

RESPONSE TO COMMENTS

Anthony Forest Products Company
Permit No.: 1681-AOP-R8
AFIN: 70-00473

On September 5, 2008 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 September 26, 2008:

Comment #1

Cover page and Page 4: The facility address should indicate the proper location of Urbana, AR rather than EI Dorado, AR.

Response to Comment #1

The facility address has been updated.

Comment #2

Page 6, Process Description: In the first paragraph, second sentence, the word "planes" should be replaced by "planers".

Response to Comment #2

The typographical error has been corrected.

Comment #3

Page 6, Process Description: The last sentence of the first paragraph should be revised to read as follows: Fugitive emissions associated with the planer mill woodwaste storage bins (SN-07) have been designated as an insignificant activity.

Response to Comment #3

The last sentence of the process description has been revised.

Comment #4

Page 8, Emission Summary Table: The manganese lb/hr limit for SN-13 should be corrected to 6.77E-02 lb/hr. This is consistent with the emission calculations and emission rate table which were submitted with the renewal application.

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Response to Comment #4

The typographical error has been corrected.

Comment #5

Page 14, Specific Condition #8: This condition should be revised to require that the records be updated weekly, rather than daily. This will make the record keeping requirement consistent with the requirement that opacity readings be conducted on a weekly basis.

Response to Comment #5

Agree. The draft document has been revised to require records of VE to be updated weekly.

Comment #6

Page 17, Specific Condition #12: The manganese lb/hr limit for SN-13 should be corrected to 6.77E-02 lb/hr. This is consistent with the emission calculations and emission rate table which were submitted with the renewal application.

Response to Comment #6

The typographical error has been corrected.

Comment #7

Page 18, Specific Condition #17: It is requested that this condition be revised in order to require the testing within 120 days of permit issuance rather than 60 days. It appears likely that this permit will be issued final around the first of November, which would likely result in the testing being conducted around the holiday season. Revising this condition to allow for 120 days would alleviate this concern.

Response to Comment #7

Agree. Specific Condition #17 has been revised to allow 120 days after permit issuance for the required testing.

Comment #8

Page 20, Specific Condition #20: It is requested that this condition be revised to require that the chemical dust suppressant be applied at least once every six months rather than once per month. According to manufacturer's data, the chemical suppressant proposed for use by Anthony Forest

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Products is able to effectively reduce particulate emissions from roads for a period of 6-12 months after a single application. Manufacturer's information on this product is enclosed with this letter.

Response to Comment #8

Agree. Specific Condition #20 has been revised to read as follows:

The permittee shall apply a chemical dust suppressant at a rate no less frequent than an application is effective as specified by the manufacturer or no less frequent than once a month (if a frequency is not specified by the manufacturer) to all unpaved roads under the control of the permittee. The permittee shall once a month observe the roads for visible emissions generated by traffic and maintain a record of such observations. If visible emission can be observed, then the permittee shall either use wet suppression or re-apply a chemical dust suppressant as needed. [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]

Comment #9

Page 25, Insignificant Activities: The insignificant activities list in the permit lists two 500 gallon diesel fuel tanks. One of these should be removed from the permit. ADEQ incorrectly listed two 500 gallon diesel tanks rather than one 500 gallon and one 600 gallon tank. The 600 gallon Planer Diesel Tank has been removed from the facility.

Response to Comment #9

Agree. The Insignificant Activities Table has been revised as follows:

Description	Category
1000 gallon AST (gasoline)	A-13
500 gallon AST (diesel fuel)	A-3
1000 gallon AST (diesel fuel)	A-3
1000 gallon AST (diesel fuel)	A-3
Bark Storage Piles	A-13
Sawdust Piles	A-13
Boiler Ash Piles	A-13
Planer Mill Woodwaste Storage Bins	A-13

ADEQ

ARKANSAS
Department of Environmental Quality

November 3, 2008

Kelly Olivier
EHS Coordinator
Anthony Forest Products Company
PO Box 724
Strong, AR 71765

Dear Mr. Olivier:

The enclosed Permit No. 1681-AOP-R8 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. 1681-AOP-R8 for the construction, operation and maintenance of an air pollution control system for Anthony Forest Products Company to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under §2.1.14 of Regulation No. 8, Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, 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 §2.1.14 of Regulation No. 8.

Sincerely,



Mike Bates
Chief, Air Division

ADEQ OPERATING AIR PERMIT

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

Permit No. : 1681-AOP-R8

IS ISSUED TO:


Anthony Forest Products Company
1236 Urbana Road
Urbana, AR 71768
Union County
AFIN: 70-00473

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

November 3, 2008 AND November 2, 2013

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

Signed:



Mike Bates
Chief, Air Division

November 3, 2008
Date

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Appendix A

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

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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

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SECTION I: FACILITY INFORMATION

PERMITTEE: Anthony Forest Products Company
AFIN: 70-00473
PERMIT NUMBER: 1681-AOP-R8
FACILITY ADDRESS: 1236 Urbana Road
Urbana, AR 71768
MAILING ADDRESS: PO Box 724
Strong, AR 71765
COUNTY: Union County
CONTACT NAME: Kelly Olivier
CONTACT POSITION: EHS Coordinator
TELEPHONE NUMBER: 870-962-3206
REVIEWING ENGINEER: Charles Hurt, P.E., P.E.
UTM North South (Y): Zone 15: 3669126.84 m
UTM East West (X): Zone 15: 551893.98 m

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SECTION II: INTRODUCTION

Summary of Permit Activity

Anthony Forest Products Company (AFIN: 70-00473) operates a sawmill and ancillary operations in Urbana, Arkansas. Anthony submitted a Title V renewal application. Emission calculations for PM₁₀ for several sources were revised based on updated emission factors and estimate methodology. As a result of these changes the permitted PM₁₀ emission from planer cyclones (SN-03 and SN-04) and the sawmill (SN-06) were reduced, and the permitted emissions from the bark (SN-18A), sawdust (SN-18B), and ash (SN-19) storage pile and the planer mill woodwaste bin (SN-07) were reclassified as insignificant activities (A-13). Emissions from the log yard road (SN-20) were identified and quantified for the first time. Anthony also requested to modify the PM and PM₁₀ emission limits by increasing the limits for all three boilers because Boiler #3 (SN-16) failed the required stack test. Overall, permitted PM and PM₁₀ emission limits decreased by 0.9 tpy and 58.9 tpy, respectively.

In addition to the changes listed above, the requirements of 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* were removed because the subpart has been vacated.

Process Description

Logs are taken by truck to the Sawmill (SN-06) where they are debarked and sawed into cants or rough lumber. The lumber is then edged and trimmed. Trimmings and edgings are routed to a chipper. Chips are pneumatically conveyed to shake screens where blocks and fines are removed. The chips are then belt conveyed to a chip bin and eventually loaded into tractor trailers. Bark and sawdust are conveyed to the boiler fuel storage. Excess material is routed to loading stations loaded into tractor trailers, and transported off site for use as fuel.

Blocks are routed back to the chipper. Chipper fines are routed to boiler fuel storage or to a trailer loader for shipment off-site. The blower, which conveys the materials to the shaker screen, has an associated cyclone, which vents inside the sawmill building.

From the Sawmill, the lumber is stored and stacked. The lumber is then dried in kilns (Dry Kilns #2 and #3). The dry kilns are heated by steam generated in wood burning boilers.

Water vapor, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) are evaporated from the wood in the lumber drying process. Dry Kiln #2 is designated as SN-02; and Dry Kiln #3 is designated as SN-14. These kilns are steam heated, exhausting only water vapor, VOC, and HAPs evaporated from the wood.

The wood-fuel boilers burn southern pine sawdust, bark, and other wood residue, including shavings. The boiler stacks (designated as SN-12, SN-13, and SN-16) exhaust products of combustion.

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Dried lumber is stored in protected areas before planing. The dried lumber is planed in the planer mill prior to shipping. Two planers, a hammer hog, a trimmer, a rip saw, and a re-saw are located in the Planer Mill. This equipment has two associated cyclones with vent designations SN-03 and SN-04. The SN-03 cyclone (Planer Cyclone #1) collects material (primarily shavings and sawdust) from the large planer (Planer #1), from the hammer hog, and the rip saw located in the planer building. The SN-04 cyclone (Planer Cyclone #2) collects material from the smaller planer. Fugitive emissions associated with the planer mill wood waste storage bins (SN-07) have been designated as an insignificant activity.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
<i>Arkansas Air Pollution Control Code, Regulation 18, effective February 15, 1999</i>
<i>Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective October 15, 2007</i>
<i>Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective September 26, 2002</i>
<i>40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial – Commercial – Institutional Steam Generating Units</i>
<i>40 CFR Part 63, Subpart DDDD – National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products*</i>

* The facility is subject to the subpart. Other than initial notification, there are no applicable requirements of the subpart.

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	43.3	188.7
		PM ₁₀	18.6	80.2
		SO ₂	1.5	6.6
		VOC	70.6	244.4
		CO	45.0	197.1
		NO _x	25.6	112.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	Total Allowable Non-Criteria Pollutant Emissions (included in VOC totals unless noted otherwise)	Acetaldehyde	0.77	2.64
		Acrolein	0.73	2.21
		Benzene	0.60	1.80
		Cadmium	2.02E-03	8.84E-03
		Chromium	1.86E-03	8.15E-03
		Formaldehyde	1.00	2.90
		HCl ^C	1.26	5.46
		Lead	2.29E-03	0.01
		Manganese	0.20	0.86
		Mercury	1.28E-04	5.62E-04
		Methanol	4.10	13.90
		Nickel	4.45E-03	1.95E-02
		Styrene	0.30	0.90
02	Dry Kiln #2	VOC	31.3 ^B	236.3 ^A
		Acetaldehyde	0.35 ^B	2.64 ^A
		Acrolein	0.06 ^B	0.41 ^A
		Methanol	1.90 ^B	13.90 ^A
		Formaldehyde	0.20 ^B	1.10 ^A
03	Planer Cyclone #1	PM	7.1	31.1
		PM ₁₀	2.9	12.5
04	Planer Cyclone #2	PM	3.4	14.9
		PM ₁₀	1.4	6.0
06	Sawmill	PM	13.9	60.8
		PM ₁₀	0.4	1.3
12	Wood-Fired Boiler #1 (29.56 MMBTU/hr)	PM	5.2	22.4
		PM ₁₀	4.3	18.7
		SO ₂	0.5	2.2
		VOC	0.6	2.7
		CO	15.0	65.7
		NO _x	8.5	37.3
		Acrolein	0.2	0.6
		Benzene	0.2	0.6
		Cadmium	6.71E-04	2.94E-03
		Chromium	6.19E-04	2.71E-03
		Formaldehyde	0.2	0.6
		HCl	0.42	1.82
		Lead	7.61E-04	3.33E-03
		Manganese	7.32E-02	0.32
		Mercury	4.25E-05	1.87E-04
		Nickel	1.48E-03	6.47E-03
	Styrene	0.1	0.3	

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
13	Wood-Fired Boiler #2 (29.56 MMBTU/hr)	PM	5.2	22.4
		PM ₁₀	4.3	18.7
		SO ₂	0.5	2.2
		VOC	0.6	2.7
		CO	15.0	65.7
		NO _x	8.5	37.3
		Acrolein	0.2	0.6
		Benzene	0.2	0.6
		Cadmium	6.71E-04	2.94E-03
		Chromium	6.19E-04	2.71E-03
		Formaldehyde	0.2	0.6
		HCl	0.42	1.82
		Lead	7.61E-04	3.33E-03
		Manganese	6.77E-02	0.30
		Mercury	4.25E-05	1.87E-04
		Nickel	1.48E-03	6.47E-03
Styrene	0.1	0.3		
14	Dry Kiln #3	VOC	37.5 ^B	236.3 ^A
		Acetaldehyde	0.42 ^B	2.64 ^A
		Acrolein	0.07 ^B	0.41 ^A
		Methanol	2.20 ^B	13.90 ^A
		Formaldehyde	0.20 ^B	1.10 ^A
16	Wood-Fired Boiler #3 (29.75 MMBTU/hr)	PM	5.2	22.6
		PM ₁₀	4.3	18.8
		SO ₂	0.5	2.2
		VOC	0.6	2.7
		CO	15.0	65.7
		NO _x	8.6	37.7
		Acrolein	0.2	0.6
		Benzene	0.2	0.6
		Cadmium	6.75E-04	2.96E-03
		Chromium	6.23E-04	2.73E-03
		Formaldehyde	0.2	0.6
		HCl	0.42	1.82
		Lead	7.66E-04	3.35E-03
		Manganese	5.38E-02	0.24
		Mercury	4.28E-05	1.88E-04
		Nickel	1.49E-03	6.51E-03
Styrene	0.1	0.3		
20	Log Yard Road	PM	3.3	14.5
		PM ₁₀	1.0	4.2

^A Total emissions for Dry Kilns #2 and #3.

^B Maximum average hourly emission rate based on maximum kiln cycle capacity.

^C Not included in VOC total.

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SECTION III: PERMIT HISTORY

The initial permit #1681-A was issued on March 3, 1996. A Title V permit application was submitted for the Urbana sawmill on July 15, 1996, which included the following proposed changes to the existing SIP permit:

1. An increase in annual production at the facility;
2. Installation of two wood-fired boilers.
3. Installation of a third dry kiln, a cyclone, and other equipment.

The original Title V permit, #1681-AOP-R0, was issued on September 12, 1997. It included some provisions in the specific conditions dealing with visible emissions from the boilers that reflected new EPA enforcement guidelines. These conditions were not included in the original Draft permit that had been submitted to Anthony Forest Products, and the company challenged these changes because they had been denied an opportunity to respond.

A revised version was prepared after discussion with the applicant, and issued as 1681-AOP-R1 on January 13, 1998.

Permit #1681-AOP-R2 was issued on August 6, 1999. This permit changed the required hourly steam readings in the wood-fired boilers from hourly readings to a maximum 24 hour rate of 489,600 pounds per day.

Permit #1681-AOP-R3 was issued on September 18, 2001. The Lumber Dry Kiln #1 (SN-01) has been removed from service as a result of a fire that destroyed the kiln and combustion equipment in April 2000. The permit minor modification also allowed increased production capacity for the Planer Mill (SN-03, 04, 07, and 15) and the two remaining Dry Kilns (SN-02 and 14). VOC annual emissions from Dry Kilns #2 and #3 have increased by 19.25 tpy, with decreases in other criteria pollutants based on revised estimates. There were no new emission sources.

Permit #1681-AOP-R4 was issued on June 14, 2002. Anthony requested to add a 29.8 MMBtu/hr wood-fired boiler (SN-16), a lumber drying kiln (SN-17), and to increase the permitted production capacity to 650,000 tons per year for the planer mill and the lumber kilns to 135,000,000 board feet per year to account for the increased production from the installation of a new kiln. Anthony also requested Planer Cyclone #3 (SN-15) to be removed because the cyclone was never installed. The source descriptions for the Planer Cyclone #1 and the Planer Mill emissions were revised. The emissions from the sawmill were declared as an insignificant activity in the previous permits; however, these emissions from the sawmill do not classify as an insignificant activity and will be included in this revision as a permitted emission source. Emissions generated from the bark and saw dust storage piles (SN-18) will also be included in the permit as a permitted emission source.

Permit #1681-AOP-R5 was issued on December 16, 2003. This was the first Title 5 Renewal for the facility. The facility also requested to install a completely enclosed air lock system to route shavings and sawdust from the Planer Mill (SN-07) to an existing fuel storage bin on an as

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needed basis. PM emissions did not change due to the installation of the air lock system, and the total waste from the Planer Mill did not increase. PM and VOC emissions increased by 48.2 tpy and 39.7 tpy, respectively. PM₁₀ and Heavy Metals emissions decreased by 23.5 tpy and 1.5 tpy, respectively. Changes in emissions are due to revised methods of calculation and updated emission factors.

Permit #1681-AOP-R6 was issued on March 23, 2007 to incorporate the applicable requirements of 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters and to revise the particulate matter emission limits in order to account for emission control provided by the building enclosure. The VOC and HAP emission limits were also revised in order to correct a rounding error in the previous estimates. Dry Kiln #4 (SN-17) was removed. The two remaining dry kilns consumed the production capacity of Dry Kiln #4. Permitted PM and HAPs decreased by 25.1 tpy and 5.91 tpy, respectively. Permitted PM₁₀ and VOC increased by 2.4 tpy and 2.7 tpy, respectively.

Permit #1681-AOP-R7 was issued on July 31, 2007 which incorporated the applicable requirements of 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*. No physical changes or changes to method of operation were requested.

SECTION IV: SPECIFIC CONDITIONS

SN-02 and SN-14

Dry Kiln #2 and Dry Kiln #3

Source Description

Dry kilns #2 and #3 dehydrate lumber continuously, 8,760 hours per year. The kilns are permitted to produce 135 MMBF/yr of dried lumber. They operate exclusively on the steam from the three wood-fired boilers.

Specific Conditions

- The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 19 §19.501 *et seq.* effective October 15, 2007, and 40 CFR Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
02	VOC	31.3 ^B	
14	VOC	37.5 ^B	
Total	VOC	-	236.3 ^A

A Total VOC emissions for Dry Kilns #2 and #3.

B Maximum average hourly emission rate based on maximum kiln cycle capacity.

- The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Pollutant	lb/hr	tpy
02	Acetaldehyde	0.35 ^B	-
	Acrolein	0.06 ^B	
	Methanol	1.90 ^B	
	Formaldehyde	0.20 ^B	
14	Acetaldehyde	0.42 ^B	-
	Acrolein	0.07 ^B	
	Methanol	2.20 ^B	
	Formaldehyde	0.20 ^B	
Total	Acetaldehyde	-	2.64 ^A
	Acrolein		0.41 ^A
	Methanol		13.90 ^A
	Formaldehyde		1.10 ^A

A Total VOC emissions for Dry Kilns #2 and #3.

B Maximum average hourly emission rate based on maximum kiln cycle capacity.

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3. The facility shall not exceed more than a total of 135 MMBF of kiln dried lumber produced in any consecutive 12 month period. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

4. The facility shall maintain records which demonstrate compliance with the limit set in Specific Condition #3 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 kiln 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]

SN-03 and SN-04

Planer Cyclone #1 and Planer Cyclone #2

Source Description

Dried lumber is stored in protected areas before planing. The dried lumber is planed in the planer mill prior to shipping. Two planers, a hammer hog, a trimmer, a rip saw, and a resaw are located in the Planer Mill. This equipment has two associated cyclones, with vent designations SN-03 and SN-04. The SN-03 cyclone (#1) collects material (primarily shavings and sawdust) from the large planer (Planer #1), from the hammer hog, from the re-cut saw, and from the rip saw located in the planer building. The SN-04 cyclone (#2) collects material from the smaller planer.

Specific Conditions

- The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 19 §19.501 *et seq.* effective October 15, 2007, and 40 CFR Part 52, Subpart E]

Source Number	Pollutant	lb/hr	tpy
03	PM ₁₀	2.9	12.5
04	PM ₁₀	1.4	6.0

- The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source Number	Pollutant	lb/hr	tpy
03	PM	7.1	31.1
04	PM	3.4	14.9

- The permittee shall not cause to be discharged to the atmosphere sources SN-03 and SN-04 visible emissions which exhibit an opacity greater than 20%. The opacity shall be measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60 Appendix A. [Regulation No. 19 §19.501 and 40 CFR Part 52, Subpart E]
- Weekly observations of the opacity from SN-03 and SN-04 shall be conducted by personnel familiar with the visual emissions at the facility. The permittee shall accept such observation for demonstration of compliance. The permittee shall maintain personnel trained, but not necessarily certified, in EPA Reference 9. If visible emissions in excess of the permitted opacity are detected the permittee shall immediately take

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corrective action to identify the cause of the visible emissions, implement corrective actions, and document that visible emissions comply with the permitted opacity following the corrective action. The permittee shall maintain records which demonstrate compliance with Specific Condition #7. The records of each observation shall be updated weekly, kept on site, and made available to Department personnel upon request. The permittee shall maintain the following records: [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

- a. The date and time of the observation;
- b. Detection of visible emissions over the permitted limits;
- c. The cause of the exceedance of the opacity limit;
- d. The corrective action taken;
- e. The opacity after corrective action was taken; and
- f. The name of the person conducting the opacity observations.

SN-06

Sawmill

Source Description

Logs are taken by truck to the sawmill where they are debarked and sawed into cants or rough lumber. The lumber is then edged and trimmed. Trimmings and edgings are routed to a chipper. Chips are pneumatically conveyed to shaker screens where blocks and fines are removed. The chips are then belt conveyed to a chip bin and eventually loaded into tractor trailers. Bark and sawdust are conveyed to boiler fuel storage. Excess material is routed to the loading stations, loaded into tractor trailers, and transported off-site for the use fuel.

Blocks are routed back to the chipper. Chipper fines are routed to the boiler fuel storage, or to a tractor trailer loader for shipment off-site. The blower which conveys the materials to the shaker screens has an associated cyclone which vents inside the sawmill building.

Specific Conditions

9. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 19 §19.501 *et seq.* effective October 15, 2007, and 40 CFR Part 52, Subpart E]

Source Number	Pollutant	lb/hr	tpy
06	PM ₁₀	0.4	1.3

10. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source Number	Pollutant	lb/hr	tpy
06	PM	13.9	60.8

SN-12, SN-13, and SN-16

Wood Fired Boilers #1, #2, and #3

Source Description

The wood-fired boilers supply steam to the kilns, and burn southern pine sawdust, bark, and other wood residue, including shavings. The products of combustion are exhausted through three boiler stacks (SN-12, SN-13, and SN-16). Each boiler is equipped with a cyclone to control particulate emissions.

The three boilers, supplied by Wellons, Inc., are affected facilities as defined in Paragraph 60.40c of NSPS Subpart Dc- (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units). The two older boilers have a maximum design input capacity of 29.56 MMBtu/hr each, and the newest boiler has a design input capacity of 29.75 MMBtu/hr. The boilers are below the 30 MMBtu/hr threshold limit for the particulate standard contained in Paragraph 60.7 of the NSPS regulations. Based on the maximum throughput rate of 20,400 lb/hr of 422 °F steam at 300 psig, and feed water at 220 °F for Boiler #1 and Boiler #2 actual heat output has been calculated at 20.8 MMBtu/hr. Based on the maximum throughput rate of 20,700 lb/hr of 366 °F steam at 150 psig, and feed water at 220 °F for Boiler #3, actual heat output has been calculated at 20.9 MMBtu/hr.

Specific Conditions

11. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #16. [Regulation No. 19 §19.501 *et seq.* effective October 15, 2007, and 40 CFR Part 52, Subpart E]

Source Number	Pollutant	lb/hr	tpy
12	PM ₁₀	4.3	18.7
	SO ₂	0.5	2.2
	VOC	0.6	2.7
	CO	15.0	65.7
	NO _x	8.5	37.3
13	PM ₁₀	4.3	18.7
	SO ₂	0.5	2.2
	VOC	0.6	2.7
	CO	15.0	65.7
	NO _x	8.5	37.3
16	PM ₁₀	4.3	18.8
	SO ₂	0.5	2.2
	VOC	0.6	2.7
	CO	15.0	65.7
	NO _x	8.6	37.7

12. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #16. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source Number	Pollutant	lb/hr	tpy
12	PM	5.2	22.4
	Acrolein	0.2	0.6
	Benzene	0.2	0.6
	Cadmium	6.71E-04	2.94E-03
	Chromium	6.19E-04	2.71E-03
	Formaldehyde	0.2	0.6
	HCl	0.42	1.82
	Lead	7.61E-04	3.33E-03
	Manganese	7.32E-02	0.32
	Mercury	4.25E-05	1.87E-04
	Nickel	1.48E-03	6.47E-03
	Styrene	0.1	0.3
13	PM	5.2	22.4
	Acrolein	0.2	0.6
	Benzene	0.2	0.6
	Cadmium	6.71E-04	2.94E-03
	Chromium	6.19E-04	2.71E-03
	Formaldehyde	0.2	0.6
	HCl	0.42	1.82
	Lead	7.61E-04	3.33E-03
	Manganese	6.77E-02	0.32
	Mercury	4.25E-05	1.87E-04
	Nickel	1.48E-03	6.47E-03
	Styrene	0.1	0.3
16	PM	5.2	22.6
	Acrolein	0.2	0.6
	Benzene	0.2	0.6
	Cadmium	6.75E-04	2.96E-03
	Chromium	6.23E-04	2.73E-03
	Formaldehyde	0.2	0.6
	HCl	0.42	1.82
	Lead	7.66E-04	3.35E-03
	Manganese	5.38E-02	0.24
	Mercury	4.28E-05	1.88E-04
	Nickel	1.49E-03	6.51E-03
	Styrene	0.1	0.3

13. The amount of steam produced in each wood-fired boiler shall be limited according to the following table. Compliance with this condition shall be demonstrated through compliance with Specific Condition #14. [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 Number	Description	Daily Limit (lb Steam/day)	Annual Limit (MM lb/12 month)
12	Boiler #1	489,600	178.7
13	Boiler #2	489,600	178.7
16	Boiler #3	489,600	178.7

14. The facility shall maintain records which demonstrate compliance with the limits set in Specific Condition #13 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]

15. The permittee shall not cause to be discharged to the atmosphere from sources SN-12, SN-13 and SN-16 visible emissions which exhibit an opacity greater than 20%. The opacity shall be measured in accordance with EPA Reference Method 9 as found in 40 CFR Part 60 Appendix A. [Regulation No. 19 §19.501 and 40 CFR Part 52, Subpart E]

16. Weekly observations of the opacity from SN-12, SN-13, and SN-16 shall be conducted by personnel familiar with the visual emissions at the facility. The permittee shall accept such observation for demonstration of compliance. The permittee shall maintain personnel trained, but not necessarily certified, in EPA Reference 9. If visible emissions in excess of the permitted opacity are detected the permittee shall immediately take corrective action to identify the cause of the visible emissions, implement corrective actions, and document that visible emissions comply with the permitted opacity following the corrective action. The permittee shall maintain records which demonstrate compliance with Specific Condition #17. The records shall be updated daily, kept on site, and made available to Department personnel upon request. The permittee shall maintain the following records: [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]
 - a. The date and time of the observation;
 - b. Detection of visible emissions over the permitted limits;
 - c. The cause of the exceedance of the opacity limit;
 - d. The corrective action taken;
 - e. The opacity after corrective action was taken; and
 - f. The name of the person conducting the opacity observations.

17. The permittee shall test source SN-16 for PM₁₀ while the source is operating at or above 90% of rated capacity using EPA Reference Methods 201A with 202. These tests shall be conducted within one hundred twenty (120) days of issuance of this permit (1681-

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AOP-R8). If the facility passes the PM₁₀ tests, the tests shall then be repeated once every five years. Failure of any test will require the permittee to repeat the testing every other year. Test results shall be maintained on-site, made available to Department personnel upon request, and shall be submitted to the Department in accordance with General Provision #7. [Regulation No. 19 §19.702 and 40 CFR Part 52, Subpart E]

SN-20

Log Yard Road

Source Description

Logs are delivered to the mill at the log yard located north of the main mill site. An unpaved road circles the log yard and is approximately 0.6 mi long. Emissions of particulate matter result from log truck traffic on this road.

Specific Conditions

18. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 19 §19.501 *et seq.* effective October 15, 2007, and 40 CFR Part 52, Subpart E]

Source Number	Pollutant	lb/hr	tpy
20	PM ₁₀	1.0	4.2

19. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by compliance with Specific Condition #3. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source Number	Pollutant	lb/hr	tpy
20	PM	3.3	14.5

20. The permittee shall apply a chemical dust suppressant at a rate no less frequent than an application is effective as specified by the manufacturer or no less frequent than once a month (if a frequency is not specified by the manufacturer) to all unpaved roads under the control of the permittee. The permittee shall once a month observe the roads for visible emissions generated by traffic and maintain a record of such observations. If visible emission can be observed, then the permittee shall either use wet suppression or re-apply a chemical dust suppressant as needed. [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]
21. The permittee shall record date of each application of chemical dust suppressant application and maintain a log the records. These records shall be kept onsite and made available to Department personnel upon request. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

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SECTION V: COMPLIANCE PLAN AND SCHEDULE

Anthony Forest Products Company will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by 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 placement of the required warning statement must comply with the requirements pursuant to §82.108.
 - c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
 - d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

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 the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
 - c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
 - d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. (“MVAC like appliance” as defined at §82.152)
 - e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
 - f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

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

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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.

Permit Shield

12. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in the following table of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated May 12, 2008.

Applicable Regulations

Source No.	Regulation	Description
12, 13, 16	40 CFR 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial – Institutional Steam Generating Units
Facility	40 CFR Part 63, Subpart DDDD	National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products

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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 May 12, 2008.

Description	Category
1000 gallon AST (gasoline)	A-13
500 gallon AST (diesel fuel)	A-3
1000 gallon AST (diesel fuel)	A-3
1000 gallon AST (diesel fuel)	A-3
Bark Storage Piles	A-13
Sawdust Piles	A-13
Boiler Ash Piles	A-13
Planer Mill Woodwaste Storage Bins	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]
2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §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 Regulation 19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:
 - i. The facility name and location;
 - ii. The process unit or emission source deviating from the permit limit;
 - iii. The permit limit, including the identification of pollutants, from which deviation occurs;
 - iv. The date and time the deviation started;
 - v. The duration of the deviation;
 - vi. The average emissions during the deviation;
 - vii. The probable cause of such deviations;

- viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
- ix. The name of the person submitting the report.

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

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

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

- 9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
- 10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]
- 11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]
- 12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]
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.

[Regulation 18, §18.102(C-D), Regulation 19, §19.103(D), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:
 - a. Such a request does not violate a federal requirement;
 - b. Such a request is temporary in nature;
 - c. Such a request will not result in a condition of air pollution;
 - d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
 - e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
 - f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18, §18.102(C-D), Regulation 19, §19.103(D), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:
 - a. The request does not violate a federal requirement;
 - b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
 - c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18, §18.102(C-D), Regulation 19, §19.103(D), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and CFR Part 52, Subpart E]

Appendix A

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

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Electronic Code of Federal Regulations

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Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

§ 60.40c Applicability and delegation of authority.

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

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

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

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

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

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

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

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, 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).

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

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

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced

upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

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

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

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

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

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

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

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

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

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO₂.

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

§ 60.42c Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

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

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

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

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

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

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

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

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

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

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

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

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

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

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

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

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

Where:

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

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

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

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

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

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

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

(f) Reduction in the potential SO₂ emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO₂ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

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

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

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

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

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

(i) The SO₂ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) 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.

§ 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 combusts 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.

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

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO₂ emissions is not subject to the PM limit in this section.

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

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under §60.42c shall be determined using a 30-day average. The first operating day

included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

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

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

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

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

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

Where:

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

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

E_w = SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

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

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

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO₂ emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

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

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

Where:

$\%P_s$ = Potential SO₂ emission rate, in percent;

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

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

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

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

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

Where:

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

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

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

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

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

Where:

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

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

E_w = SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$; and

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

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

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO₂ 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 SO₂ emissions data in calculating % P_s and E_{h_o} 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_{h_o} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

§ 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 3 of appendix A of this part shall be used for gas analysis when applying Method 5, 5B, or 17 of appendix A of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

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

- (4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.
- (5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ± 14 °C (320 ± 25 °F).
- (6) For determination of PM emissions, an oxygen (O₂) or carbon dioxide (CO₂) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.
- (7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:
- (i) The O₂ or CO₂ measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and
 - (iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.
- (8) Method 9 of appendix A of this part (6-minute average of 24 observations) 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 EPA Reference Method 5, 5B, or 17 of appendix A 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 EPA Method 5, 5B, or 17 of appendix A of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(13) 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 (d)(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 (d)(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 (d)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂(or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O₂(or CO₂), EPA reference Method 3, 3A, or 3B of appendix A 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 Audits 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.

(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).

§ 60.46c Emission monitoring for sulfur dioxide.

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

(b) The 1-hour average SO₂ emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation, and shall be

calculated using the data points required under §60.13(h)(2). Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

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

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

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

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

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

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according to the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate.

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

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO₂ at the inlet or outlet of the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and CO₂ measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part,

Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

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

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) 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 COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

(b) All COMS for measuring opacity 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) 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 (0.06 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO₂ or PM emissions are not required to operate a CEMS for measuring opacity if they follow the applicable procedures under §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.45c(d). The CEMS specified in paragraph §60.45c(d) 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) An affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO 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 for measuring opacity. 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.

(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. At least two data points per hour must be used to calculate each 1-hour average.

(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) An affected facility 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 appropriate delegated permitting authority is not required to operate a COMS for measuring opacity. 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.

§ 60.48c Reporting and recordkeeping requirements.

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

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

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

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) The owner or operator of each coal-fired, oil-fired, or wood-fired affected facility subject to the opacity limits under §60.43c(c) shall submit excess emission reports for any excess emissions from the affected

facility that occur during the reporting period.

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

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

(1) Calendar dates covered in the reporting period.

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

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

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

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

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

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

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

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

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

(1) For distillate oil:

(i) The name of the oil supplier;

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

(iii) The sulfur content 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 of the fuel in ng/J heat input; and

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

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

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

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

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the

annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

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

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

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CERTIFICATE OF SERVICE

I, Pam Owen, hereby certify that a copy of this permit has been mailed by first class mail to Anthony Forest Products Company, PO Box 724, Strong, AR, 71765, on this 3rd day of November, 2008.

Pam Owen
Pam Owen, AAI, Air Division

