ADEQ

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

September 15, 2009

Steven Anthony, Esq., President
Anthony Timberlands, Inc.
P.O. Box 137
Bearden, AR 71720

Dear Mr. Anthony:

The enclosed Permit No. 0456-AOP-R4 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. 0456-AOP-R4 for the construction, operation and maintenance of an air pollution control system for Anthony Timberlands, Inc. 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 this thirty (30) day period, 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.

Sincerely,

Mike Bates
Chief, Air Division

RESPONSE TO COMMENTS

Anthony Timberlands, Inc.
Permit No.: 0456-AOP-R4
AFIN: 52-00035

On June 3, 2009 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:

Correspondence from the facility received June 26, 2009:

Comment #1

In Specific Condition #1 for SN-22 the hourly limits for SO_2 and VOC should be 0.8 lb/hr and 0.5 lb/hr, respectively.

Response to Comment #1

Agree. The typographical error has been corrected.

Comment #2

In Specific Condition #2 for SN-02 and SN-03 the hourly limits for acrolein, benzene, and chlorine should be 0.23 lb/hr, 0.24 lb/hr, and 0.044 lb/hr, respectively.

Response to Comment #2

Agree. The typographical error has been corrected.

Comment #3

Specific Condition #5 prohibits any woodwaste other than southern yellow pine. The facility generates nearly all the woodwaste burned as fuel, and consists exclusively as southern yellow pine. However, a small percentage is brought in from area mills and may include hardwoods. Emissions are estimated from stack tests and AP-42 emission factors. AP-42 has a single set of emission factors for all species of wood. As such, Anthony requests that the southern yellow pine limitation be removed.

Response to Comment #3

The Air Division has reviewed the request and agrees to revise Specific Condition #5 to state the following:

> Wood residue shall be the only fuel combusted at SN-01, SN-02, SN-03, and SN-22 Wood residue is hogged wood, bark, sawdust, shavings, chips, mill rejects, sanderdust, or wood trim. [Regulation No. 19, §19.705, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

Facility: Anthony Timberlands, Inc.
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Comment #4

Specific Condition 7 requires monthly records of the type and weight of wood residue combusted (dry or wet), and to multiply the weight by 4,500 Btu/lb for green and wet wood residue and 8,000 Btu/lb for dry wood residue. At the Anthony facility, all wood residue is mixed in the fuel house and there is no metering device for feed to the boilers. So, it is literally impossible to calculate fuel usage in this manner. As an alternative, Anthony requests that the condition be revised to require records documenting hours of operation for each boiler and by documenting lumber dried. The maximum steam required was based upon the maximum lumber dried, and maximum emissions were based upon the worst case boilers (SN-02 and SN-03) being used 7,884 hours per year. So, limiting and documenting maximum lumber dried and maximum operating hours for the boilers should be an adequate demonstration of compliance with emission limits. Please note that the facility would be out of compliance immediately with the condition as it currently exists, so it is imperative that some alternative is considered.

Response to Comment #4

After further discussion with Mr. Breuer (ECCI) on behalf of Anthony Timberlands an acceptable alternative method of demonstrating compliance with Specific Condition #6 was proposed. In lieu of tracking the mass of fuel combusted by the boilers, Anthony proposed to track daily steam production. At least two other facilities in Arkansas (Deltic Timber, Waldo and Potlatch Prescott) demonstrate compliance with boiler emission limits via tracking steam production. Therefore, the Air Division agrees to replace Specific Conditions #6 and #7 with the following:

Specific Condition #6

The permittee shall comply with the following steam production limits. Compliance with this condition shall be demonstrated through compliance with Specific Condition #7. [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]

Source	Daily Steam Production limit (lb/day)	Annual Steam Production Limit (lb/year)
SN-01	496,800	1.813×10^8
SN-02	960,000	3.504×10^8
SN-03	960,000	3.504×10^8
SN-22	496,800	1.813×10^8

Specific Condition #7

The facility shall maintain monthly records that demonstrate compliance with the limits set in

Specific Condition #6 which may be used by the Department for enforcement purposes. These 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. An annual total and each individual month's steam production data shall be submitted to the Department in accordance with General Provision #7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

Comment #5

Specific Condition #13 requires stack testing of two boilers for PM_{10}, CO and NO_X within 180 days of the effective date of this permit and within three months prior to submittal of each Title V renewal application. The facility has stack tested on November 11, 2005 (CO and PM_{10}) for SN-02 and SN-03; October 23, 2007 (PM_{10}) for SN-03; and May 26, 2009 (PM_{10}) for SN-03. Due to the significant financial burden to conduct stack testing, Anthony requests that the Specific Condition #13 be revised to require stack testing only prior to renewal.

Response to Comment #5

The Air Division agrees to accept the results of the stack test conducted on May 26, 2009 (CAO LIS 09-015) as the first of at least two tests used to establish compliance with the PM_{10} emission limits SN-02 and SN-03, only. In regards to the CO and NO_X testing for all boilers and PM_{10} for SN-01 and SN-22, Anthony will continue with the test schedule as prescribed in Specific Condition #13.

Comment #6

Specific Condition #38, Specific Condition #39 and the Emission Summary refer to SN-16 as a Scotch Kiln. This should be revised to Irvington-Moore.

Response to Comment #6

The calculations, the emission summary, and emission rate tables of the application listed SN-16 as a "Scotch Kiln". The Air Division agrees to revise SN-16 to Irvington-Moore.

Comment #7

Plantwide Condition #7 requires the facility to prepare and implement a Startup, Shutdown and Malfunction Plan (SSM) per 40 CFR 63.6(e)(3). The facility has no sources subject to any emission limit in this subpart. As such, Anthony requests that this provision be removed from the permit.

Facility: Anthony Timberlands, Inc.
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Response to Comment #7

Agree. Plantwide Condition #7 was inadvertently included in the draft permit. The condition has been removed.

Comments Received from EPA

EPA Comment #1

Statement of Basis: Page 7 of 10, Section 12 Calculations: The source of Emission Factors for SN-12, 13, 14, 15, 16 and 25 are from ADEQ Factors.

Please explain how these emission factors were developed and provided the supporting data for these factors.

SN	Emission Factor Source	Emission Factor	Control Equipment	Control Equipment Efficiency	Comments
12, 13, 14, 15, 16, 25	ADEQ Factors	3.5 lb_{VOC}/MBF 0.016 lb_{For}/MBF 0.21 $lb_{methanol}$/MBF	None		Facility limited to 200 MMBF of lumber per any 12 consecutive months.

Response to EPA Comment #1

The emission factor source is NCASI Technical Bulletin No. 845. The statement of basis has been revised to clarify.

EPA Comment #2

Statement of Basis: Please clarify what is the emission factor of "0.016 lb_{For}/MBF"?

Response to EPA Comment #2

The "0.016 lb_{For}/MBF" is the emission factor for formaldehyde. The statement of basis has been revised to clarify.

EPA Comment #3

Statement of Basis: Page 7 of 10, Section 12 Calculations: ADEQ selected 0.21 lb/MBF as the emission factor for methanol, which differs from 0.265 lb/MBF recommended by NCASI. Please provide the data on ADEQ's emission factor.

Facility: Anthony Timberlands, Inc.
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Response to EPA Comment #3

The emission factor source is NCASI Technical Bulletin No. 845. The statement of basis has been revised to 0.265 lb/MBF. The revised emission factor is consistent with the calculations the applicant provided.

EPA Comment #4

Statement of Basis: Page 8 of 10, Section 13. TESTING REQUIREMETNS: [sic] Test interval for boilers is given once every five years. Explain why ADEQ believes that testing of one type of boiler per five years is an adequate test interval.

Response to EPA Comment #4

Testing once every five years is typical for other similar facilities. Specific Condition #13 of the permit requires testing one boiler of each size once every five years. Therefore, at least two boilers will be tested every five years (50% of each type of the boilers). The condition also requires annual testing when non-compliance is documented. Once the facility demonstrates compliance after two consecutive test then the test interval may be re-evaluated for less frequent testing.

EPA Comment #5

Had ADEQ required testing of each boiler every five years, this retroactive PSD should have been performed by 1999 instead 2009. Has ADEQ evaluated and/or file an enforcement action against ATI for PSD violations?

Response to EPA Comment #5

An interoffice memorandum regarding potential PSD violations was drafted and routed to the Air Division's Enforcement Branch on May 4, 2009.

EPA Comment #6

Following ADEQ's test schedule of "one type of boiler per five years", please explain:

1. Which of boilers have been tested so far; and
2. Which of these boilers has emission rates are calculated based on actual emission tests, and not strictly based on AP-42 factors?

Facility: Anthony Timberlands, Inc.
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Response to EPA Comment #6

1. To date only SN-03 has been tested according to the requirements proposed in the draft permit. PM_{10} testing at SN-03 was conducted on May 26, 2009 pursuant to a consent administrative order (CAO LIS 09-015, executed January 30, 2009). Anthony passed this test and will be required to retest by May 26, 2010. Of note, Anthony tested SN-03 for PM_{10} and CO in 2005, and PM_{10} 2007 with both test failed.

2. PM_{10} and CO are based on test limits for SN-02 and SN-03. NO_X, SO_2, VOC are based on AP-42 for SN-02 and SN-03. For SN-01 and SN-22 the limits are all based on AP-42. Draft Permit No. 456-AOP-R4 requires PM_{10}, CO, and NO_X emission limits to be verified by testing.

EPA Comment #7

Page 6, Basis for PSD Review: Kilns Project and Planer Mill #2 Project: Please list the proposed BACT limits in both numeric limits and production limits. The numeric BACT limits should include lb/hr and tpy (indicating averaging time).

Response to EPA Comment #7

The Air Division agrees to revise the section of the draft permit referenced above to include:

Kiln Project – Therefore, BACT for this project is "no control" and hourly and ton per year limits are based on a production limit of 3.5 lb VOC per thousand board feet. The hourly and annual limits are 36.75 lb VOC/hr (3-hour average) and for SN-14 and SN-15, 12.25 lb VOC/hr for SN-16, and 350 tpy VOC for all kilns.

Planer Mill Project - Therefore, BACT for this project is "no control" and hourly and ton per year limits are based on a production limit of 0.01 lb PM_{10} per ton woodwaste. The hourly and annual limits are 0.2 lb PM_{10}/hr (3-hour average) and 0.3 tpy PM_{10}.

The draft permit has been revised to include these clarifications.

EPA Comment #8

The EPA commented on the sequence of the sources listed on in the heading on Page 17 of the draft.

Response to EPA Comment #8

There is indeed a typographical error. The correct sequence should be SN-01, SN-02, SN-03,

and SN-22. The draft has been revised.

EPA Comment #9

Page 17, Specific Condition #1: Please explain which of those hourly emission rates are based on heat input capacity and AP-42 emission factors rather than based on actual emission factors from the test results?

As stated in the draft permit that the AP-42 emission factors proved to significantly underestimate actual emissions for SN-03, why did ADEQ not use the actual emission factors to calculate hourly emission rate.

Response to EPA Comment #9

The hourly emission rates for SN-02 and SN-03 are based on testing conducted in 2007 for PM_{10} and testing at SN-03 conducted in 2005 for CO. SN-03 was tested and accepted for both SN-02 and SN-03 which are of same make and size. The hourly emission rate for all other boilers and pollutants are based on AP-42 emission factors. Anthony has not been required to test in the past. Thus, data does not exist for establishing emission limits based on actual emissions except for PM_{10} and CO for SN-03.

EPA Comment #10

Page 17, Specific Condition #1: it states,

> Compliance with the annual limits shall be demonstrated through compliance with Specific Condition #6. For CO compliance with the annual limit shall be demonstrated through compliance with Specific Conditions #6 and #8. [Regulation 19, §19.501 *et seq.*, and 40 CFR Part 52, Subpart E]

Condition #6 states:

> The permittee shall not exceed 1,000,000 MMBtu (10^{12} British thermal units) of heat input per consecutive 12-month period for SN-01, SN-02, SN-03, and SN-22, combined.

Neither condition (#6 and #8) requires ATI to comply with hourly emission rates, please explain. While ATI may comply with annual production limits, there is no monitoring and/or data requirements which can demonstrate ATI's compliance with hourly emission rates. Please explain whether ATI can demonstrate compliance with an hourly emission rate.

Response to EPA Comment #10

Specific Condition #1 in its entirety states:

> The permittee shall not exceed the emission rates set forth in the following table. The hourly pollutant emission rates are based on the heat input capacity and AP-42 emission factors except where required to test. Compliance with the annual limits shall be demonstrated through compliance with Specific Condition #6. For CO compliance with the annual limit shall be demonstrated through compliance with Specific Conditions #6 and #8. [Regulation 19, §19.501 *et seq.*, and 40 CFR Part 52, Subpart E]

Therefore, compliance with hourly limits is demonstrated through testing for PM_{10}, CO, and NO_X and AP-42 for SO_2 and VOC. Compliance with annual limits is demonstrated through monthly recordkeeping (SC#6 and SC#8). Also, note that Specific Condition #6 was replaced in response to comments from the permittee (Comment #4) with more frequent monitoring and data requirement and is typical of other similar facilities in Arkansas.

EPA Comment #11

Page 19, Specific Condition #4, it states,

> SN-01, SN-02, SN-03 and SN-22 are subject to the Compliance Assurance Monitoring (CAM) Rule and shall comply with all applicable provisions, including but not limited to: [Regulation 19, §19.304 and 40 CFR Part 64]

Please state the pollutants which are required to comply with CAM Rule.

Response to EPA Comment #11

Multiclones are the only control devices associated with the boilers. These control devices provide control for particulate matter, only. Therefore, particulate matter is the only pollutant emitted from the boilers which is required to comply with 40 CFR Part 64 – Compliance Assurance Monitoring.

EPA Comment #12

Page 19, Specific Condition #4, it states,

> Daily observations of the opacity from each source shall be conducted by personnel familiar with the permittee's visible emissions.

Please specify that the personnel who performs the opacity observation must be trained according to the procedures stated in Method 9 and be certified before performing the test. (CFR Part 60, Appendix A–4 to Part 60—Test Methods 6 through 10B)

The same comment also applies to the opacity monitoring requirement for these emission sources.

Page	SN	Source
19	SN-01, SN-02, SN-04, SN-22	Boilers
22	SN-04	Small Log Mill Chipper
24	SN-05	Chip Bin
26	SN-06	Sawdust Bin
28	SN-07	Planer Shavings Cyclone
30	SN-09	Planer Shavings Cyclone
32	SN-11	Planer Shavings Cyclone
38	SN-25	Planer Mill #2

Response to EPA Comment #12

The affected specific conditions are #4, #17, #21, #25, #29, #33, #37, and #50. These conditions have been revised to require personnel conducting opacity reading for the sources listed above to be trained in EPA Reference Method 9 and certified.

EPA Comment #13

Draft Permit, Page 20, Specific condition #7: it states,

> The permittee may elect to have an independent lab determine the heat content of wet or dry wood residue for samples of fuel obtained at the facility.

If ATI uses in-house personnel to perform this enforceable element, ADEQ should specify the analytical methods that ATI should use to conduct the determination and the recordkeeping requirement.

Besides, ADEQ should audit ATI's lab and make sure that lab personnel have been properly trained, and that the laboratory has sound quality assurance and quality control procedures in written.

Determination of heat content affects calculation of heat input limit of the boiler and verification of yearly total heat input limitation set in the TV Permit. For the purpose of impartiality, this job should be performed by an outside laboratory.

Facility: Anthony Timberlands, Inc.
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Response to EPA Comment #13

Specific Condition #7 was revised pursuant to comments from the permit (Comment #4). Therefore, this comment is no longer relevant.

EPA Comment #14

Page 22, 1st paragraph: it states,

> The small log mill chipper employs a cyclone to control particulate matter emissions. The cyclone is assumed to have a control efficiency of 95%.

Assumed efficiency value should be used only when actual efficiency is not available for new equipment and should be verified by stack test later as stated in Plantwide Condition #3. (See below).

ATI claimed that stack test of a similar cyclone was done in 1992 at another ATI's plant and indicated a higher efficiency of 99.99%. However, that test was done 10 years ago at another plant with different cyclone. Efficiency may decrease with the age of the equipment. Please explain how the source can demonstrated ongoing compliance without periodic testing requirements, or why testing is not technically feasible.

> 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]" (Plantwide Conditions #3, Page 42 of the Draft Permit)

Same comment also applies for other cyclones listed below with assumed control efficiency of 95%. Has ADEQ placed each of these cyclones on a test schedule?

SN-04	Small Log Mill Chipper
SN-05	Chip Bin
SN-06	Sawdust Bin

SN-07	Planer Shavings Cyclone
SN-09	Planer Shavings Cyclone (Green Fuel Storage)
SN-11	Planer Shavings Cyclone

Response to EPA Comment #14

Not all sources new, newly modified, or operating are scheduled to be tested. Unless testing is required by law or federal requirement, a source might not be required to test. There are no source or pollutant applicable NSPS or MACT requirements. For these sources testing may be feasible. However, testing was not proposed when considering six existing sources collectively only emit a half ton per year of PM_{10}.

EPA Comment #15

The monitoring requirements are inadequate to assure compliance because the permit does not require the monitoring for opacity to occur at particular times - specifically, when "violations are most likely to occur, such as during startup and shut down operations." The applicable requirement contains no periodic monitoring, permitting authorities must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." [40 C.F.R. § 70.6(a)(3)(i)(B)]

Response to EPA Comment #15

Specific Conditions # 4, #17, #21, #25, #29, #33, #37, and #50 were revised to include observations during periods when violations are most likely to occur.

EPA Comment #16

Page 2, 3rd paragraph, PSD Review – Title V Permitting History: It states the ATI submitted to ADEQ two PSD analysis reports VOC BACT emission limits on April 10, 2008 and PM_{10} BACT emission on October 5, 2007. EPA has no recollection of receiving these documents. This review on the BACT analysis is based on limited information presented in the above stated application.

Due to deficiency of adequate permit information for review, EPA reserves the right to reject or to revoke this permit in the future if new information proves otherwise of that which is present in these documents.

Response to EPA Comment #16

This comment is general and does not specify what the deficiencies maybe. Even though the EPA may not have received the documents referenced above, the application dated December

2008 did contain sufficient information to review the BACT analysis for the two retroactive PSD projects.

EPA Comment #17

Page 6, Kiln BACT Analysis: ATI proposed VOC BACT limit of 350 tpy based on 3500 lb/MMBF. Please express BACT limit using lb/hr and indicating averaging time.

Response to EPA Comment #17

This comment is the same as EPA Comment #7. See Response to EPA Comment #7.

EPA Comment #18

Page 3, PLANER MILL CYCLONE (SN-25) BACT ANALYSIS: Please state the proposed PM_{10} BACT limit in lb/hr and tpy (with averaging time).

Response to EPA Comment #18

This comment is the same as EPA Comment #7. See Response to EPA Comment #7.

EPA Comment #19

ATI proposed existing cyclone system as the most effective control technology for Planer Mill #2 (SN-25). At least two PSD facilities installed a combination of cyclone and baghouse controlling PM_{10} emission in their planer mill operation.

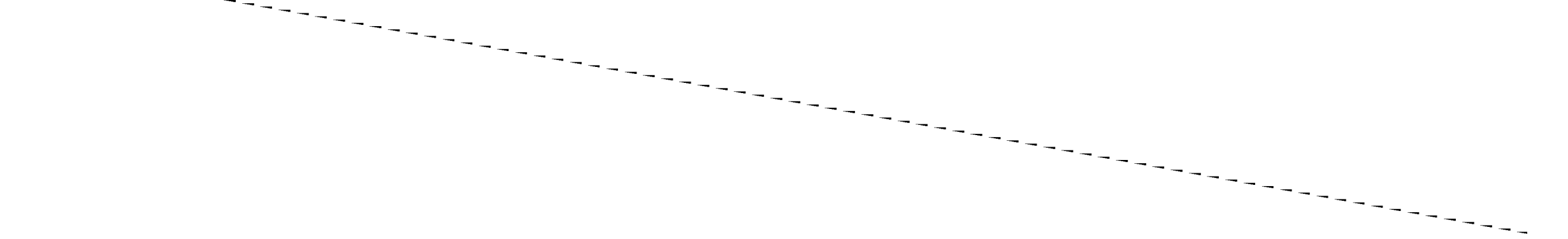
Boise Building Solutions Manufacturing, LLC, Kettle Falls Lumber and facility's permit (AOP# 07AQ-E240, issued 12/26/07) and RBLC#FL-0217 for Champion International Co. (PSD-FL-271 issued 10/17/2001) used dual control system. The visible emissions will be limited to 5% opacity at all times, and particulate emissions from the baghouse exhaust are less than 0.01 gr/dscf. ATI should justify their claim that cost is economically infeasible while their competitors installed 10 years ago.

Response to EPA Comment #19

The application included a cost effective analysis which supports ATI's claim that while there are technically feasible control devices that none of the controls are economically feasible. Below is a summary of the cost effective analysis.

Control Technology	$ / ton pollutants removed
Baghouse and Filter	$163,163

Packed-Tower Wet Scrubber	$343,870
Electrostatic Precipitator	$108,775



ADEQ
OPERATING
AIR PERMIT

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

Permit No. : 0456-AOP-R4

IS ISSUED TO:

Anthony Timberlands, Inc.
Second and Plum Streets
Bearden, AR 71720
Ouachita County
AFIN: 52-00035

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:

September 15, 2009 AND September 14, 2014

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

Signed:

Mike Bates
Chief, Air Division

September 15, 2009
Date

Table of Contents

List of Acronyms and Abbreviations

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

SECTION I: FACILITY INFORMATION

PERMITTEE:	Anthony Timberlands, Inc.
AFIN:	52-00035
PERMIT NUMBER:	0456-AOP-R4
FACILITY ADDRESS:	Second and Plum Streets Bearden, AR 71720
MAILING ADDRESS:	P.O. Box 137 Bearden, AR 71720
COUNTY:	Ouachita County
CONTACT NAME:	Steven Anthony
CONTACT POSITION:	President
TELEPHONE NUMBER:	870-687-3611
REVIEWING ENGINEER:	Charles Hurt, P.E.
UTM North South (Y):	Zone 15: 3731422.24 m
UTM East West (X):	Zone 15: 535562.15 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Anthony Timberlands, Incorporated (AFIN: 52-00035) owns and operates a pine sawmill physically located at Second and Plum Streets in downtown Bearden (Ouachita County), Arkansas. Anthony submitted a Title V renewal application which includes modifications to permitted emission limits for existing equipment. Particulate emissions from the haul roads were quantified, and two previous permit modifications were subjected to retroactive PSD review. Anthony did not request permission to install new equipment. Overall, permitted PM, PM_{10}, SO_2, VOC, CO and NO_X increased by 104.5 tpy, 70.6 tpy, 1.2 tpy, 0.6 tpy, 416.0 tpy, and 11.0 tpy respectively.

Process Description

Log Processing

Pine logs are transported by truck from the forest to the facility. Rubber-tired mobile equipment unloads the logs which are transferred to either the in-feed system for immediate processing, dry storage for near future processing, or the wet storage area for long-term future demands.

The wet storage system is self-contained consisting of a storage area, a water storage pond, and a wet circulation system. Pumps are used to spray water from the pond onto logs in the storage area. The runoff from the spraying operations is gravity fed back into the water storage pond for reuse.

In-feed systems convey the logs one at a time to the debarkers (SN-23) where bark is removed. The bark is collected in hoppers and conveyed to a green fuel storage area. From this point the collected bark and sawdust is conveyed to the four waste fuel fired boilers, one Hurst Hybrid Boiler (SN-01), two Babcock/Wilcox Boilers (SN-02 and SN-03), and Hurst Super Boiler (SN-22). All of the boilers are equipped with Zurn multicyclones to control particulate matter generated from combustion operations.

Sawmill

The debarked logs proceed to the sawmill or to the small log mill, depending on their size. They are cut by deck saws (SN-24) into different lengths (i.e., 8 to 20 feet in multiples of two) and manufactured into rough dimension lumber. The lumber is trimmed and edged to dimensions that can be dried and converted to a sellable product while minimizing the amount of waste generated. The wood waste is gathered in chutes and hoppers before being conveyed to chippers (total of three present). The chippers use screens to reduce the wood chips into 7/8 inches to 1 inch length, 2 to 1 inch in width, and 1/8 to 3/16 inches in thickness. The sized chips are pneumatically conveyed before being discharged into storage/loadout bins. Particulate matter from the small log mill chipper (SN-04), the 3 bay chip bin (SN-05), and sawdust bin (SN-06) is controlled by clones.

The sawdust generated from sawing operations is transferred to the bark and sawdust conveyors to be utilized as boiler fuel or loaded out and sold to outside markets. The sawdust is blown through SN-06 before loaded into a truck. When sawdust is burned as boiler fuel, the SN-06 can be used to control chips produced at the sawmill chipper.

Green lumber is submerged in a 7,900 gallon dip vat (SN-17) containing chemicals to prevent the decaying and staining of the lumber and to remove any insects that may still be residing on the lumber. Only certain lumber is dipped in this tank.

Drying Kilns

Five steam heated drying kilns (SN-12, SN-13, SN-14, SN-15, and SN-16) are employed to reduce the moisture content of the lumber from approximately 55 to 19 percent on a dry basis. Four kilns include two Hemco kilns (SN-12 and SN-13) and two Irving-Moore kilns (SN-14 and SN-15) are identical in size (10,500 MBF/hr) while the remaining one, Irvington-Moore kiln (SN-16) is the smallest rated kiln (3,500 MBF/hr). A total, maximum lumber throughput of 200,000,000 board feet per year may be dried in these kilns.

The dried lumber is cooled before being sent through the finishing process. In this operation the lumber is dressed to convert the texture from a rough sawn to a smooth finish. Wood shavings are generated from this finishing process. The majority of these wood shavings are sold for use in the manufacturing of particle board; however, a small portion can be pulverized, sold as wood flour, or burned for fuel.

Planner Mill #1 and #2

The wood shavings are generated a planner mill #1 (SN-07) and planner mill #2 (SN-25) with both planner mills controlled by cyclone. Trim saws, dry trim hogs, and planer machines are located at these mills. These shavings are gathered and pneumatically conveyed before being dumped by a manned system into trucks. If additional boiler fuel is needed, the shavings from the planer mills can be passed through two cyclones in series before being transferred to the green fuel storage building (SN-09).

A small amount of wood shavings can be converted to wood flour. This process involves the conveying of the shavings from storage to hammermills for size reduction. The flour is pneumatically conveyed from the hammermills through a cyclone (SN-08) before being loaded out.

Prevention of Significant Deterioration

Basis for PSD Review

Permit No. 456-AOP-R2 was issued on June 24, 2004 and required for the first time stack testing for PM_{10} and CO for SN-02 and SN-03. Anthony conducted the required stack testing on

November 11, 2005 on SN-03 for both pollutants, and the results of the tests indicated the permitted limits based on AP-42 emission factors significantly under estimated actual emissions.

Had this testing been conducted before 456-AOP-R0 was issued this facility would have been classified as a major source under 40 CFR §52.21. Anthony identified two PSD modifications which occurred after the issuance of Permit No. 456-AOP-R0, a kiln construction project (Permit No. 456-AOP-R1) and the construction of a second planer mill (SN-25) with an increase in dried lumber throughput from 135 MMBF/yr to 200 MMBF/yr (Permit No. 456-AOP-R3). The kiln production project triggered PSD review for VOC, only. For the construction of the second planer mill, PSD review was triggered for PM_{10}, VOC, CO, and NO_X.

Kiln Project: BACT

In order to identify the existing control technologies for drying kilns searches of the US EPA RACT/BACT/LAER Clearinghouse (RBLC), previously issued state permits, state and federal regulations, and other available sources were made. Anthony utilized the "top-down" approach to select BACT for the kiln project. Anthony determined there are no existing control technologies for drying kilns. Therefore, BACT for this project is "no controls" and hourly and ton per year limits are based on a production limit of 3.5 lb VOC per thousand board feet. The hourly and annual limits are 36.75 lb VOC/hr (3-hour average) and for SN-14 and SN-15, 12.25 lb VOC/hr (3-hour average) for SN-16, and 350 tpy VOC for all kilns.

Kiln Project: Air Quality Analysis

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The primary purpose of the air quality analysis is to demonstrate that new emissions emitted from a major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment.

Anthony performed modeling to demonstrate compliance with NAAQS for ozone. The predicted ambient concentration was determined to be below NAAQS. Based on information submitted by Anthony, the kiln project will not cause nor contribute to a violation of federal air quality standards. A PSD increment has not been established for VOC or Ozone. Thus, the kiln project is not subject to increment analysis.

Kiln Project: Additional Impacts – Growth

An applicant for a PSD permit must prepare additional impact analyses for each pollutant subject to the regulation under the Clean Air Act Amendments (CAAA) which will be emitted by the proposed new emission sources or modification. Anthony considered factors such as increase in workforce, housing, expansion in the surrounding community, and additional jobs created by the kiln project. Anthony indicated the construction jobs and housing associated with the kiln

project will be temporary and of minimal impact to the surround community. The operation of the kilns is not expected to create additional jobs at the facility.

Kiln Project: Additional Impacts – Soils and Vegetation

An applicant for a PSD permit must prepare additional impact analyses for each pollutant subject to the regulation under the CAAA which will be emitted by the proposed new emission sources or modification. Anthony did not identify any soils or vegetation that would be sensitive to the amount of VOC emitted from the kiln project or the possible resulting ozone concentration in the ambient air.

Kiln Project: Additional Impacts – Visibility

An applicant for a PSD permit must prepare additional impact analyses for each pollutant subject to the regulation under the CAAA which will be emitted by the proposed new emission sources or modification. VOC is the only pollutant associated with the kiln project. Particulate matter and Nitrogen Dioxide (NO_2) do not result as a part of the kiln project. Therefore, visibility screening was not necessary.

Kiln Project: 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. VOC is the only pollutant associated with the kiln project, and a Class I Increment has not been established for ozone or its surrogate. Particulate matter and nitrogen dioxide (NO_2) do not result as a part of the kiln project. Therefore, visibility screening was not necessary.

Planer Mill (SN-25): BACT

In order to identify the existing control technologies for the planer mill searches of the US EPA RACT/BACT/LAER Clearinghouse (RBLC), previously issued state permits, state and federal regulations, and other available sources were made. Anthony utilized the "top-down" approach to select BACT for the planer mill project. Anthony identified baghouse and filter, wet scrubber, electrostatic precipitators and cyclone as technically feasible control technologies. Further review indicated that that none of the identified technically feasible control technologies were economically feasible. Therefore, BACT for this project is "no controls" and hourly and ton per year limits are based on a production limit of 0.01 lb PM_{10} per ton woodwaste. The hourly and annual limits are 0.2 lb PM_{10}/hr (3-hour average) and 0.3 tpy PM_{10}.

Planer Mill (SN-25): Air Quality Analysis

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The primary purpose of the air quality analysis is to demonstrate that new emissions emitted from a major stationary source, in conjunction with other applicable emissions

from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment.

Anthony performed modeling to demonstrate compliance with NAAQS for PM_{10}, CO, and NO_X. The modeled offsite impact was determined to be below each pollutant's respective standard. Increment modeling was also performed for PM_{10} and NO_X. For each of these pollutants, the maximum increase of offsite impacts was below significant impact level (*i.e.* 1 $\mu g/m^3$). Thus, the planer mill project was not subject to a full increment analysis.

Planer Mill (SN-25): Additional Impacts – Growth

An applicant for a PSD permit must prepare additional impact analyses for each pollutant subject to the regulation under the Clean Air Act Amendments (CAAA) which will be emitted by the proposed new emission sources or modification. Anthony considered factors such as increase in workforce, housing, expansion in the surrounding community, and additional jobs created by the planer mill project. Anthony indicated the construction jobs and housing associated with the planer mill project will be temporary and of minimal impact to the surround community. The operation of the planer mill project is not expected to create additional jobs at the facility.

Planer Mill (SN-25): Additional Impacts – Soils and Vegetation

An applicant for a PSD permit must prepare additional impact analyses for each pollutant subject to the regulation under the CAAA which will be emitted by the proposed new emission sources or modification. Anthony did not identify any soils or vegetation that would be sensitive to the amount of PM_{10}, VOC, CO, or NO_X emitted from the planer mill project or the possible resulting ozone concentration in the ambient air.

Planer Mill (SN-25): Additional Impacts – Visibility

An applicant for a PSD permit must prepare additional impact analyses for each pollutant subject to the regulation under the CAAA which will be emitted by the proposed new emission sources or modification. Screening of emission sources is conducted to assess the possibility of visibility impairment in the area impacted by the planer mill. Results of the first level of screening indicated that no adverse impact from the planer mill project is expected. Therefore, additional visibility screening was not necessary.

Planer Mill (SN-25): Class I Area Impact Analysis

The facility is approximately 145 km from Caney Creek which is the nearest Class I Area. The impact on visibility and increment consumption for NO_X and PM_{10} were evaluated. The facility was modeled out to 10km from the facility using AERMOD, and neither modeled pollutants exceed the Class I Area Significant Impact Level. Therefore, it is presumed that this project will have no adverse effect on increment consumption in Class I Areas. The results of the modeling are listed below:

Pollutant	Class I Area Significant Impact Level* ($\mu g/m^3$)	Averaging Period	Offsite Impact ($\mu g/m^3$)
PM_{10}	0.3	24-hour	0.15
PM_{10}	0.2	Annual	0.013
NO_X	0.1	Annual	0.08

* See Page 38292 Federal Register / Vol. 61, No. 142 / Tuesday, July 23, 1996.

The permittee utilized VISCREEN to assess the impact visibility on Caney Creek. . The results predicted that light extinction and change in contrast were below the first level of screening (*i.e.* $\Delta E \leq 2.0$ and $C_p \leq 0.05$). Based on the worst cast emission of pollutants which affect visibility and the distance of the source from the nearest Class I area and FLAG guidance, the (Q/D) is less than 3.6 for all Class I areas that can be potentially affected by activities at the facility. Therefore, it is presumed this project will have no adverse effect on any Class I area visibility.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective January 25, 2009
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective January 25, 2009
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective January 25, 2009
40 CFR Part §52.21 *Prevention of Significant Deterioration of Air Quality*
40 CFR Part 60, Subpart Dc – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

* SN-01 and SN-22 are subject to the NSPS. SN-02 and SN-03 were constructed before June 9, 1989 and have not been modified or reconstructed since.

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	Emissions	
			lb/hr	tpy
Total Allowable Emissions		PM	98.8	283.2
		PM_{10}	77.1	231.8
		SO_2	4.4	12.5
		VOC	167.9	363.9
		CO	225.8	753.7
		NO_X	37.4	110.0
HAPs (included in VOC or PM/PM_{10} totals unless noted otherwise)		Acenaphtylene	8.60E-04	2.50E-03
		Acetaldehyde	1.78	3.90
		Acrolein	0.60	2.60
		Benzene	0.31	2.10
		Benzo(a)pyrene	1.80E-03	1.30E-03
		Cadmium	7.00E-04	2.10E-03
		Chlorine [D]	0.05	0.40
		Fluorene	5.76E-04	1.70E-03
		Formaldehyde	1.63	4.10
		HCl [D]	3.30	9.50
		Lead	8.20E-03	2.40E-02
		Manganese	0.27	0.80
		Mercury	6.00E-04	5.40E-03
		Methanol	12.05	26.50
		Phenol	8.80E-03	2.60E-02
		Styrene	0.33	0.95

Emission Summary				
Source Number	Description	Pollutant	Emissions	
			lb/hr	tpy
01	Hurst Hybrid Boiler (Boiler #2) 28.7 MMBtu/hr	PM	10.1	240.7 [A]
		PM_{10}	9.2	218.8 [A]
		SO_2	0.8	12.5 [A]
		VOC	0.5	8.5 [A]
		CO	21.6	753.7 [A]
		NO_X	6.4	110.0 [A]
		Acenaphtylene	0.00015	2.50E-03 [A]
		Acrolein	0.12	2.00 [A]
		Benzene	0.13	2.10 [A]
		Benzo(a)pyrene	0.00075	1.30E-03 [A]
		Cadmium	0.00012	2.10E-03 [A]
		Chlorine	0.023	0.40 [A]
		Fluorene	0.000098	1.70E-03 [A]
		Formaldehyde	0.13	2.20 [A]
		HCl	0.55	9.50 [A]
		Lead	0.0014	0.024 [A]
		Manganese	0.046	0.80 [A]
		Mercury	0.0001	1.80E-03 [A]
		Phenol	0.0015	0.026 [A]
		Styrene	0.055	0.95 [A]
02	Babcock/Wilcox Boiler (Boiler #3) 55.5 MMBtu/hr	PM	28.2	240.7 [A]
		PM_{10}	25.7	218.8 [A]
		SO_2	1.4	12.5 [A]
		VOC	1.0	8.5 [A]
		CO	91.3	753.7 [A]
		NO_X	12.3	110.0 [A]
		Acenaphtylene	0.00028	2.50E-03 [A]
		Acrolein	0.23	2.00 [A]
		Benzene	0.24	2.10 [A]
		Benzo(a)pyrene	0.00015	1.30E-03 [A]
		Cadmium	0.00023	2.10E-03 [A]
		Chlorine	0.044	0.40 [A]
		Fluorene	0.00019	1.70E-03 [A]
		Formaldehyde	0.25	2.20 [A]
		HCl	1.10	9.50 [A]
		Lead	0.0027	0.024 [A]
		Manganese	0.089	0.80 [A]
		Mercury	0.0002	1.80E-03 [A]
		Phenol	0.0029	0.026 [A]
		Styrene	0.11	0.95 [A]

Emission Summary				
Source Number	Description	Pollutant	Emissions	
			lb/hr	tpy
03	Babcock/Wilcox Boiler (Boiler #4) 55.5 MMBtu/hr	PM	28.2	240.7 [A]
		PM_{10}	25.7	218.8 [A]
		SO_2	1.4	12.5 [A]
		VOC	1.0	8.5 [A]
		CO	91.3	753.7 [A]
		NO_X	12.3	110.0 [A]
		Acenaphtylene	0.00028	2.50E-03 [A]
		Acrolein	0.23	2.00 [A]
		Benzene	0.24	2.10 [A]
		Benzo(a)pyrene	0.00015	1.30E-03 [A]
		Cadmium	0.00023	2.10E-03 [A]
		Chlorine	0.044	0.40 [A]
		Fluorene	0.00019	1.70E-03 [A]
		Formaldehyde	0.25	2.20 [A]
		HCl	1.1	9.50 [A]
		Lead	0.0027	0.024 [A]
		Manganese	0.089	0.80 [A]
		Mercury	0.0002	1.80E-03 [A]
		Phenol	0.0029	0.026 [A]
		Styrene	0.11	0.95 [A]
22	Hurst Hybrid Boiler (Boiler #5) 28.7 MMBtu/hr	PM	10.1	240.7 [A]
		PM_{10}	9.2	218.8 [A]
		SO_2	0.8	12.5 [A]
		VOC	0.5	8.5 [A]
		CO	21.6	753.7 [A]
		NO_X	6.4	110.0 [A]
		Acenaphtylene	0.00015	2.50E-03 [A]
		Acrolein	0.12	2.00 [A]
		Benzene	0.13	2.10 [A]
		Benzo(a)pyrene	0.00075	1.30E-03 [A]
		Cadmium	0.00012	2.10E-03 [A]
		Chlorine [D]	0.023	0.40 [A]
		Fluorene	0.000098	1.70E-03 [A]
		Formaldehyde	0.13	2.20 [A]
		HCl [D]	0.55	9.50 [A]
		Lead	0.0014	0.024 [A]
		Manganese	0.046	0.80 [A]
		Mercury	0.0001	1.80E-03 [A]
		Phenol	0.0015	0.026 [A]
		Styrene	0.055	0.95 [A]
4	Small Log Mill Chipper	PM	0.9	3.0
		PM_{10}	0.5	1.7
5	Chip Bin	PM	0.1	0.4
		PM_{10}	0.1	0.1
6	Sawdust Bin	PM	0.6	1.9
		PM_{10}	0.1	0.1

Emission Summary				
Source Number	Description	Pollutant	Emissions	
			lb/hr	tpy
7	Planer Shaving Cyclone	PM	0.3	0.5 [B]
		PM_{10}	0.2	0.3 [B]
9	Planer Shaving Cyclone	PM	0.3	0.5 [B]
		PM_{10}	0.2	0.3 [B]
11	Planer Shaving Cyclone	PM	0.3	0.5 [B]
		PM_{10}	0.2	0.3 [B]
12	Drying Kiln #1 Hemco	VOC	36.8	350.0 [C]
		Acetaldehyde	0.41	3.90 [C]
		Acrolein	0.07	0.60 [C]
		Formaldehyde	0.2	1.90 [C]
		Methanol	2.78	26.50 [C]
13	Drying Kiln #2 Hemco	VOC	36.8	350.0 [C]
		Acetaldehyde	0.41	3.90 [C]
		Acrolein	0.07	0.60 [C]
		Formaldehyde	0.2	1.90 [C]
		Methanol	2.78	26.50 [C]
14	Drying Kiln #3 Irving-Moore	VOC	36.8	350.0 [C]
		Acetaldehyde	0.41	3.90 [C]
		Acrolein	0.07	0.60 [C]
		Formaldehyde	0.2	1.90 [C]
		Methanol	2.78	26.50 [C]
15	Drying Kiln #4 Irving-Moore	VOC	36.8	350.0 [C]
		Acetaldehyde	0.41	3.90 [C]
		Acrolein	0.07	0.60 [C]
		Formaldehyde	0.2	1.90 [C]
		Methanol	2.78	26.50 [C]
16	Drying Kiln #5 Irvington-Moore	VOC	12.3	350.0 [C]
		Acetaldehyde	0.14	3.90 [C]
		Acrolein	0.03	0.60 [C]
		Formaldehyde	0.07	1.90 [C]
		Methanol	0.93	26.50 [C]
17	Chemical Dip Tank	VOC	5.4	5.4
23	Log Debarking	PM	0.6	1.0
		PM_{10}	0.3	0.6
24	Log Sawing	PM	4.7	8.5
		PM_{10}	2.7	4.9
25	Planer Mill #2 Cyclone	PM	0.3	0.5 [B]
		PM_{10}	0.2	0.3 [B]
26	Paved Roads	PM	14.1	27.2
		PM_{10}	2.8	5.3

[A] Total Annual Emissions for SN-01, SN-02, SN-03, and SN-22
[B] Total Annual Emissions for SN-07, SN-09, SN-11, and SN-25
[C] Total Annual Emissions for SN-12, SN-13, SN-14, SN-15, and SN-16
[D] Not Included in VOC or PM/PM_{10} totals.

SECTION III: PERMIT HISTORY

Air permit 456-A was the initial State Implementation Plan (SIP) permit for Bearden Lumber Company. The permit was issued on March 24, 1978 for the permitting of two wood waste fired boilers to be used in the sawmill operations. These new boilers were replacing an existing wood waste fired boiler which would only be used for standby. The only permitted emission rate was particulate at 40 pounds per hour per boiler.

Air permit 456-AR-1 was issued to Bearden Lumber Company on 1993. This permit was issued to allow the operation of all three boilers, to quantify emissions using more up to date information, and to address emission sources and pollutants not previously addressed. Emissions were estimated using USEPA AP-42 emission factors. Other emissions of particulate matter from existing sources were quantified using process knowledge and manufacturer's quoted efficiencies for the respective control equipment.

An administrative amendment to air permit 456-AR-1 was issued on September 1, 1995. This permit was issued to address two changes: the elimination of SN-10, the Rip Saw Rework Station Cyclone and the installation of a new, more efficient cyclone at SN-07, the Planer Shavings Cyclone (although permitted emissions did not change).

Arkansas operating permit #456-AOP-R0 was issued June 8, 1999. It was the first operating permit issued to Bearden Lumber Company under Regulation 26. The facility modified the previous air permit by increasing the total lumber production for the facility, removing the wood flour operation, permitting five steam heated lumber drying kilns, permitting of a lumber dip tank, permitting of three underground fuel tanks, and permitting of one above ground kerosene tank. The facility also removed one old 20,000 lb/hr of steam Struthers Wells boiler and replaced it with two 20,700 lb/hr of steam Hurst boilers. These boilers were more efficient than the old boilers, and therefore, there was a decrease in total permitted emissions.

During the Department's initial review of the Title V permit application, it was determined that Drying Kiln #4 (SN-15) which had been installed in 1989 had emissions greater than 40 tpy of VOCs, and therefore, should have previously been subject to PSD review. A retroactive PSD analysis was performed for this permit.

Permit 456-AOP-R1 was issued on January 23, 2001. This permit authorized the installation of three new lumber drying kilns (SN-14, SN-15, and SN-16) to replace the three old lumber drying kilns that burned down in April 2000. The increase from the installation of the kilns was 236.3 tpy VOC.

Permit 456-AOP-R2 was issued on June 24, 2004. This Title V air permit quantified emissions from two existing emission sources, log debarking (SN-23) and log sawing (SN-24), and also allowed an annual emissions bubble for the four boilers (SN-01, SN-02, SN-03, and SN-22). Compliance Assurance Monitoring (CAM) Rule requirements were specified for the four boilers, as well as stack testing provisions for SN-02 and SN-03. Finally, this permit incorporated the most up-to-date emission factors in the emission rate calculations.

Permit 456-AOP-R3 was issued on September 23, 2005. Bearden Lumber Company installed a planer mill (SN-25) and associated control equipment. This modification loosened the facility's production bottleneck, and it allowed the facility to increase production from 135 to 200 million board feet per year. The VOC emissions increased from 232.2 tpy (actual) to 361.3 tpy (permitted), an increase of 129.1 tpy. The expansion also increased CO emissions from 170.0 tpy (actual) to 337.5 tpy (permitted), an increase of 167.5 tpy.

SECTION IV: SPECIFIC CONDITIONS

SN-01, SN-02, SN-03, and SN-22
Hurst Hybrid Boilers (Boiler #2 and #5) and Babcock/Wilcox Boilers (Boiler #2 and #3)

Source Description

Sources SN-01 and SN-22 are Hurst Hybrid boilers each with a maximum steam rating of 20,700 lb/hr of steam (28.7 MMBtu/hr). The boilers were installed in 1997. Due to their heat input capacity and date of installation, these boilers are subject to 40 CFR Part 60, Subpart Dc – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. They are equipped with a Zurn Multi-cyclone to control particulate matter emissions.

Sources SN-02 and SN-03 are Babcock/Wilcox boilers each with a maximum steam rating of 40,000 lb/hr of steam (55.5 MM Btu/hr). The boilers were installed in 1978. These boilers are not subject to Subpart Dc because they were installed before the effective date of the subpart. They are equipped with a Zurn Multi-cyclone to control particulate matter emissions.

The boilers are only used to supply steam to the five steam heated lumber drying kilns. The boilers use woodwaste as fuel to generate heat energy and to alleviate potential solid waste disposal problems. The woodwaste is generated on-site and includes all green material (i.e., bark and sawdust). If the need presents itself, especially during the winter months, planer shavings may be utilized as dry fuel, or fuel can be imported from outside sources. Fuel may also be exported during the warm weather months when the facility steam demand is lower than normal.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The hourly pollutant emission rates are based on the heat input capacity and AP-42 emission factors except where required to test. Compliance with the annual limits shall be demonstrated through compliance with Specific Condition #6. For CO compliance with the annual limit shall be demonstrated through compliance with Specific Conditions #6 and #8. [Regulation 19, §19.501 *et seq.*, and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01	Hurst Hybrid Boiler (Boiler #2) 28.7 MMBtu/hr	PM_{10}	9.2	218.8*
		SO_2	0.8	12.5*
		VOC	0.5	8.5*
		CO	21.6	753.7*
		NO_X	6.4	110.0*
02	Babcock/Wilcox Boiler (Boiler #3) 55.5 MMBtu/hr	PM_{10}	25.7	218.8*
		SO_2	1.4	12.5*
		VOC	1.0	8.5*
		CO	91.3	753.7*
		NO_X	12.3	110.0*

SN	Description	Pollutant	lb/hr	tpy
03	Babcock/Wilcox Boiler (Boiler #4) 55.5 MMBtu/hr	PM_{10}	25.7	218.8*
		SO_2	1.4	12.5*
		VOC	1.0	8.5*
		CO	91.3	753.7*
		NO_X	12.3	110.0*
22	Hurst Hybrid Boiler (Boiler #5) 28.7 MMBtu/hr	PM_{10}	9.2	218.8*
		SO_2	0.8	12.5*
		VOC	0.5	8.5*
		CO	21.6	753.7*
		NO_X	6.4	110.0*

* Total emission limit for the boilers at the facility (SN-01, SN-02, SN-03 and SN-22)

2. The permittee shall not exceed the emission rates set forth in the following table. The hourly pollutant emission rates are based on the heat input capacity and AP-42 emission factors except where required to test. Compliance with the annual limits shall be demonstrated through compliance with Specific Condition #6. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01	Hurst Hybrid Boiler (Boiler #2) 28.7 MMBtu/hr	PM	10.1	240.7*
		Acenaphtylene	0.00015	2.5E-03*
		Acrolein	0.12	2.00*
		Benzene	0.13	2.10*
		Benzo(a)pyrene	0.00075	1.3E-03*
		Chlorine	0.023	0.40*
		Fluorene	0.000098	1.7E-03*
		Formaldehyde	0.13	2.20*
		HCl	0.55	9.50*
		Phenol	0.0015	0.026*
		Styrene	0.055	0.95*
		Cadmium	0.00012	2.1E-03*
		Lead	0.0014	0.024*
		Manganese	0.046	0.80*
		Mercury	0.0001	1.8E-03*
02	Babcock/Wilcox Boiler (Boiler #3) 55.5 MMBtu/hr	PM	28.2	240.7*
		Acenaphtylene	0.00028	2.5E-03*
		Acrolein	0.23	2.00*
		Benzene	0.24	2.10*
		Benzo(a)pyrene	0.00015	1.3E-03*
		Chlorine	0.044	0.40*
		Fluorene	0.00019	1.7E-03*
		Formaldehyde	0.25	2.20*
		HCl	1.1	9.50*
		Phenol	0.0029	0.026*
		Styrene	0.11	0.95*
		Cadmium	0.00023	2.1E-03*
		Lead	0.0027	0.024*
		Manganese	0.089	0.80*
		Mercury	0.0002	1.8E-03*

SN	Description	Pollutant	lb/hr	tpy
03	Babcock/Wilcox Boiler (Boiler #4) 55.5 MMBtu/hr	PM	28.2	240.7*
		Acenaphtylene	0.00028	2.5E-03*
		Acrolein	0.23	2.00*
		Benzene	0.24	2.10*
		Benzo(a)pyrene	0.00015	1.3E-03*
		Chlorine	0.044	0.40*
		Fluorene	0.00019	1.7E-03*
		Formaldehyde	0.25	2.20*
		HCl	1.1	9.50*
		Phenol	0.0029	0.026*
		Styrene	0.11	0.95*
		Cadmium	0.00023	2.1E-03*
		Lead	0.0027	0.024*
		Manganese	0.089	0.80*
		Mercury	0.0002	1.8E-03
22	Hurst Hybrid Boiler (Boiler #5) 28.7 MMBtu/hr	PM	10.1	240.7*
		Acenaphtylene	0.00015	2.5E-03*
		Acrolein	0.12	2.00*
		Benzene	0.13	2.10*
		Benzo(a)pyrene	0.00075	1.3E-03*
		Chlorine	0.023	0.40*
		Fluorene	0.000098	1.7E-03*
		Formaldehyde	0.13	2.20*
		HCl	0.55	9.50*
		Phenol	0.0015	0.026*
		Styrene	0.055	0.95*
		Cadmium	0.00012	2.1E-03*
		Lead	0.0014	0.024*
		Manganese	0.046	0.80*
		Mercury	0.0001	1.8E-03

* Total emission limit for the boilers at the facility (SN-01, SN-02, SN-03 and SN-22)

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
01	20%	§19.503
02	20%	§19.503
03	20%	§19.503
22	20%	§19.503

4. SN-01, SN-02, SN-03 and SN-22 are subject to the Compliance Assurance Monitoring (CAM) Rule and shall comply with all applicable provisions, including but not limited to: [Regulation 19, §19.304 and 40 CFR Part 64]

Daily observations of the opacity from each source shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such

observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations

5. Wood residue shall be the only fuel combusted at SN-01, SN-02, SN-03, and SN-22 Wood residue is hogged wood, bark, sawdust, shavings, chips, mill rejects, sanderdust, or wood trim. [Regulation No. 19, §19.705, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

6. The permittee shall comply with the following steam production limits. Compliance with this condition shall be demonstrated through compliance with Specific Condition #7. [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]

Source	Daily Steam Production limit (lb/day)	Annual Steam Production Limit (lb/year)
SN-01	496,800	1.813×10^8
SN-02	960,000	3.504×10^8
SN-03	960,000	3.504×10^8
SN-22	496,800	1.813×10^8

7. The facility shall maintain monthly records that demonstrate compliance with the limits set in Specific Condition #6 which may be used by the Department for enforcement purposes. These 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. An annual total and each individual month's steam production data shall be submitted to the Department in accordance with General Provision #7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

8. The permittee shall not operate SN-02 or SN-03 for more than 7,884 hours per consecutive 12-month period per source. [Regulation No. 19, §19.705, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

9. The permittee shall maintain a 12-month rolling total the number of hours SN-02 and SN-03 operate. These records shall be updated by the 15th day of the month following the month to which the records pertain, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7. [Regulation No. 19, §19.705 and 40 CFR Part 52, Subpart E]

10. SN-01 and SN-22 are subject to all applicable requirements of the New Source Performance Standards (NSPS) Subpart Dc provisions as identified in the Code of Federal Regulations (CFR) Title 40, Part 60.40c. The applicable requirements include, but are not limited to Specific Conditions #11 and #12: [40 CFR Part 60 Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*]

11. The permittee shall record and maintain records of the amount of fuel combusted during each day. [Regulation No. 19, §19.304 and 40 CFR §60.48c (g)]

12. The permittee shall maintain all records required by Specific Condition #11 for a period of two years following the date of such record. [Regulation No. 19, §19.304 and 40 CFR §60.48c (i)]

13. The permittee shall test SN-01, SN-02, SN-03, and SN-22 as specified below. The initial tests shall be conducted in accordance with Plantwide Condition #3. All subsequent tests shall be conducted no more than three months prior to the submittal of each Title V renewal application, and the title page and summary of results of the test report shall be included in the renewal application. Failure to demonstrate compliance with the hourly emission limits in Specific Condition #1 will require annual testing until two consecutive tests demonstrate the failed source complies with Specific Condition #1. [Regulation No. 19, §19.702 and 40 CFR Part 52, Subpart E]

Source	Pollutant	Test Method	Notes
SN-01, SN-02, SN-03, SN-22	PM_{10}	201 A	Test one boiler of each size once every five years. SN-01 and SN-22 are 28.7 MMBTU/hr, and SN-02 and SN-03 are 55.5 MMBTU/hr.
SN-01, SN-02, SN-03, SN-22	CO	10	Test one boiler of each size once every five years. SN-01 and SN-22 are 28.7 MMBTU/hr, and SN-02 and SN-03 are 55.5 MMBTU/hr.

Source	Pollutant	Test Method	Notes
SN-01, SN-02, SN-03, SN-22	NO_X	7E	Test one boiler of each size once every five years. SN-01 and SN-22 are 28.7 MMBTU/hr, and SN-02 and SN-03 are 55.5 MMBTU/hr.

SN-04
Small Log Mill Chipper

Source Description

Debarked logs are conveyed to the sawmill or small log mill where deck saws cut the logs into different lengths in multiples of two feet. The logs are then converted to lumber which is trimmed and edged to dimensions that can be dried to a final product. Chutes and hoppers collect the woodwaste before it is conveyed to the chippers. The chippers employ screens to reduce the wood chips into pieces of specified length, width, and thickness. The small log mill chipper employs a cyclone to control particulate matter emissions. The cyclone is assumed to have a control efficiency of 95%

Specific Conditions

14. The permittee shall not exceed the emission rates set forth in the following table for source SN-04. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
04	Small Log Mill Chipper	PM_{10}	0.5	1.7

15. The permittee shall not exceed the emission rates set forth in the following table for source SN-04. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
04	Small Log Mill Chipper	PM	0.9	3.0

16. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
04	20%	§19.503

17. Daily observations of the opacity from SN-04 shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the

permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations

SN-05
Chip Bin

Source Description

Source SN-05 is the sawmill's chip bin. The sized chips produced by the small log mill chipper (SN-04) are conveyed through a cyclone before being loaded out onto trucks. The chip bin employs a cyclone to control particulate matter emissions. The cyclone is assumed to have a control efficiency of 95%

Specific Conditions

18. The permittee shall not exceed the emission rates set forth in the following table for source SN-05. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05	Chip Bin	PM_{10}	0.1	0.1

19. The permittee shall not exceed the emission rates set forth in the following table for source SN-04. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
05	Chip Bin	PM	0.1	0.4

20. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
05	20%	§19.503

21. Daily observations of the opacity from SN-05 shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall

maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations

SN-06
Sawdust Bin

Source Description

Source SN-06 is the sawmill's sawdust bin. Green sawdust generated from sawing operations is transferred to the bark and sawdust conveyors to be utilized as a boiler fuel or loaded out to be sold. The sawdust is blown through a two bay bin cyclone before being loaded onto a truck. The cyclone is assumed to have a control efficiency of 95%.

Specific Conditions

22. The permittee shall not exceed the emission rates set forth in the following table for source SN-06. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
06	Sawdust Bin	PM_{10}	0.1	0.1

23. The permittee shall not exceed the emission rates set forth in the following table for source SN-06. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
06	Sawdust Bin	PM	0.6	1.9

24. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
06	20%	§19.503

25. Daily observations of the opacity from SN-06 shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall

implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations

SN-09
Planer Shavings Cyclone
(Green Fuel Storage)

Source Description

Source SN-09 is the sawmill's green fuel storage building planer shavings cyclone. At times, wood shavings produced from finishing operations pass through the Planer Shavings Cyclone (SN-11) and this cyclone before being transferred to the Green Fuel Storage Building and eventually the boilers for steam generation. These cyclones are only operated during high fuel demand periods for the boilers. The cyclone is assumed to have a control efficiency of 95%.

Specific Conditions

30. The permittee shall not exceed the emission rates set forth in the following table for source SN-09. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
09	Planer Shaving Cyclone	PM_{10}	0.2	0.3*

* Planer emissions bubble of SN-07, SN-09, SN-11, and SN-25

31. The permittee shall not exceed the emission rates set forth in the following table for source SN-09. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
09	Planer Shaving Cyclone	PM	0.3	0.5*

* Planer emissions bubble of SN-07, SN-09, SN-11, and SN-25

32. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
09	20%	§19.503

33. Daily observations of the opacity from SN-09 shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the

permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observationsThe permittee shall not exceed the emission rates set forth in the following table.

SN-11
Planer Shavings Cyclone

Source Description

Source SN-11 is one of the sawmill's planer shavings cyclone. At times, wood shavings generated from finishing operations pass through this cyclone and the Planer Shavings Cyclone (SN-09) before being transferred to the Green Fuel Storage Building and eventually the boilers for steam generation. These cyclones are only operated when additional fuel is required for the boilers. The cyclone is assumed to have a control efficiency of 95%.

Specific Conditions

34. The permittee shall not exceed the emission rates set forth in the following table for source SN-11. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
11	Planer Shaving Cyclone	PM_{10}	0.2	0.3*

* Planer emissions bubble of SN-07, SN-09, SN-11, and SN-25

35. The permittee shall not exceed the emission rates set forth in the following table for source SN-11. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
11	Planer Shaving Cyclone	PM	0.3	0.5*

* Planer emissions bubble of SN-07, SN-09, SN-11, and SN-25

36. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
11	20%	§19.503

37. Daily observations of the opacity from SN-11 shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the permittee shall immediately take action to identify the cause of the visible emissions,

implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations.

SN-12, SN-13, SN-14, SN-15, and SN-16
Drying Kilns #1, #2, #3, #4, and #5

Source Description

SN-12 and SN-13 are Hemco drying kilns that were installed in 1990. SN-14 and SN-15 are Irving Moore drying kilns that were installed in 1991. SN-16 is an Irvington-Moore Drying kiln that was installed in 1991. The lumber kilns at the facility are used to reduce the moisture content in the green lumber produced in the sawmill from 55% to 19%. Each kiln contains vents that allow the water vapor driven off from the wood to escape. Naturally occurring VOCs in the wood are also driven off and escape out the kiln vents with the water vapor.

Specific Conditions

38. The permittee shall not exceed the emission rates set forth in the following. The lb/hr pollutant emission rates are based on the maximum capacity of the equipment and a BACT limit 3.5 lb VOC/MBF. Compliance with the tpy limit shall be demonstrated by the throughput limit in Specific Condition #40 and a BACT limit of 3.5 lb VOC/MBF. Compliance with the BACT limit shall be demonstrated by proper kiln design and maintenance. [Regulation 19, §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
12	Drying Kiln #1 Hemco	VOC	36.8	350.0*
13	Drying Kiln #2 Hemco	VOC	36.8	350.0*
14	Drying Kiln #3 Irving-Moore	VOC	36.8	350.0*
15	Drying Kiln #4 Irving-Moore	VOC	36.8	350.0*
16	Drying Kiln #5 Irvington-Moore	VOC	12.3	350.0*

* Drying Kiln Emission Bubble

39. The permittee shall not exceed the emission rates set forth in the following table. The lb/hr pollutant emission rates are based on the maximum capacity of the equipment. Compliance with the tpy limit shall be demonstrated by the throughput limit in Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
12	Drying Kiln #1 Hemco	Acetaldehyde Acrolein Formaldehyde Methanol	0.41 0.07 0.20 2.78	3.90* 0.60* 1.90* 26.50*

SN	Description	Pollutant	lb/hr	tpy
13	Drying Kiln #2 Hemco	Acetaldehyde	0.41	3.90*
		Acrolein	0.07	0.60*
		Formaldehyde	0.20	1.90*
		Methanol	2.78	26.50*
14	Drying Kiln #3 Irving-Moore	Acetaldehyde	0.41	3.90*
		Acrolein	0.07	0.60*
		Formaldehyde	0.20	1.90*
		Methanol	2.78	26.50*
15	Drying Kiln #4 Irving-Moore	Acetaldehyde	0.41	3.90*
		Acrolein	0.07	0.60*
		Formaldehyde	0.20	1.90*
		Methanol	2.78	26.50*
16	Drying Kiln #5 Irvington-Moore	Acetaldehyde	0.14	3.90*
		Acrolein	0.03	0.60*
		Formaldehyde	0.07	1.90*
		Methanol	0.93	26.50*

* Drying Kiln Emission Bubble

40. The permittee shall not dry more than 200 million board feet of lumber at the facility during any consecutive twelve month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

41. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #40 and may be used by the Department for enforcement purposes. Compliance shall be determined on a monthly basis by totaling the amount of board feet of lumber dried for the previous 12 months. Each 12 month total shall be available for inspection by the last day of the month after the reported 12 months. These records shall be maintained on site, made available to Department personnel upon request, submitted every six months in accordance with the requirement of General Provision #7. [Regulation 19, '19.705 and 40 CFR Part 52, Subpart E]

SN-17
Chemical Dip Tank

Source Description

Source SN-17 is the sawmill's chemical dip tank. Green lumber is submerged in chemicals to prevent the decaying and staining of the lumber and to remove any insects that may still be present on the lumber. The dipping chemicals are stored in a 7,900 gallon open top vat. Not all of the green lumber is dipped in this tank.

Specific Conditions

42. The permittee shall not exceed the emission rates set forth in the following table for source SN-11. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #43. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
17	Chemical Dip Tank	VOC	5.4	5.4

43. The permittee shall not exceed the usage rate of 7,500 gallons of dipping chemicals during any consecutive twelve month period and a maximum VOC weight content of 1.44 pounds per gallon. [Regulation 19 §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

44. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #43 and may be used by the Department for enforcement purposes. Compliance shall be determined on a monthly basis by totaling the amount of dipping chemicals used during the previous twelve months. Each twelve-month total shall be available for inspection by the last day of the month after the reported twelve months. These records shall be maintained on site, made available to Department personnel upon request, and submitted every six month in accordance with the requirement of General Provision #7. [Regulation 19, §19.705, and 40 CFR Part 52, Subpart E]

SN-23 and SN-24
Log Debarking and Sawing

Source Description

Infeed systems convey the log at a time to the one of the three (3) debarkers where bark is removed. The Bandmill Debarker is for large logs and the two (2) Sharp Chain Debarkers are for smaller logs. The debarked logs are then delivered to the sawmill where the logs are ripped into green dimensional lumber. The bark is collected in hoppers, mixed with sawdust, and conveyed by a chain conveyor to the boilers to be used as fuel.

Specific Conditions

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

SN	Description	Pollutant	lb/hr	tpy
23	Log Debarking	PM_{10}	0.3	0.6
24	Log Sawing	PM_{10}	2.7	4.9

46. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
23	Log Debarking	PM	0.6	1.0
24	Log Sawing	PM	4.7	8.5

SN-25
Planer Mill #2 Cyclone

Source Description

This planer mill consists of a trim saw, a dry trim hog, and a planer machine. The shavings generated are collected by vacuum hoods and pans on branch lines, conveyed to a common system, routed to a blower, and conveyed by air to a centrifugal cyclone collector.

Specific Conditions

47. The permittee shall not exceed the emission rates set forth in the following table for source SN-25. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by a production limit of 0.01 lb PM_{10} per ton woodwaste throughput and proper maintenance of the planer mill and cyclone. [Regulation 19, §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
25	Planer Mill #2 Cyclone	PM_{10}	0.2	0.3*

* Planer emissions bubble of SN-07, SN-09, SN-11, and SN-25

48. The permittee shall not exceed the emission rates set forth in the following table for source SN-25. The pound per hour and the ton per year pollutant emission rates are based on the maximum capacity of the equipment and are effectively limited by Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
25	Planer Mill #2 Cyclone	PM	0.3	0.5*

* Planer emissions bubble of SN-07, SN-09, SN-11, and SN-25

49. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Regulation No. §19, 19.503 and 40 CFR Part 52, Subpart E]

SN	Limit	Regulatory Citation
25	20%	§19.503

50. Daily observations of the opacity from SN-25 shall be conducted by personnel trained and certified in EPA Reference Method 9. The permittee shall accept such observations for demonstration of compliance. Such observations shall be conducted at particular times when violations are likely to occur (*i.e.* during startup and shutdown). If visible emissions which appear to be in excess of the permitted opacity are detected, the permittee shall immediately take action to identify the cause of the visible emissions,

implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated daily, kept on site, made available to Department personnel upon request, and submitted every six months in accordance with the requirements of General Provision #7.

a. The date and time of the observation
b. If visible emissions which appeared to be above the permitted limit were detected
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations

SN-26
Paved Roads

Source Description

Particulate emissions result from commercial traffic on facility controlled paved roads.

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 through compliance with Specific Condition #40. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
26	Paved Roads	PM_{10}	2.8	5.3

52. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #40. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
26	Paved Roads	PM	14.1	27.2

53. The permittee shall not operate in a manner such that emissions from the paved roads would cause a nuisance off-site or allow visible emissions from extending beyond the property boundary. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance provided that there are no complaints received by the Department regarding dust from the facility. [§18.501 and A.C.A. §8 4-203 as referenced by §8-4-304 and §8-4-311]

54. The permittee shall sweep the paved roads as necessary to control emissions from extending beyond the property boundary. The permittee shall mechanically sweep the paved roads once per month or more frequently as determined by weekly observations. The permittee shall maintain records of such weekly observations and shall update these records following each observation or sweeping. These records shall be kept onsite and be made available to Department personnel upon request. [§18.1004 and A.C.A. §8 4-203 as referenced by §8-4-304 and §8-4-311]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Anthony Timberlands, Inc. 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]

Title VI Provisions

7. 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 placem ent 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 ma y modify, remove, or interfere with the required warning statement except as described in §82.112.

8. 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 t he 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 sma ll 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.

9. 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.

10. 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.

11. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated (*insert application date*).

Description	Category
Underground Gasoline Storage Tank (10,000 gallons)	A-13
Underground Diesel Fuel Storage Tank (14,000 gallons)	A-3
Underground Diesel Fuel Storage Tank (10,000 gallons)	A-3
Kerosene Aboveground Storage Tank (250 gallons)	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)]

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 Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

        i. The facility name and location;
        ii. The process unit or emission source deviating from the permit limit;
        iii. The permit limit, including the identification of pollutants, from which deviation occurs;
        iv. The date and time the deviation started;
        v. The duration of the deviation;
        vi. The average emissions during the deviation;
        vii. The probable cause of such deviations;
        viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
        ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by 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)]

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.

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 SO_2control 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 SO_2control 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 SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

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 SO_2control 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 SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

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

§ 60.42c Standard for sulfur dioxide (SO_2).

(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 SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in 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 SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in 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 SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of SO_2in 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 SO_2emissions limit or the 90 percent SO_2reduction 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 SO_2emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 50 percent (0.50) of the potential SO_2emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in

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 SO_2reduction 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 SO_2in 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 SO_2in 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 SO_2in excess of the following:

(1) The percent of potential SO_2emission rate or numerical SO_2emission 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= SO_2emission 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_2emission 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_2emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2control) 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_2emission 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 SO_2emissions 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 SO_2emission 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 affect 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 SO_2emission limits under §60.42c is based on the average percent reduction and the average SO_2emission 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 SO_2emission 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 SO_2emission rate (E_{ho}) and the 30-day average SO_2emission 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:

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

Where:

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

E_{ho}= Hourly SO_2emission rate, ng/J (lb/MMBtu);

E_w= SO_2concentration 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 SO_2emission 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 SO_2emission rate is computed using the following formula:

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

Where:

$\%P_s$= Potential SO_2emission rate, in percent;

$\%R_g$= SO_2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2removal 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}o from paragraph (e)(1) of this section and an adjusted average SO_2inlet rate (E_{ai}o) using the following formula:

$$\%R_{go} = 100\left(1 - \frac{E^{\circ}_{ao}}{E^{\circ}_{ai}}\right)$$

Where:

$\%R_g$o = Adjusted $\%R_g$, in percent;

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

$E_{ai}o$ = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai}o$, an adjusted hourly SO_2 inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

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

Where:

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

E_{hi}= Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by 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 (O_2) or carbon dioxide (CO_2) 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 O_2or CO_2measurements 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 O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) 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 theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O2 (or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours 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 SO_2emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations at the outlet of the SO_2control device (or the outlet of the steam generating unit if no SO_2control 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 SO_2concentrations and either O_2or CO_2concentrations at both the inlet and outlet of the SO_2control device.

(b) The 1-hour average SO_2emission 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 SO_2emission 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 SO_2emission 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 SO_2CEMS at the inlet to the SO_2control device shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted, and the span value of the SO_2CEMS at the outlet from the SO_2control device shall be 50 percent of the maximum estimated hourly potential SO_2emission 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 SO_2CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission 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 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 SO_2input 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 SO_2at the inlet or outlet of the SO_2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and CO_2measurement 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 SO_2standards 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, SO_2, 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; 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 SO_2 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 SO_2 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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CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to Anthony Timberlands, Inc., P.O. Box 137, Bearden, AR, 71720, on this 15th day of September, 2009.

Cynthia Hook, AAII, Air Division