentration of sulfur is 0.0015 percent by weight or less. The records shall be kept on site, and shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]
8. Natural gas firing for the combustion turbine units shall be limited to a total of 39,500 million standard cubic feet per twelve consecutive months. The turbines may combust fuel oil for up to 1,850 hours per twelve consecutive months, each unit. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, 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 maintain monthly records which demonstrate compliance with Specific Condition #8. Records shall be updated by the fifteenth day of the month following the month to 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 total and each individual month's data shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

Testing and Monitoring Requirements

10. The permittee shall perform an initial stack test for each fuel type on each Combustion Turbine/HRSG with Duct Burner stack for PM and PM₁₀ to demonstrate compliance with the limits specified in Specific Conditions #1, #2, and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3. Testing shall be performed at 90% or above of the maximum operating load.
 - a. The PM test shall be performed using EPA Reference Methods 5 as found in 40 CFR Part 60, Appendix A.
 - b. The PM₁₀ test shall be performed by using either EPA Reference Method 201A or 5 as found in 40 CFR Part 60, Appendix A. By using Method 5, the facility will assume that all collected particulate is PM₁₀.

[Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

11. Monitoring requirements relative to SO₂ emissions from the Combustion Turbine/HRSG shall be as follows: [Regulation No. 19 §19.703, 40 CFR Part 52, Subpart E, 40 CFR Part 60, Subpart KKKK, 40 CFR Part 75, Subpart B, and A.C.A. §8- 4-203 as referenced by §8-4-304 and §8-4-311]
 - a. The permittee shall monitor the fuel sulfur content daily (unless an alternative monitoring plan is approved by the U.S. EPA).
 - b. The permittee shall conduct SO₂ emission monitoring procedures in accordance with Appendix D of 40 CFR Part 75. For natural gas, these procedures shall include: measuring pipeline natural gas fuel flow rate using an in-line fuel flow meter, determining the gross calorific value of the pipeline natural gas at least once per month, and using the default the emission rate of 0.0006 pounds of SO₂ per million Btu of heat input. For fuel oil, these procedures shall include flow proportional sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.
 - c. The permittee shall maintain records which demonstrate compliance with Specific Conditions #11(a) and (b).
12. The permittee shall perform a stack test on each Combustion Turbine/HRSG with Duct Burner stack for VOC for each fuel type to demonstrate compliance with the limits specified in Specific Conditions #1 and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3 and EPA Reference Method 25A as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
13. The permittee shall perform a stack test on each Combustion Turbine/HRSG with Duct Burner stack for CO for each fuel type to demonstrate compliance with the limits specified in Specific Conditions #1 and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3 and EPA Reference Method 10 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
14. The permittee shall install, calibrate, maintain, and operate a CO CEMS on each Combustion Turbine/Duct Burner stack. The measured concentration of CO and O₂ in the flue gas along with the measured fuel flow shall be used to calculate CO mass emissions. The CEMS shall be used to demonstrate compliance with the CO mass emission limits specified in Specific Condition #3. CO CEMS shall comply with the

ADEQ CEMS Conditions, see Appendix G. [Regulation No. 19 §19.703 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

15. The permittee shall perform a stack test on each Combustion Turbine/HRSG with Duct Burner stack for NO_x for each fuel type to demonstrate compliance with the limits specified in Specific Conditions #1 and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
16. Monitoring requirements relative to NO_x emissions from the Combustion Turbine/HRSG shall be as follows: [Regulation 19 §19.703, 40 CFR Part 52, Subpart E, 40 CFR Part 60, Subpart KKKK, 40 CFR Part 75, Subpart B, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
 - a. The permittee shall install, calibrate, maintain, and operate a NO_x CEMS on each Combustion Turbine/HRSG with Duct Burner stack. The CEMS shall comply with 40 CFR Part 75 and with ADEQ CEMS Conditions, see Appendix F. The permittee shall use the measured concentrations of NO_x and O₂ in the flue gas along with the measured fuel flow (or another 40 CFR Part 75 procedure) to calculate NO_x mass emissions. The CEMS shall be used to demonstrate compliance with the NO_x mass emission limits in Specific Condition #3.
 - b. The permittee shall monitor fuel nitrogen content (The permittee shall use the fuel monitoring protocol contained in Appendix E for natural gas).
 - c. The permittee shall maintain records which demonstrate compliance with Specific Condition #16(a).
17. The permittee shall perform a stack test for each fuel type on one of the Combustion Turbine/HRSG with Duct Burner stacks for 1, 3-butadiene, acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, PAH, propylene oxide, toluene, xylene, and ammonia, and to quantify other non-criteria pollutants not accounted for in this permit. This test will be used to demonstrate compliance with the limits specified in Specific Condition #2. For natural gas combustion, testing shall be performed within 180 day of issuance of Permit No. 1903-AOP-R7 in accordance with Plant Wide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A. For fuel oil fuel combustion, testing shall be performed within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source on fuel oil in accordance with Plant Wide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A. [Regulation No. 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

18. The permittee shall perform a stack test for each fuel type on one of the Combustion Turbine/HRSG with Duct Burner stacks for lead. This test will be used to demonstrate compliance with the limits specified in Specific Condition #2. Testing shall be performed every five years in accordance with Plant Wide Condition #3 and EPA Reference Method 12 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

NSPS Requirements

19. Due to the date of modification, the combustion turbines, heat recovery steam generators, and duct burners (SN-01 and SN-02) are affected sources under 40 CFR Part 60, Subpart KKKK - *Standards of Performance for Stationary Combustion Turbines*. The applicable requirements include but are not limited to the following:

- a. The permittee shall not discharge to the atmosphere any gases from SN-01 or SN-02 that contain the following pollutants in excess of the specified limits. Compliance with Specific Conditions #3 and #7 may be used to demonstrate compliance with these limits.

Pollutant	Emission Limit
SO ₂	0.06 lb/MMBtu
NO _x (natural gas)	15 ppm @ 15% O ₂
NO _x (fuel oil)	42 ppm @ 15%O ₂

- b. The permittee shall be exempted from monitoring sulfur content of the fuel under Subpart KKKK provided the permittee retains a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum total sulfur content for the fuel is 0.05 weight percent or less for fuel oil or 20 grains per 100 standard cubic feet or less for natural gas. Otherwise, the permittee shall monitor the total sulfur content in accordance with 40 CFR §60.4360. [Regulation No. 19 §19.304 and 40 CFR §60.4365]
- c. Excess emissions for NO_x is defined as any unit operating period in which the 4-hour or 30-day rolling average NO_x emission rate exceeds the emission limit in Specific Condition #19(a). The “4-hour rolling average NO_x emission rate” is the arithmetic average of the average NO_x emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_x emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_x emission rate is obtained for at least 3 of the 4 hours. The “30-day rolling average NO_x emission rate” is the arithmetic average of all hourly NO_x emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as

the average of all hourly NO_x emissions rates for the preceding 30 unit operating days if a valid NO_x emission rate is obtained for at least 75 percent of all operating hours. Emissions during periods of startup, shutdown, and malfunction shall not be considered toward the calculation of excess emissions for the standards listed in Specific Condition #19(a). [Regulation No. 19 §19.304 and 40 CFR §60.4380(b)(1)]

- d. Excess emissions for SO₂ is defined as each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine has the potential to exceed the limits in Specific Condition #19(a) and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. [Regulation No. 19 §19.304 and 40 CFR §60.4385]
 - e. The permittee shall conduct an initial compliance test for NO_x and SO₂ within 180 days after start-up for each fuel type. The testing shall be conducted for each fuel, at a single load level, within plus or minus 25 percent of 100 percent of peak load. [Regulation No. 19 §19.304, 40 CFR §60.8, and 40 CFR §60.4400 and §60.4415]
20. The following notifications to the Department are required for SN-01 and SN-02: (a) date of construction commenced postmarked no later than 30 days after such date, (b) anticipated date of initial startup between 30-60 days prior to such date, (c) actual date of initial startup postmarked within 15 days after such date, and (d) CEMS, opacity, and emissions performance testing 30 days prior to testing. [Regulation No. 19 §19.304 and 40 CFR §60.7(a)]

NESHAP Conditions

21. The permittee shall comply with the notification requirements of 40 CFR §63.6145 which include but are not limited to the following but need not comply with any other requirement of 40 CFR Part 63, Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register: [Regulation No. 19 §19.304 and 40 CFR §63.6095]
- a. The owner or operator must submit all of the notifications in §63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to the facility by the dates specified.
 - b. The owner or operator must submit an initial notification not later than 120 calendar days after becoming subject to the subpart.

Acid Rain Program

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

22. The Combustion Turbine and HRSG Duct Burner are subject to and shall comply with applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73 and 75). [Regulation No. 19 §19.304]
23. The submission of the NO_x, SO₂, and O₂ or CO₂ monitoring plans and notice of CEMS initial certification testing is required at least 45 days prior to the CEMS initial certification testing. [Regulation No. 19 §19.304 and 40 CFR Part 75 - Continuous Emission Monitoring Subpart G]
24. A monitoring plan is required to be submitted for NO_x, SO₂, and O₂ or CO₂ monitoring. [Regulation No. 19 §19.304 and 40 CFR Part 75 - Continuous Emission Monitoring Subpart G]
25. The initial NO_x, SO₂, and O₂ or CO₂ CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation. [Regulation No. 19 §19.304 and 40 CFR Part 75 Subpart A]
26. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times except during periods of calibration, quality assurance, preventative maintenance or repair, periods of backups of data from the data acquisition and handling system, or recertification. [Regulation No. 19 §19.304 and 40 CFR §75.10]
27. For the purposes of this permit, "upset condition" reports as required by §19.601 of Regulation 19 shall not be required for periods of startup or shutdown of SN-01 and SN-02. The record keeping requirements detailed below shall only apply for emissions which directly result from the start-up and/or shutdown of one or more of the combustion turbine units (SN-01 and SN-02). All other "upset conditions" must be reported as required by Regulation 19. The following conditions must be met during startup and shutdown periods.
 - a. All CEM systems required for SN-01 and SN-02 must be operating during start-up and shutdown. The emissions recorded during these periods shall count toward the annual ton per year emission limits.
 - b. The permittee shall maintain a log or equivalent electronic data record which shall indicate the date, start time, and duration of each start up and shut down event. For natural gas operation, "Startup" shall be defined as the period of time beginning with the first fire within the combustion turbine firing chamber until the units) are in "6" mode of operation. "Shutdown" shall be defined as the period of time having initiated the shut down event that the unit(s) drop below "6" mode of operation until fuel is no longer combusted in the firing chamber. Minute data that does not fall in the "6" mode of operation shall not be included in the hourly calculations for NO_x and CO rolling averages for the purpose of compliance with permit conditions. For fuel oil operation, "Startup" shall be defined as the period

of time beginning with the first fire within the combustion turbine firing chamber until the unit(s) reach normal operating mode with water injection and the SCR is operational. "Shutdown" shall be defined as the period of time having initiated the shut down event the unit(s) are outside of normal operating mode and the SCR is not operational until fuel is no longer combusted in the firing chamber. Minute data that does not fall in the "normal SCR operational" mode of operation shall not be included in the hourly calculations for NO_x and CO rolling averages for the purpose of compliance with the permit conditions. These logs or equivalent electronic data records shall be made available to Department personnel upon request.

- c. Opacity is not included. If any occurrences should ever occur, "upset condition" reporting is required.
- d. The facility shall comply with 40 CFR §60.7 reporting and recordkeeping requirements as applicable to NSPS limits and applicable parts of the ADEQ CEMS Conditions.

[Regulation 19, §19.601 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-03

Auxiliary Boiler

Source Description

One natural gas fired, low NO_x boiler, rated at 83 million BTU/hr, will be located on site to supply steam for startup use at the Dell facility. Steam from this boiler will maintain the operating temperatures of the HRSGs and steam turbine while the combustion turbines are off line. By maintaining operating temperatures the auxiliary boiler will reduce the time necessary to bring the combustion turbines on line. The auxiliary boiler will not be used to augment the power output of the facility during normal operating conditions.

Specific Conditions

28. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #32 through #35. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-03	PM ₁₀	0.7	2.8
	SO ₂	0.1	0.3
	VOC	0.5	2.0
	CO	6.9	30.0
	NO _x	4.1	17.9
	Lead	0.01	0.01

29. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated through compliance with Specific Condition #33. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-03	PM	0.7	2.8
	Arsenic	0.01	0.01
	Benzene	0.01	0.01
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.01	0.01
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Formaldehyde	0.01	0.03
	Hexane	0.20	0.70
	Manganese	0.01	0.01
	Mercury	0.01	0.01
	Naphthalene	0.01	0.01

AECI - Dell Power Plant
 Permit #: 1903-AOP-R7
 AFIN: 47-00448

Source	Pollutant	lb/hr	tpy
	Nickel	0.01	0.01
	Phenanthrene	0.01	0.01
	POM	0.01	0.01
	Selenium	0.01	0.01
	Toluene	0.01	0.01

30. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by the use of natural gas as a fuel.

Source	Opacity Limit	Regulatory Citation
SN-03	5%	Regulation 18 §18.501

31. The permittee shall comply with all applicable provisions of 40 CFR Part 60, Subpart A - General Provisions and Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. A copy of Subpart Dc is provided in Appendix C. Applicable provisions of Subpart Dc include, but are not limited to the following: [Regulation 19 §19.304 and 40 CFR Part 60, Subpart Dc]
- a. The owner or operator shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup. This notification shall include: [Regulation 19 §19.304 and §60.48c(a)]
 - i. The design heat input capacity of the boiler and identification of fuels to be combusted in the affected facility.
 - ii. The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired.
 - b. Records of the amounts of fuel combusted each month must be kept for SN-03. These records shall be kept on site for two years following the date of such records. [Regulation 19 §19.304 and §60.48c(g) and (i)]
32. The auxiliary boiler may only fire pipeline natural gas. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52 Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
33. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #32. These records shall be a copy of the page or pages that contain the gas quality characteristics specified in either a purchase contract or pipeline transportation contract. These records shall be kept on site and provided to Department personnel upon request. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

34. The permittee shall comply with the following BACT determinations for the auxiliary boiler. Compliance with the emission limits set forth in the following table shall be demonstrated by meeting the requirements of Specific Condition #33. [Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

Pollutant	BACT Determination	
PM/PM ₁₀	Clean fuel/Good combustion practices	0.010 lb/MMBtu
CO	Good combustion practices and design	0.08 lb/MMBtu
VOC	Good combustion practices and design	0.005 lb/MMBtu
NO _x	Low NO _x Burner	0.04 lb/MMBtu

35. The permittee shall perform an initial stack test on the auxiliary boiler (SN-03) for NO_x to demonstrate compliance with the limits specified in Specific Condition #34 Testing shall be performed in accordance with Plant Wide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

SN-04 Through SN-22 and SN-24 Through SN-27

Primary, Auxiliary, and Inlet Cooling Systems

Source Description

The power plant will employ a closed loop, non-contact cooling water system for the condenser cooling water and other equipment cooling needs. Large quantities of cooling water are required for removal of heat from the steam turbine condensers. Therefore, there are two cooling water systems associated with the Dell facility.

The “primary” cooling system (SN-04 through SN-15) incorporates a twelve cell mechanical draft cooling tower. This consists of a dedicated set of cooling water pumps and associated piping and controls to supply and retrieve water required to absorb excess heat generated by the combined cycle combustion turbines through the surface condenser.

Additional cooling water will be required to support the auxiliary and inlet cooling system (SN-16 through SN-22 and SN-24 through SN-27), which is a closed loop system to cool essential station equipment such as generator hydrogen coolers, turbine lube oil system coolers, and boiler feed pump and motor bearings. This auxiliary system is comprised of a three cell evaporative cooler, a four-cell inlet chiller, a dedicated set of circulating pumps, an expansion tank and piping. Makeup water for the condenser cooling water system, to replace water lost through evaporation and cooling tower drift, will be supplied from deep-well pumps. The water in this system will be treated to retard algae growth in the cooling towers.

Water treatment at the facility will consist of the demineralizer system and the chemical waste neutralization system. The steam generators will require very clean water for the steam generating system. The demineralizer provides high quality demineralized water for use as makeup to the HRSGs. This clean water will be provided from a small treatment plant consisting of demineralizing trains for removal of solids and other impurities; treatment to maintain pH; and treatment to remove dissolved oxygen. Dell will use automatic water analyzers and chemical feed stations to maintain the desired water quality in the condensate and steam systems.

Emissions from the cooling water system include evaporative emissions of particulate matter entrained in the cooling water. This system is not subject to 40 CFR Part 63, Subpart Q for National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers since Dell will use a non-chromate water treatment system.

Specific Conditions

36. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #39 through #42. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-04 - SN-15	PM ₁₀	0.6	2.3
SN-16 - SN-22 and SN-24 - SN-27	PM ₁₀	0.1	0.6

37. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #39 through #42. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-04 - SN-15	PM	3.9	16.9
SN-16 - SN-22 and SN-24 - SN-27	PM	0.2	0.9

38. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by Specific Conditions #41 and #42.

SN	Limit	Regulatory Citation
04 - 22 and 24 -27	20%	Regulation 18 §18.501

39. The total dissolved solids concentration for SN-04 through SN-15 shall not exceed 8,000 parts per million in the water. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]
40. The total dissolved solids concentration for SN-16 through SN-22 and SN-24 through SN-27 shall not exceed 1,500 parts per million in the water. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]
41. The permittee shall monitor monthly the total dissolved solids concentration to demonstrate compliance with Specific Condition #39, and weekly to demonstrate compliance with Specific Condition #40. The use of a hand held meter shall be considered as an acceptable compliance method provided that the permittee obtains prior approval from the ADEQ Stack Test Inspector Supervisor for the use of hand held meter and its calibration and maintenance protocol. A copy of the request which shall also be submitted to the EPA. Otherwise, the permittee shall demonstrate compliance by submitting samples to third party laboratories that use EPA accepted test methods for measuring the conductivity of the sample or TDS concentration. Measured TDS concentration and, if use of a hand held meter is approved, calibration records, shall kept on site and available for inspection. Records shall be updated by the 15th day of the month following the month to which the records pertain. Each individual TDS

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

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

42. The permittee shall comply with the following BACT determinations for the cooling towers. Compliance with the emission limit set forth in the following table shall be demonstrated by meeting the requirements of Specific Conditions #39 and #40. [Regulation 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

Pollutant	BACT Determination	
PM/PM ₁₀	Drift Eliminators and Good Operating Practices	0.0005% Drift from the water flow

SN-34

500 Kilowatt Emergency Generator

Source Description

One emergency generator will be installed to provide emergency power for maintaining plant control and critical systems operations during emergencies. The generator, rated at 500kW, will not be operated more than 250 hours per year, and is not intended to provide power for a black start.

Specific Conditions

43. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #45 through #50. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-34	PM ₁₀	1.5	0.2
	SO ₂	1.4	0.2
	VOC	1.7	0.3
	CO	4.5	0.6
	NO _x	20.7	2.6
	Lead	0.10	0.10

44. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #45, #46, #49, and #50. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-34	PM	1.5	0.2
	1,3-Butadiene	0.01	0.01
	Acetaldehyde	0.01	0.01
	Acrolein	0.01	0.01
	Benzene	0.01	0.01
	Formaldehyde	0.01	0.01
	Naphthalene	0.01	0.01
	PAH	0.01	0.01
	Toluene	0.01	0.01
	Xylene	0.01	0.01

45. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by Specific Condition #46.

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

SN	Limit	Regulatory Citation
34	20%	Regulation 18 §18.501

46. The permittee will conduct daily observations when the generator is operated more than 3 consecutive hours of the opacity from SN-34 by a person trained in EPA Reference Method 9 and keep a record of these observations. If the permittee detects visible emissions in excess of the permitted limit, the permittee must immediately take action to identify and correct the cause of the excess visible emissions. After implementing the corrective action, the permittee must document the source complies with the visible emissions requirements. The permittee shall maintain records of the cause of any visible emissions and the corrective action taken. The permittee must keep the records onsite and make the records available to Department personnel upon request. Each opacity record shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]
47. The emergency generator may only fire diesel fuel containing a maximum of 0.5% sulfur. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
48. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #47. Records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. Each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]
49. Operation of the emergency generator shall be limited to 250 hours per twelve consecutive months. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
50. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #49. Records shall be updated by the fifteenth day of the month following the month to 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 total and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

SN-32 and SN-33

Fuel Gas Water Bath Heaters

Source Description

These heaters are used to heat the fuel gas prior to combustion. SN-32 has a heat input of 10 MMBtu/hr and SN-33 has a heat input of 12 MMBtu/hr. These units are subject to 40 CFR Part 60, Subpart Dc.

Specific Conditions

51. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by burning only natural gas as a fuel. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-32	PM ₁₀	0.1	0.4
	SO ₂	0.1	0.1
	VOC	0.1	0.3
	CO	0.5	2.1
	NO _x	1.4	6.0
SN-33	PM ₁₀	0.1	0.4
	SO ₂	0.1	0.1
	VOC	0.1	0.3
	CO	0.5	2.1
	NO _x	1.4	6.0

52. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by burning only natural gas as fuel. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-32	PM	0.1	0.4
SN-33	PM	0.1	0.4

53. These source are considered affected sources under 40 CFR Part 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. Pursuant to §60.48c (g) and (i), records of the amounts of fuel combusted each month must be kept for SN-32 and SN-33. These records shall be kept on site for two years following the date of such records. [Regulation 19, §19.304 and 40 CFR §60.48c(g) and (i)]

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

54. Visible Emissions from these sources shall not exceed 5 percent opacity. Compliance shall be demonstrated by combusting only natural gas as fuel. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

SN-35 and SN-36

No. 2 Fuel Oil Storage Tanks

Source Description

The No. 2 storage tanks are fixed roof tanks, and each tank has a capacity of 1,533,000 gallons.

Specific Conditions

55. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is through compliance with Specific Condition #57. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-35	VOC	35.8	1.0
SN-36	VOC	35.8	1.0

56. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is demonstrated based on the maximum annual throughput. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]
57. The permittee shall not exceed a combined throughput of 257,380,000 gallons of fuel oil at SN-35 and SN-36 per consecutive twelve month period. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
58. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #57. Records shall be updated by the fifteenth day of the month following the month to 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 total and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

SECTION V: COMPLIANCE PLAN AND SCHEDULE

AECI - Dell Power Plant 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 A.C.A. §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) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) 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 A.C.A. §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 A.C.A. §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 A.C.A. §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 A.C.A. §8-4-304 and §8-4-311]

Acid Rain (Title IV)

7. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [Regulation 26, §26.701 and 40 CFR 70.6(a)(4)]

Clean Air Interstate Rule (CAIR) Provisions

8. The permittee will comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96. The permittee will comply with the NO_x emission requirements established under CAIR. The Permittee will report and maintain the records required by subpart HHHH of 40 CFR part 96. A copy of the CAIR permit is attached to this Title V permit. [Regulation No. 19 §19.1401 and 40 CFR Part 52, Subpart E]

Title VI Provisions

9. 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.
10. 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.
11. 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.
12. 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.
13. 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.

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

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 August 20, 2009.

Description	Category
Fire Pump – 1.82 MMBtu/hr	A-1
Diesel Storage Tank – 400 Gallon	A-3
Diesel Storage Tank – 500 Gallon	A-3

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 §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26)]
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)]

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

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 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 within thirty (30) days of 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 C.F.R. 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 Regulation 19, § 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 A.C.A. §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)]

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

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 within 30 days following the last day of the anniversary month of the initial Title V permit. 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 A.C.A. §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.

AECI - Dell Power Plant
Permit #: 1903-AOP-R7
AFIN: 47-00448

[Regulation 18, §18.314(A), Regulation 19, §19.416(A), Regulation 26, §26.1013(A), A.C.A. §8-4-203 as referenced by A.C.A. §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 A.C.A. §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 A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

APPENDIX A
40 CFR Part 60, Subpart KKKK – *Standards of Performance for Stationary Gas Turbines*

[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

Electronic Code of Federal Regulations

e-CFR

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e-CFR Data is current as of October 30, 2009

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

[Browse Previous](#)

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_x) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_x emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_x) and sulfur dioxide (SO₂).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NO_x)?

(a) You must meet the emission limits for NO_x specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_x.

§ 60.4325 What emission limits must I meet for NO_x if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO₂)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO₂ in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO₂ in excess of 65 ng SO₂/J (0.15 lb SO₂/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO₂ in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

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

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring**§ 60.4335 How do I demonstrate compliance for NO_x if I use water or steam injection?**

(a) If you are using water or steam injection to control NO_x emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_x monitor and a diluent gas (oxygen (O₂) or carbon dioxide (CO₂)) monitor, to determine the hourly NO_x emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NO_x if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_x emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance. If the NO_x emission result from the performance test is less than or equal to 75 percent of the NO_x emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§ 60.4335(b) and 60.4340, or

(2) Continuous parameter monitoring as follows:

- (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_x formation characteristics, and you must monitor these parameters continuously.
- (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_x mode.
- (iii) For any turbine that uses SCR to reduce NO_x emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.
- (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_x emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_x CEMS is chosen:

- (a) Each NO_x diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_x diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.
- (b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_x monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_x emission rate for the hour.
- (c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.
- (d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.
- (e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

- (a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).
- (b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm or lb/MMBtu, using the appropriate equation from

method 19 in appendix A of this part. For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂ (or the hourly average CO₂ concentration is less than 1.0 percent CO₂), a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_x concentrations to 15 percent O₂ is not allowed.

(d) If you have installed and certified a NO_x diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_x emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(\text{NO}_x)_h * (\text{HI})_h}{P} \quad (\text{Eq. 1})$$

Where:

E = hourly NO_x emission rate, in lb/MWh,

(NO_x)_h = hourly NO_x emission rate, in lb/MMBtu,

(HI)_h = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (P_e)_t + (P_e)_c + P_s + P_o \quad (\text{Eq. 2})$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(P_e)_t = electrical or mechanical energy output of the combustion turbine in MW,

(P_e)_c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_s = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Eq. 3})$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10_6$ = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(\text{NO}_x)_m}{\text{BL} * \text{AL}} \quad (\text{Eq. 4})$$

Where:

E = NO_x emission rate in lb/MWh,

(NO_x)_m = NO_x emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan must:

- (1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_x emission controls,
- (2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,
- (3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),
- (4) Describe quality assurance and control practices that are adequate to ensure the continuing validity

of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in § 75.19 or the NO_x emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input for units located in continental areas and 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO₂/J (0.42

lb SO₂/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input for continental areas or 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration

described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

- (i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.
- (ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.
- (iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.
- (iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

- (a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.
- (b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NO_x?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

- (a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_x control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

- (b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_x emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_x emission rate" is the arithmetic average of the average NO_x emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_x emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_x emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_x emission rate" is the arithmetic average

of all hourly NO_x emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_x emissions rates for the preceding 30 unit operating days if a valid NO_x emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, CO₂ or O₂ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_x emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO₂?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_x limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_x limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests**§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_x?**

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_x performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_x concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_x emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_x)_c * Q_{std}}{P} \quad (\text{Eq. 5})$$

Where:

E = NO_x emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

(NO_x)_c = average NO_x concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_x and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_x emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_x emission rate in lb/MWh.

(2) Sampling traverse points for NO_x and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in

EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_x and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_x concentrations is within ± 10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ± 5 ppm or ± 0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 24 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

(B) For turbines with a NO_x standard greater than 15 ppm @ 15% O_2 , you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ± 5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ± 3 ppm or ± 0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_x standard less than or equal to 15 ppm @ 15% O_2 , you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ± 2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ± 1 ppm or ± 0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_x with no additional post-combustion NO_x control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_x emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a

NOX-diluent CEMS?

If you elect to install and certify a NO_x-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

- (a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.
- (b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.
- (c) Use the test data both to demonstrate compliance with the applicable NO_x emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.
- (d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_x emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO₂ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228 D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO₂ concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO₂ emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_e * Q_{sd}}{P} \quad (\text{Eq. 6})$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(\text{SO}_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2 .

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/start means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_x emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than

enhancing the performance of the combustion turbine itself

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not selfpropelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit 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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO _x emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O ₂ or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O ₂ or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O ₂ or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O ₂ or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O ₂ or 700 ng/J of useful output (5.5 lb/MWh).

New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O ₂ or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O ₂ or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O ₂ or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O ₂ or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O ₂ or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O ₂ or 110 ng/J of useful output (0.86 lb/MWh).

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APPENDIX B

40 CFR Part 60, Subpart Dc – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

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Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

[Browse Previous](#) | [Browse Next](#)

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and 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 heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the 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 gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.41c 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 an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum 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 during a period of 12 consecutive calendar months.

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 derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

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 (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that 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 reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

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 SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(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 a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

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.

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 stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

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 (LP) 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 oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO₂ 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.

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.

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 for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as 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.

Wet flue gas desulfurization technology means an SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

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 SO₂.

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 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.42c Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the 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 combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the 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:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO₂ emissions limit or the 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO₂ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial 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 combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section.

Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3),

or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal 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 in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial 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 combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial 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 combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate or numerical SO₂ emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s = SO₂ emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2)

of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected 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 under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial 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 or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, 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 if the affected facility combusts only coal, or combusts coal with 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 with other fuels, 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.

(b) On and after the date on which the initial 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 wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30

MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial 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 can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility 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. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) 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, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater 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, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(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, whichever date comes first, 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 heat input capacity of 8.7 MW (30 MMBtu/hr) or greater 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, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO₂ emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. 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.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under §60.42c 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 the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO₂ emission limits under §60.42c is based on the average percent reduction and the average SO₂ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO₂ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average SO₂ emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} ($E_{ho,o}$) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} ($E_{ao,o}$). The $E_{ho,o}$ is computed using the following formula:

$$E_{ho,o} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{ho,o}$ = Adjusted E_{ho} , ng/J (lb/MMBtu);

E_{ho} = Hourly SO₂ emission rate, ng/J (lb/MMBtu);

E_w = SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 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. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO₂ emission limits under §60.42c pursuant to paragraphs (d) or (e) of

this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO₂ emission rate is computed using the following formula:

$$\%P_s = 100 \left(1 - \frac{\%R_f}{100} \right) \left(1 - \frac{\%R_g}{100} \right)$$

Where:

%P_s = Potential SO₂ emission rate, in percent;

%R_g = SO₂ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%R_f = SO₂ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the %P_s, an adjusted %R_g (%R_{g,o}) is computed from E_{ao} from paragraph (e)(1) of this section and an adjusted average SO₂ inlet rate (E_{ai,o}) using the following formula:

$$\%R_{g,o} = 100 \left(1 - \frac{E_w}{E_{ai,o}} \right)$$

Where:

%R_{g,o} = Adjusted %R_g, in percent;

E_{ao} = Adjusted E_{ao}, ng/J (lb/MMBtu); and

E_{ai,o} = Adjusted average SO₂ inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{ai,o}, an adjusted hourly SO₂ inlet rate (E_{hi,o}) is used. The E_{hi,o} is computed using the following formula:

$$E_{hi,o} = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

E_{hi,o} = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi} = Hourly SO₂ inlet rate, ng/J (lb/MMBtu);

E_w = SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by 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. The owner or operator does not have to measure E_w if the

owner or operator elects to assume $E_w = 0$; and

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating P_s and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating P_s or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) 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 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected 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 of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ± 14 °C (320 ± 25 °F).

(6) For determination of PM emissions, an oxygen (O₂) or carbon dioxide (CO₂) measurement shall be 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.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O₂ or CO₂ 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.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) 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 install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 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 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 (d) 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 paragraph (c)(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 (c)(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 (c)(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 O₂(or CO₂) 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) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in the Federal Register, whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O₂ (or CO₂), 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 on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main> or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243-01; RTP, NC 27711.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO₂ emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ control device is used), and shall

record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO₂ concentrations and either O₂ or CO₂ concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) 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) 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 subject to the percent reduction requirements under §60.42c, the span value of the SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according to the 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 SO₂ input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO₂ at the inlet or

outlet of the SO₂ 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 SO₂ and CO₂ measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 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 (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit 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.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the 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 in §60.43c(c) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install 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 §60.43c and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(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;

(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;

(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

(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 30 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 30 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 30 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) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO₂ or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) 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 §60.45c(c). The CEMS specified in paragraph §60.45c(c) 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.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) 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.

(ii) 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).

(iii) 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).

(iv) 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.

(2) 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.

(3) 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.

(4) You must record the CO measurements and calculations performed according to paragraph (e) 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.

(f) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and 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.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of 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 §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device 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 §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of §60.42c, or the

PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(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 (c)(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 (c)(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

(d) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO₂ emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO₂ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (O₂ or CO₂) 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 a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average

emission rates; justification for excluding data; and a description of corrective actions 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 the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO₂ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO₂ standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-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.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

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(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions.

(1) *Existing stationary combustion turbine.* A stationary combustion turbine is existing if you commenced construction or reconstruction of the stationary combustion turbine on or before January 14, 2003. A change in ownership of an existing stationary combustion turbine does not make that stationary combustion turbine a new or reconstructed stationary combustion turbine.

(2) *New stationary combustion turbine.* A stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

(3) *Reconstructed stationary combustion turbine.* A stationary combustion turbine is reconstructed if you meet the definition of reconstruction in §63.2 of subpart A of this part and reconstruction is commenced after January 14, 2003.

(b) *Subcategories with limited requirements.* (1) A new or reconstructed stationary combustion turbine located at a major source which meets either of the following criteria does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6145(d):

(i) The stationary combustion turbine is an emergency stationary combustion turbine; or

(ii) The stationary combustion turbine is located on the North Slope of Alaska.

(2) A stationary combustion turbine which burns landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified municipal solid waste (MSW) is used to generate 10 percent or more of the gross heat input on an annual basis does not have to meet the requirements of this subpart except for:

(i) The initial notification requirements of §63.6145(d); and

(ii) Additional monitoring and reporting requirements as provided in §63.6125(c) and §63.6150.

(3) An existing, new, or reconstructed stationary combustion turbine with a rated peak power output of less than 1.0 megawatt (MW) at International Organization for Standardization (ISO) standard day conditions, which is located at a major source, does not have to meet the requirements of this subpart and of subpart A of this part. This determination applies to the capacities of individual combustion turbines, whether or not an aggregated group of combustion turbines has a common add-on air pollution control device. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification. For example, a 0.75 MW emergency turbine would not have to submit an initial notification.

(4) Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

(5) Combustion turbine engine test cells/stands do not have to meet the requirements of this subpart but may have to meet the requirements of subpart A of this part if subject to another subpart. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification.

§ 63.6092 Are duct burners and waste heat recovery units covered by subpart YYY?

No, duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation.

§ 63.6095 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you start up a new or reconstructed stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion

turbine as defined by this subpart on or before March 5, 2004, you must comply with the emissions limitations and operating limitations in this subpart no later than March 5, 2004.

(2) If you start up a new or reconstructed stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart after March 5, 2004, you must comply with the emissions limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If your new or reconstructed stationary combustion turbine is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, it must be in compliance with any applicable requirements of this subpart when it becomes a major source.

(c) You must meet the notification requirements in §63.6145 according to the schedule in §63.6145 and in 40 CFR part 63, subpart A.

(d) *Stay of standards for gas-fired subcategories.* If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

[69 FR 10537, Mar. 5, 2004, as amended at 69 FR 51188, Aug. 18, 2004]

Emission and Operating Limitations

§ 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

General Compliance Requirements

§ 63.6105 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions.

(b) If you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

Testing and Initial Compliance Requirements

§ 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in §63.6095 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (b)(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.

§ 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

§ 63.6120 What performance tests and other procedures must I use?

- (a) You must conduct each performance test in Table 3 of this subpart that applies to you.
- (b) Each performance test must be conducted according to the requirements of the General Provisions at §63.7(e)(1) and under the specific conditions in Table 2 of this subpart.
- (c) Do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent.
- (d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.
- (e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.
- (f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (1) through (5) of this section.
 - (1) Identification of the specific parameters you propose to use as additional 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.
- (g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (1) through (5) of this section.

- (1) Identification of the parameters associated with operation of the stationary combustion turbine 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 why establishing limitations on the parameters is not possible;
- (4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;
- (5) For the parameters which could change in such a way as to increase HAP emissions, 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, unreasonable or unnecessary to adopt the parameters as operating limitations.

§ 63.6125 What are my monitor installation, operation, and maintenance requirements?

- (a) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you use an oxidation catalyst emission control device, you must monitor on a continuous basis your catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.
- (b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.
- (c) If you are operating a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 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 turbine in a manner which minimizes HAP emissions.
- (d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

§ 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

- (a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.
- (b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in § 63.6145(f).

Continuous Compliance Requirements

§ 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

§ 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of 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 § 63.6150.

(c) Consistent with §§ 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in accordance with § 63.6(e)(1)(i).

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

Notifications, Reports, and Records**§ 63.6145 What notifications must I submit and when?**

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

§ 63.6150 What reports must I submit and when?

(a) Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (a)(4) of this section. The semiannual compliance report must be submitted by the dates specified in paragraphs (b)(1) through (b)(5) of this section, unless the Administrator has approved a different schedule.

(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) For each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (a)(4)(iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in §63.6095 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 specified in §63.6095.

(2) The first semiannual 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 in §63.6095.

(3) Each subsequent semiannual 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) Each subsequent semiannual 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 combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual 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 (4) of this section.

(c) If you are operating as a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (c)(1) through (c)(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, digester gas, or gasified MSW 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.

(d) Dates of submittal for the annual report are provided in (d)(1) through (d)(5) of this section.

(1) The first annual report must cover the period beginning on the compliance date specified in §63.6095 and ending on December 31.

(2) The first annual report must be postmarked or delivered no later than January 31.

(3) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.

(4) Each subsequent annual report must be postmarked or delivered no later than January 31.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual 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 (d)(1) through (4) of this section.

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (e)(3) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(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.

§ 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (5).

(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 requirements in §63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in §63.10(b)(2)(vii).

(3) Records of the occurrence and duration of each startup, shutdown, or malfunction as required in §63.10(b)(2)(i).

(4) Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in §63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in §63.10(b)(iii).

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with

each operating limitation that applies to you.

§ 63.6160 In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection 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 retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

Other Requirements and Information

§ 63.6165 What parts of the General Provisions apply to me?

Table 7 of this subpart shows which parts of the General Provisions in §63.1 through 15 apply to you.

§ 63.6170 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 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 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA Administrator 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 emission limitations or operating limitations in §63.6100 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 to determine outlet formaldehyde concentration, as specified in §63.6110(b).

§ 63.6175 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; in 40 CFR 63.2, the General Provisions of this part; and in this section:

Area source means any stationary source of HAP that is not a major source as defined in this part.

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 reciprocating internal combustion engines.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101–549, 104 Stat. 2399).

Cogeneration cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger, such as a heat recovery steam generator.

Combined cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to generate steam for use in a steam turbine.

Combustion turbine engine test cells/stands means engine test cells/stands, as defined in subpart PPPPP of this part, that test stationary combustion turbines.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

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;
- (3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart; or
- (4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diffusion flame gas-fired stationary combustion turbine means:

- (1)(i) Each stationary combustion turbine which is equipped only to fire gas using diffusion flame technology,
 - (ii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, during any period when it is firing gas, and
 - (iii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.
- (2) Diffusion flame gas-fired stationary combustion turbines do not include:
- (i) Any emergency stationary combustion turbine,
 - (ii) Any stationary combustion turbine located on the North Slope of Alaska, or
 - (iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Diffusion flame oil-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Diffusion flame oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Diffusion flame technology means a configuration of a stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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 CO₂.

Distillate oil 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.

Emergency stationary combustion turbine means any stationary combustion turbine that operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency stationary combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary combustion turbines.

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 pollutant (HAP) means any air pollutant listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15 °C), 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 CO₂.

Lean premix gas-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Lean premix gas-fired stationary combustion turbines do not include:

- (i) Any emergency stationary combustion turbine,
- (ii) Any stationary combustion turbine located on the North Slope of Alaska, or
- (iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Lean premix oil-fired stationary combustion turbine means:

- (1)(i) Each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and
- (ii) Each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Lean premix oil-fired stationary combustion turbines do not include:

- (i) Any emergency stationary combustion turbine, or
- (ii) Any stationary combustion turbine located on the North Slope of Alaska.

Lean premix technology means a configuration of a stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber.

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 this section, 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 this section, 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 this standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Municipal solid waste as used in this subpart is as defined in §60.1465 of Subpart AAAA of 40 CFR Part 60, New Source Performance Standards for Small Municipal Waste Combustion Units.

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. May be field or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units.

and appurtenances, and equipment used transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Natural gas transmission and storage facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines. Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility.

North Slope of Alaska means the area north of the Arctic Circle (latitude 66.5 degrees North).

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 emission control device means an emission control device that incorporates catalytic oxidation to reduce CO emissions.

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.

Regenerative/recuperative cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to preheat the combustion air entering the combustion chamber of the stationary combustion turbine.

Research or laboratory facility means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a *de minimis* matter.

Simple cycle stationary combustion turbine means any stationary combustion turbine that does not recover heat from the stationary combustion turbine exhaust gases.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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.

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.

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

Table 1 to Subpart YYYY of Part 63—Emission Limitations

As stated in §63.6100, you must comply with the following emission limitations

For each new or reconstructed stationary combustion turbine described in §63.6100 which is . . .	You must meet the following emission limitations . . .
1. a lean premix gas-fired stationary combustion turbine as defined in this subpart, 2. a lean premix oil-fired stationary combustion turbine as defined in this subpart, 3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or 4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart.	limit the concentration of formaldehyde to 91 ppbvd or less at 15 percent O ₂ .

Table 2 to Subpart YYYY of Part 63—Operating Limitations

As stated in §§63.6100 and 63.6140, you must comply with the following operating limitations

For . . .	You must . . .
1. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst	maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
2. each stationary combustion turbine that is required to comply with the	maintain any operating limitations approved by the Administrator.

emission limitation for formaldehyde and is not using an oxidation catalyst	
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Table 3 to Subpart YYYYY of Part 63—Requirements for Performance Tests and Initial Compliance Demonstrations

As stated in §63.6120, you must comply with the following requirements for performance tests and initial compliance demonstrations

You must . . .	Using . . .	According to the following requirements . . .
a. demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on an annual basis AND	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348–03 provided that %R as determined in Annex A5 of ASTM D6348–03 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator	formaldehyde concentration must be corrected to 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1 hour runs. Test must be conducted within 10 percent of 100 percent load.
b. select the sampling port location and the number of traverse points AND	Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	if using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. determine the O ₂ concentration at the sampling port location AND	Method 3A or 3B of 40 CFR part 60, appendix A	measurements to determine O ₂ concentration must be made at the same time as the performance test.
d. determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	measurements to determine moisture content must be made at the same time as the performance test.

Table 4 to Subpart YYYYY of Part 63—Initial Compliance With Emission Limitations

As stated in §§63.6110 and 63.6130, you must comply with the following requirements to demonstrate initial compliance with emission limitations

For the . . .	You have demonstrated initial compliance if . . .
emission limitation for formaldehyde.	the average formaldehyde concentration meets the emission limitations specified in Table 1.

Table 5 to Subpart YYYY of Part 63—Continuous Compliance With Operating Limitations

As stated in §§63.6135 and 63.6140, you must comply with the following requirements to demonstrate continuing compliance with operating limitations:

For each stationary combustion turbine complying with the emission limitation for formaldehyde . .	You must demonstrate continuous compliance by . . .
1. with an oxidation catalyst	continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. without the use of an oxidation catalyst	continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

Table 6 to Subpart YYYY of Part 63—Requirements for Reports

As stated in §63.6150, you must comply with the following requirements for reports

If you own or operate a . . .	you must . . .	According to the following requirements . .
1. stationary combustion turbine which must comply with the formaldehyde emission limitation	report your compliance status	semiannually, according to the requirements of §63.6150.
2. stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis	report (1) 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, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters	annually, according to the requirements in §63.6150.
3. a lean premix gas-fired stationary combustion turbine or a diffusion	report (1) the number of hours distillate oil was fired by each new or existing stationary	annually, according to the requirements in

flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source	combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters	§63.6150.
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Table 7 of Subpart YYYY of Part 63—Applicability of General Provisions to Subpart YYYY

You must comply with the applicable General Provisions requirements:

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.1	General applicability of the General Provisions	Yes	Additional terms defined in §63.6175.
§63.2	Definitions	Yes	Additional terms defined in §63.6175.
§63.3	Units and abbreviations	Yes	
§63.4	Prohibited activities	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	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	Yes	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and	Yes	

			demonstrating compliance are specified at §§63.6135 and 63.6140.
§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.
§63.9(c)	Request for compliance extension	Yes	
§63.9(d)	Notification of special compliance requirements for new sources	Yes	
§63.9(e)	Notification of performance test	Yes	
§63.9(f)	Notification of visible emissions/opacity test	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	
§63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded	Yes	If alternative is in use.
§63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes	
§63.9(j)	Change in previous information	Yes	
§63.10(a)	Administrative provisions for recordkeeping and reporting	Yes	
§63.10(b)(1)	Record retention	Yes	
§63.10(b)(2)(i)–(iii)	Records related to SSM	Yes	
§63.10(b)(2)(iv)–(v)	Records related to actions during SSM	Yes	
§63.10(b)(2)(vi)–	CMS records	Yes	

(xi)			
§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 CMS	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 YYYYY does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No	Subpart YYYYY does not require reporting of startup, shutdowns, or malfunctions.
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYYY does not require COMS.
§63.10(e)(3)	Excess emissions and parameter exceedances reports	Yes	
§63.10(e)(4)	Reporting COMS data	No	Subpart YYYYY does not require COMS.
§63.10(f)	Waiver for recordkeeping and 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	

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Appendix D
Clean Air Interstate Rule Permit

each CAIR NO_x Ozone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of 40 CFR part 96 for such CAIR NO_x Ozone Season source and such CAIR NO_x Ozone Season unit.

(b) Monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96.

(2) The emissions measurements recorded and reported in accordance with subpart HHHH of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_x Ozone Season source with the CAIR NO_x Ozone Season emissions limitation under paragraph (c) of this §96.306.

(c) Nitrogen oxides ozone season emission requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_x Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NO_x Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this §96.306 starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3), or (7) and for each control period thereafter.

(3) A CAIR NO_x Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_x Ozone Season allowance was allocated.

(4) CAIR NO_x Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_x Ozone Season Allowance Tracking System accounts in accordance with subparts, FFFF, GGGG of 40 CFR part 96 and Chapter 14 of the Arkansas Pollution Control and Ecology Commission Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control.

(5) A CAIR NO_x Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_x Ozone Season Trading Program. No provision of the CAIR NO_x Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_x Ozone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFFF, GGGG of this part or Chapter 14 of the Arkansas Pollution Control and Ecology Commission Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, every allocation, transfer, or deduction of a CAIR NO_x Ozone Season allowance to or from a CAIR NO_x Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements.

(1) If a CAIR NO_x Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_x Ozone Season emissions limitation, then:

- (i) The owners and operators of the source and each CAIR NO_x Ozone Season unit at the source shall surrender the CAIR NO_x Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
- (ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.313 for the CAIR designated representative for the source and each CAIR NO_x Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.313 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHHH of 40 CFR part 96, provided that to the extent that subpart HHHH of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x Ozone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_x Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_x Ozone Season Trading Program.

(2) The CAIR designated representative of a CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall submit the reports required under the CAIR NO_x Ozone Season Trading Program, including those under subpart HHHH of 40 CFR part 96.

(f) Liability.

(1) Each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall meet the requirements of the CAIR NO_x Ozone Season Trading Program.

(2) Any provision of the CAIR NO_x Ozone Season Trading Program that applies to a CAIR NO_x Ozone Season source or the CAIR designated representative of a CAIR NO_x Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_x Ozone Season units at the source.

(3) Any provision of the CAIR NO_x Ozone Season Trading Program that applies to a CAIR NO_x Ozone Season unit or the CAIR designated representative of a CAIR NO_x Ozone Season unit shall also apply to the owners and operators of such unit.

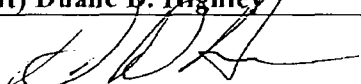
(g) *Effect on other authorities.*

No provision of the CAIR NO_x Ozone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x Ozone Season source or CAIR NO_x Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

3. CERTIFICATION

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

CAIR Designated Representative

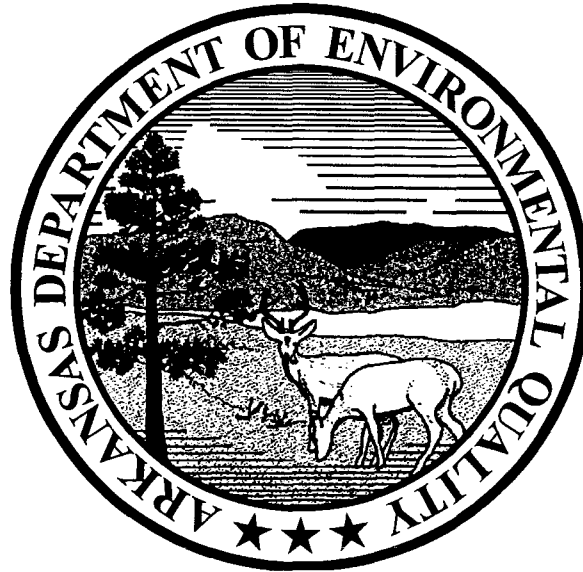
Name (Print) Duane D. Highley	
Signature 	Date 1-22-08

Appendix E
Fuel Monitoring Protocol

Fuel Monitoring Protocol for Stationary Turbines Subject to
40 CFR Part 60, Subpart KKKK

1. Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.
2. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The approved reference methods are: ASTM D1072 80; ASTM D3031 81; ASTM D3246 81; and ASTM D4084 82 as referenced in 40 CFR §60.335(b)(2). The Gas Processors Association (GPA) test method entitled "Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes" (GPA Standard 2377 86) is an approved alternative method.
3. The fuel supply shall be initially sampled daily for a period of two weeks to establish that the pipeline quality natural gas fuel supply is low in sulfur content.
4. After the monitoring required in item 3 above, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR §60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.
5. If after the monitoring required in item 4 above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR §60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.
6. Should any sulfur analysis as required in items 4 or 5 above indicate noncompliance with 40 CFR §60.333, the owner or operator shall notify the ADEQ of such excess emissions and the custom schedule shall be re examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re examined.
7. If there is a change in fuel supply (supplier), the fuel shall be sampled daily for a period of two weeks to re establish for the record that the fuel supply is low in sulfur content. If the fuel supply's low sulfur content is re-established, then the custom fuel monitoring schedule can be resumed.
8. Stationary gas turbines that use the same supply of pipeline quality natural gas to fuel multiple gas turbines may monitor the fuel sulfur content at a single common location.
9. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

Arkansas Department of Environmental Quality



CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

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 RATA, RAA, or 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

- 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

- 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 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. Except for Part 75 CEMs, 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. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.
- 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. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

- 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 % O ₂ or CO ₂
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 G
Acid Rain Permit

DELL POWER PLANT

Plant Name (from Step 1)

STEP 3**Read the
standard
requirements****Permit Requirements**

- (1) The designated representative of each affected source and each affected unit at the source shall:
 - (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
 - (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
- (2) The owners and operators of each affected source and each affected unit at the source shall:
 - (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
 - (ii) Have an Acid Rain Permit.

Monitoring Requirements

- (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

- (1) The owners and operators of each source and each affected unit at the source shall:
 - (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another affected unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
 - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 - (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
 - (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
- (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

**STEP 3,
Cont'd.**

Nitrogen Oxides Requirements The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

- (1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
- (2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
 - (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
 - (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

- (1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
 - (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 - (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 - (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
- (2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

- (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
- (2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
- (3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
- (4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

Plant Name (from Step 1)

DELL POWER PLANT

Step 3,
Cont'd.**Liability, Cont'd.**

- (5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
- (6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
- (7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

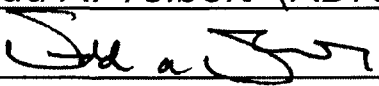
No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

- (1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
- (2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
- (3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
- (4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
- (5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4**Certification**

Read the
certification
statement,
sign, and
date

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Todd A. Tolbert (ADR)	
Signature		Date 11/18/2009

CERTIFICATE OF SERVICE

I, Pam Owen, hereby certify that a copy of this permit has been mailed by first class mail to
AECI - Dell Power Plant, 301 E Hwy 18, Dell, AR, 72426, on this 31st day
of march, 2010.

Pam Owen

Pam Owen, AAIL, Air Division

