Prevention of Significant Air Quality Deterioration Review
Of Archer Daniels Midland – Valdosta
Located in Lowndes County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 16260
May 2006

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program (SSPP)	Planning & Support Program
Prepared by	
Tyneshia Tate – NOx Unit	Peter Courtney – Data & Modeling Unit
Reviewed and Approved by:	
Michelle Keith – NOx Unit Coordinator James A. Capp – SSPP Manager	James Boylan – Unit Coordinator, Data & Modeling Unit
Heather Abrams – Chief, Air Protection Branch	

SUMMARY **1**

1.0 INTRODUCTION **3**

1.1 PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS 3
1.2 PROPOSAL 3
1.3 APPLICABILITY 4
1.4 PRELIMINARY DETERMINATION 5

2.0 REVIEW OF APPLICABLE RULES AND REGULATIONS **5**

2.1 STATE RULES 5
2.2 FEDERAL RULE – PSD 6
Definition of BACT *7*
2.3 FEDERAL RULE – NSPS SUBPART DC 8
2.4 FEDERAL RULE – NESHAP SUBPART DDDDD 9
2.4 FEDERAL RULE – COMPLIANCE ASSURANCE MONITORING (CAM) 17
2.5 STATE AND FEDERAL – STARTUP AND SHUTDOWN AND EXCESS EMISSIONS 18

3.0 CONTROL TECHNOLOGY REVIEW **18**

3.1 NITROGEN OXIDES 18
Combustion Controls for Thermal NOx – Base Option *19*
Selective Catalytic Reduction *20*
SCONOx® *22*
Xonon® *23*
Selective Non-Catalytic Reduction *23*
Summary of Control Technology *25*
Conclusions for NO_x *25*
3.2 CARBON MONOXIDE 26
Good Combustion Practice (GCP) - Base Option *26*
Catalytic Oxidation *27*
Conclusions for Carbon Monoxide *28*

4.0 TESTING AND MONITORING REQUIREMENTS **28**

5.0 AMBIENT AIR QUALITY REVIEW **30**

5.1 AIR QUALITY MODELING 30
5.2 IMPACT ON CLASS I AREAS 32
5.3 CLASS II ANALYSIS 32
5.4 GEORGIA AIR TOXICS GUIDELINE 33

6.0 ADDITIONAL IMPACT ANALYSIS **33**

7.0 EXPLANATION OF PERMT CONDITIONS **34**

7.1 SECTION 3.0 REQUIREMENTS FOR EMISSION UNITS 34
7.2 SECTION 4.0 REQUIREMENTS FOR TESTING 35
7.3 SECTION 5.0 REQUIREMENTS FOR MONITORING (RELATED TO DATA COLLECTION) 36
7.4 SECTION 6.0 OTHER RECORD KEEPING AND REPORTING REQUIREMENTS 36
7.5 SECTION 7.0 OTHER SPECIFIC REQUIREMENTS 36
7.6 SECTION 8.0 GENERAL PROVISIONS 36

Table I. Emissions Summary of Proposed Wood-Fired Boilers 5

Table II. Emission Limits and Operating Standards from 40 CFR 63, Subpart DDDDD 11

Table III. Performance Testing Requirements from 40 CFR 63, Subpart DDDDD 13

Table IV. Fuel Analysis Requirements from 40 CFR 63, Subpart DDDDD 14

Table V. Continuous Compliance Requirements from 40 CFR 63, Subpart DDDDD 15

Table VI. Applicable Testing Requirements 29

Table VII. Applicable Monitoring Requirements 29

Table VIII. Class II Analysis 32

SUMMARY

The Georgia Environmental Protection Division (GA EPD) has reviewed the Archer Daniels Midland application for a permit to construct and operate two new wood-fired boilers rated at 52 million British Thermal Units per hour (MMBTU/hr) of heat input generating a total 80,000 pounds per hour of process steam. Archer Daniels Midland (ADM) is located 1841 Clay Road in Valdosta, Georgia (Lowndes County).

The steam generated by the proposed wood-fired boilers will displace steam currently generated by natural gas. The steam will be used for the facility's desolventizing, toasting meal, and drying processes. The steam will also be used for building heating and cooling.

Initially, the proposed modification was to consist of a 105 MM BTU/hr wood-fired boiler. The facility, per an addendum to their application dated June 14, 2005, ADM has decided to install two (2) wood-fired boilers each with a 52 MMBTU/hr heat input rate to each generate 40,000 pounds per hour of process steam instead of the 105 MMBTU/hr boiler. The proposed boilers will be constructed in a similar manner as the 105 MMBTU/hr boiler, burn the same fuel type as the 105 MMBTU/hr boiler, and particulate matter (PM) emissions will be controlled by the ESP proposed for the 105 MMBTU/hr boiler.

The location of the facility in Lowndes County is classified as "attainment" for all regulated pollutants in accordance with Section 107 of the Clean Air Act, as amended August 1977.

The installation of the two new boilers will result in an increase in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon dioxide (CO), volatile organic compounds (VOCs), PM, and particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}). The two new boilers will result in a "significant increase emissions" for NO_X and CO.

The GA EPD review of the data submitted by Archer Daniels Midland for the construction and operation of the proposed 52 MMBTU/hr wood-fired boilers, indicates that compliance with all applicable State and Federal air quality regulations will be achieved.

It is the Preliminary Determination of GA EPD that the proposal provides for the application of best available control technology (BACT) for the control of nitrogen oxides (NOx) and carbon monoxide (CO) as required by Federal Prevention of Significant Deterioration (PSD) regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques, that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

The Preliminary Determination indicates that an Air Quality Permit should be issued to Archer Daniels Midland for the construction and operation of two 52 MMBTU/hr wood-fired boilers. Various conditions will be made a part of the permit to construct and operate in order to ensure and confirm compliance with all applicable regulations. A copy of the draft permit is provided in Appendix A.

1.0 INTRODUCTION

1.1 Prevention of Significant Deterioration Requirements

The regulations for Prevention of Significant Air Quality Deterioration (PSD) in Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR) 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply for any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or all other sources having potential emissions of 250 tons per year or more of any regulated pollutant; or modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements: 1) Application of best available control technology (BACT) for each regulated pollutant that would be emitted in significant amounts; 2) Analysis of the ambient air impact; 3) Analysis of the impact on soils, vegetation, and visibility; 4) Analysis of the impact on Class I areas; and 5) Public notification of the proposed facility modification in a newspaper of general circulation.

1.2 Proposal

On June 16, 2005, Archer Daniels Midland submitted an application for an air quality permit to construct and operate a new 105 million British Thermal Units per hour (MMBTU/hr) heat input rated wood-fired boiler to generate 80,000 pounds per hour of process steam located 1841 Clay Road in Valdosta, Georgia (Lowndes County). The steam generated by the boiler would displace steam currently generated by existing natural gas-fired boilers. The steam was to be used for the facility's desolventizing, toasting meal, and drying processes. The steam would also be used for building heating and cooling.

The proposed boiler was to be a stoker-type furnace with both water tubes and fire tubes for heat recovery-steam generation. The combustion zone of the boiler was to consist of water tubes. Various shredded wood waste materials would be used to fuel the boiler. The types of wood waste include trusses, saw dust, cotton and soybean hulls, and ground stumps and tree refuse which would be unloaded by truck at the existing truck dump. The material would then be shredded and typically have a moisture content between 10 to 50 percent. Most of the wood waste would be screw conveyed directly to the bottom of the truck dump onto an enclosed drag conveyor going to the wood waste storage silo. If the storage silo is full, then the wood waste would be sent via screw conveyor to a wood waste storage silo located adjacent to the truck dump. The wood waste pile is partially enclosed by a roof and sidewall. Wood waste in the silo would be fed to screw and belt conveyors at the bottom of the silo which transfer the wood waste to the boiler metering bins located inside the boiler house. The stoker boiler would be fed using screw conveyors that push the shredded wood waste into the stoker grate.

The stoker grate is tilted downward and the shredded wood waste combusts as it moves down toward the bottom of the furnaces riding on the gate. Air is blown up through the grate to provide combustion air. When the shredded wood waste reaches the lower end of the grate, nearly all the combustible material has been removed leaving ash and carbonized wood residue. A screw conveyor at the bottom of the furnace removes the ash from the furnace. The ash is sprayed with water, moved by covered convey to the ash building, picked up by front-end loader, and placed in a waste disposal bin. Particulate Matter (PM) would be controlled by a proposed electrostatic precipitator (ESP).

The facility, per a January 12, 2006 addendum to their application, has decided to install two (2) wood-fired boilers each with a 52 MMBTU/hr heat input capacity to each generate 40,000 pounds per hour of process steam instead of the 105 MMBTU/hr boiler. The proposed boilers will be constructed in a similar manner as the 105 MMBTU/hr boiler, burn the same fuel type as the 105 MMBTU/hr boiler, and PM emissions will be controlled by the ESP proposed for the 105 MMBTU/hr boiler.

Four external combustion boilers and one backup boiler are currently used at the facility to generate process steam. Of the five existing boilers, one is a wood waste fired boiler and the remaining four are natural gas fired boilers. Upon startup and operation of the proposed boilers, the facility proposes to use the existing wood-fired boiler and the proposed wood-fired boilers to produce necessary facility steam, and reduce the usage of the three existing natural gas-fired boilers.

The Archer Daniels Midland application and addendums to the application are included in Appendix B.

1.3 Applicability

Archer Daniel Midland's (ADM's) proposed boilers will be located at the Archer Daniel Midland Valdosta Plant located at 1841 Clay Road in Valdosta, Georgia (Lowndes County) which is classified as a PSD major source. It is not one of the 28 source categories defined in the regulation governing PSD and therefore is a major source because it has the potential to emit more than 250 tons per year of at least one PSD-regulated pollutant.

The regulated pollutants, which will be emitted in significant quantities from the boilers, are nitrogen oxides (NO_x) and carbon monoxide (CO).

The potential emissions of PSD regulated pollutants from the facility and the significant emission levels as defined by the PSD regulations are shown in Table I.

Table I. Emissions Summary of Proposed Wood-Fired Boilers

Pollutant	Potential Emissions [1] (tpy)	PSD Significant Emissions [2] (tpy)	BACT Required
NO_x	136.7	40	YES
CO	191.3	100	YES
SO_2	39.2	40	NO
PM_{10}[3]	14.3	15	NO
VOC	39.2	40	NO
Lead	0.02	0.60	NO
Fluorides	1.8	3	NO
Sulfuric Acid Mist	5.9	7	NO

1.4 Preliminary Determination

Through its new source review procedure, GA EPD has evaluated the Archer Daniels Midland's proposal for compliance with State and Federal requirements. The findings of GA EPD have been assembled in this Preliminary Determination.

2.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

2.1 State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated there under. Georgia Rules 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.03(2)(f) requires that any person operating a facility or performing activity from which air contaminants are emitted, may be required to obtain a Permit by Rule, a Generic Permit or a Part 70 Permit from the Director in addition to an operating (SIP) permit. The application submitted requests construction and operation of the boilers as provided under Georgia Rule 391-3-1-.03(7). Archer Daniels Midland is subject to

[1] Emissions are based on average ambient temperature for the boilers.
[2] Significant emission levels as defined in 40 CFR 52.21 (PSD regulations)
[3] All PM assumed to be PM_{10}.

Georgia Rule 391-3-1-.03(10)5 (iii) which requires the submittal of an application to address a significant modification. Archer Daniels Midland's Valdosta facility currently operates under Title V Operating Permit Number 2075-185-0051-V-01-0 and subsequent permit amendments. The installation of the new boilers will require a revision of the permit. The facility has submitted the applicable application forms to address the revision of Permit Number 2075-185-0051-V-01-0.

Georgia Rule 391-3-1-.02(2)(d) limits particulate emission from fuel burning equipment. Particulate emissions limit for the proposed boilers is 0.025 pounds per million British Thermal Units (lbs/MMBTU) per PSD avoidance and per the Industrial, Commercial and Institutional Boilers and Process Heaters NESHAP. Visible emissions from the proposed boilers are limited per Georgia Rule 391-3-1-.02(2)(3) to twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.

Georgia Rule 391-3-1-.02(2)(g)2 limits the fuel sulfur content of the fuels consumed in each boiler to not equal or exceed 2.5 weight percent. ADM proposes to burn a fuel blend in the boiler that has a sulfur content of 0.01 to 0.08 weight percent in order to avoid BACT requirements for emissions of SO_2. With these facts in mind, the PSD avoidance limits subsume the applicable state emission limits.

Georgia Rule 391-3-1-.03(2)(c) allows specific conditions to be added to the permit with which ADM must act in accordance with to comply with the Clean Air Act and rules and regulations. The facility must comply with emission limits established by the permit to limit sulfur dioxide (SO_2), sulfuric acid (H_2SO_4), volatile organic compounds (VOCs), and fluoride (F) emissions to remain below the applicable PSD significance levels. ADM will be required to conduct performance tests and/or fuel analysis to ensure that the facility can comply with each limitation.

2.2 Federal Rule – PSD

The regulations for Prevention of Significant Air Quality Deterioration (PSD) in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply for any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or all other sources having potential emissions of 250 tons per year or more of any regulated pollutant; or modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of best available control technology (BACT) for each regulated pollutant that would be emitted in significant amounts.

- Analysis of the ambient air impact
- Analysis of the impact on soils, vegetation, and visibility
- Analysis of the impact on Class I areas
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all PSD-regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case GA EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases, BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPSs). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose an enforceable emission standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should meet, at a minimum, two core requirements.[4] The first core requirement is that the determination follows a "top-down" approach. The second core requirement is that the selection of a particular control system, as BACT must be justified in terms of the statutory criteria and supported by the record, and must explain the basis for the rejection of other more stringent candidate control systems.

EPD's procedures for performing top down BACT analysis are detailed in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[5] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward. If the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably

[4] The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR38272.
[5] Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonderry, L.L. C., Rockingham County, New Hampshire. The U.S. EPA Region I, Air Permits Program, wrote the PSD Final Determination.

installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible. The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. Technologies in the pilot scale testing stages of development are not considered available for BACT.

Now that the PSD BACT standards have been defined, the next step is to review the remaining applicable requirements. This step will aid in citing the appropriate legal authority for each requirement in the Title V permit. This analysis will show that the PSD BACT standards represent the most stringent limit.

2.3 Federal Rule – NSPS Subpart Dc

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

Applicability: NSPS Subpart Dc is an applicable requirement for the proposed boilers because each has a heat input capacity from fuels of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr), and constructed after June 9, 1989.

Emission Standard: The allowable PM emission rate for boilers constructed after February 28, 2005 is13 ng/J (0.03 lb/MMBtu heat input). The limit is applicable to units that burn coal, oil, wood, or a mixture of these fuels with other fuels and has an annual capacity factor greater than 30 percent (0.30) for wood [40 CFR 60.43c(e)(1)1].[6]

The regulation also limits opacity from the combustion of wood as fuel to less than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity [40 CFR 60.43c(c)]. This regulation subsumes Georgia Regulation 391-3-1-.02(2)(d)(3) for PM and opacity limitations.

According to NSPS Subpart Dc, particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

The facility proposes to use an ESP to control emissions to below PSD significance levels. Per PSD avoidance and the Industrial, Commercial and Institutional Boilers and Process Heaters NESHAP, PM emissions shall be limited to 0.025 lbs/MMBTU. Therefore, the NSPS PM emission limit is subsumed by the Industrial, Commercial and Institutional Boilers and Process Heaters NESHAP and PSD Avoidance requirements.

Compliance Demonstration: Compliance with the particulate emission limit is demonstrated with an initial performance test using Method 5, Method 5B, or Method 17 [40 CFR 60.45c(a)]. Method 9 is used for determining the opacity of stack emissions [40 CFR 60.45c(a)(8)].

[6] See Federal Register Volume 71, Number 38 Monday February 27, 2006, page 9885.

This regulation also requires ADM to install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system [40 CFR 60.47c(a)]. The span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent [40 CFR 60.47c(b)]. ADM shall maintain records of opacity and submit reports of excess emissions during the reporting period [40 CFR 60.48c(c)].

The facility shall record and maintain records of the amounts of each fuel combusted during each day in each boiler [40 CFR 60.48c(g)].

ADM is required to submit notification of the date of initial startup, which shall include: the design heat input capacity of proposed boilers and identification of the fuels to be combusted in the boilers, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels if applicable, and the annual capacity factor at which the ADM anticipates operating the boilers based on all fuels fired and based on each individual fuel fired [40 CFR 60.48c(a) (1),(2), (3)]. ADM also shall submit to the Division the performance test data from the initial performance tests using the applicable performance specifications [40 CFR 60.48c(b)]. All records must be maintained for a period of two years from the date of the record [40 CFR 60.48c(i)]. The reports are to be submitted semiannually and shall be postmarked by the 30th day following the end of the reporting period. [40 CFR 60.48c(j)].

2.4 Federal Rule – NESHAP Subpart DDDDD

40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial/Commercial/Institutional Boilers and Process Heaters

Applicability: NESHAP Subpart DDDDD is an applicable requirement for the proposed boilers because they are located at a major source meeting the requirements in the final rule. The proposed 52 MMBTU/hr boilers are classified as new boilers and must in compliance with this regulation upon startup [40CFR63.7495(c)(1)]. The facility has five existing boilers that are also subject to the regulation for which compliance with the regulation must be established by September 13, 2007 [40CFR63.7495(b)].

The NESHAP defines a *large solid fuel subcategory* to include any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent [40CFR63.7575]. The proposed 52 MMBTU/hr wood-fired boilers contain both watertubes and firetubes.

On October 31, 2005 [FR Vol.70, No. 209, pp. 62264-62275], EPA proposed to amend the definitions of ‘‘firetube boiler’’ and ‘‘watertube boiler’’ in 40 CFR 63.7575 to address boilers designed with both firetubes and watertubes, commonly referred to as ‘‘hybrid boilers.’’

"We is aware of three ''hybrid boiler'' designs:
(1) Watertube boilers that incorporate a secondary firetube section to extract additional heat from the combustion gases;
(2) firetube boilers designed with watertubes that function to improve the operation and efficiency of the firetube boiler, not to increase steam generating capacity; and
(3) boilers designed with both firetubes and watertubes, in which both the firetubes and watertubes function for the purpose of steam generation.

We is proposing to classify watertube boilers that incorporate firetubes for additional heat recovery as watertube boilers for the purpose of the final rule since the unit combustion zone incorporates a watertube design. As discussed in the proposal (68 FR1671), it is the design of the boiler's combustion zone that will influence the formation of organic hazardous air pollutants (HAP) emissions and was one of the bases for creating the subcategories." [7]

The hybrid boilers' design, proposed by ADM, uses only watertubes in the combustion zone and the combustion zone design is typical of watertube boilers. The emissions are, therefore, believed to more representative of a watertube boiler rather than a firetube boiler. Therefore, the Division believes that the 10 MMBTU/hr threshold for small/large units is applicable. The proposed boilers, each with a 52 MM BTU/hr heat input rating, are determined by the Division to be new, large, solid-fuel boilers and therefore must comply with the applicable requirements prescribed by the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP. The Division believes that the preliminary determination above reflects current EPA philosophy on this issue. However, the final amendment will dictate the type classification and size threshold for hybrid boilers. The proposed permit will be modified in the event that EPA determines that the proposed hybrid boilers are not classified large boilers.

Emission Standard: This NESHAP specifies an emission standard for PM, hydrogen chloride (HCL), mercury (Hg), and carbon monoxide (CO) from the proposed boilers. Additionally, the ESP has an opacity operating limit of ten percent. Emission limits and operating standards are summarized in Table II:

[7] See Federal Register Volume 70, Number 209 Monday October 31, 2005, page 62268.

Table II. Emission Limits and Operating Standards from 40 CFR 63, Subpart DDDDD

Pollutant	Standard	Citation
PM (or TSM)	0.025 lb/MMBtu (or 0.0003 lb/MMBTU)	40 CFR 63.7500(a)(1) and Table 1 of Subpart DDDDD
HCl	0.02 lb/MMBTU	40 CFR 63.7500(a)(1) and Table 1 of Subpart DDDDD
Hg	3×10^{-6} lb/MMBTU	40 CFR 63.7500(a)(1) and Table 1 of Subpart DDDDD
CO	400 parts per million by volume on a dry basis corrected to 7% Oxygen (O_2)- three run average	40 CFR 60.7500(a)(1) and Table 1 of Subpart DDDDD
Opacity	Less than or equal to 10% (1-hour block average)	40 CFR 60.7500(a)(2) and Tables 2 and 3 of Subpart DDDDD

ADM has chosen to comply with the PM limit instead of the total selected metals (TSM) limit. Compliance demonstration discussion will involve PM only.

ADM has chosen to demonstrate compliance with the hydrogen chloride standard through fuel analysis; therefore, no discussion is provided for the health-based compliance alternative for hydrogen chloride standards associated with source testing.

Compliance with these emission limits (including operating limits) and the work practice standards in this subpart is required at all times, except during periods of startup, shutdown, and malfunction.

Compliance Demonstration:

To demonstrate initial compliance with each applicable emission limit and work practice standard, ADM may either conduct initial performance tests and establish operating limits, as applicable, according to §63.7520, paragraph (c) and Tables 5 and 7 to this subpart or conduct initial fuel analyses to determine emission rates and establish operating limits, as applicable, according to §63.7521, paragraph (d) and Tables 6 and 8 to this subpart [40CFR 63.7530 (a)]. Additionally the COMS must demonstrate acceptable operation through a performance evaluation.

Should ADM wish to demonstrate initial compliance by performance tests, it cannot establish ESP operating limits such as minimum voltage, and secondary current or total power input for particulate and mercury emissions as discussed in Table 7 of this subpart because the facility only utilizes an ESP as control for particulate emissions. An ESP must be used with additional wet scrubber control to establish ESP operating limits for particulate and mercury emissions. In addition, hydrogen chloride operating limits discussed in Table 7 of this subpart are not applicable since the facility does not employ wet or dry scrubbers for control of HCl emissions.

During the initial compliance demonstration, the specified operating parameters must be monitored during the initial performance tests that demonstrate compliance the PM, mercury, and HCl emission limits. The average parameter values measured during each test run over the three-run performances test must be calculated. The minimum or maximum of three average values, depending on the parameter measured, will establish the site-specified operating limit. If the facility wishes to conduct performance testing to show compliance with the HCl emission/operating limit, ADM must determine the average chloride content of input fuel(s) during performance testing, which will become an operating limit [40CFR63.7530(c)]. Each test run must last at least one hour.

Since ADM proposes to use fuel mixtures, all of which fuels are wood waste, in the proposed boilers, the mercury content of the inlet fuels must be determined during the mercury performance test should the facility decide to use performance testing to demonstrate compliance with the mercury emission/operating limit. The value will become the operating limit.

To demonstrate compliance with any applicable emission limit through performance testing, ADM must develop a site-specific test plan in accordance with the requirements of §63.7(c) even in the event EPA is petitioned for alternative monitoring parameters under 63.8(f) [40 CFR 63.7505(d)(1) through (4)].

Due to the size of the proposed boilers, ADM must demonstrate initial compliance with the CO emission limit by performance tests according to 40 CFR 63.7510, paragraph (c) and Table 5 of this subpart to demonstrate that average CO emissions, on a 3-run average, are at or below the limit mentioned in Table II above.

No performance tests shall be conducted during periods of startup, shutdown, or malfunction. Table III summarizes the performance tests required to demonstrate compliance with the regulation.

Table III. Performance Testing Requirements from 40 CFR 63, Subpart DDDDD

Pollutant	Required Testing	Testing Method	Citation
PM	Sampling Port Location and Traverses	Method 1 in Appendix A of Part 60	63.7520 and Table 5 of Subpart DDDDD
	Velocity and Volumetric Flow	Methods 2, 2F, or 2G in Appendix A of Part 60	63.7520 and Table 5 of Subpart DDDDD
	O_2 and CO_2 Concentrations	Method 3A of Appendix A of Part 60 or ASME PTC 19, Part 10 (1981) (§62.14(i))	63.7520 and Table 5 of Subpart DDDDD
	Moisture Content	Method 4 of Appendix A of Part 60	63.7520 and Table 5 of Subpart DDDDD
	PM emission concentration[1]	Method 5 or 17 of Appendix A of Part 60	63.7520 and Table 5 of Subpart DDDDD
	Determination of lb/MMBTU emission rate from concentration rate	Method 19 F-Factor methodology in Appendix A of Part 60	63.7520 and Table 5 of Subpart DDDDD
HCL	Sampling Port Location and Traverses	Same as PM	Same as PM
	Velocity and Volumetric Flow	Same as PM	Same as PM
	O_2 and CO_2 Concentrations	Same as PM	Same as PM
	Moisture Content	Same as PM	Same as PM
	HCL emission concentration[1]	Method 26 or Method 26A of Appendix A of Part 60	Same as PM
	Determination of lb/MMBTU emission rate from concentration rate	Same as PM	Same as PM
Hg	Sampling Port Location and Traverses	Same as PM	Same as PM
	Velocity and Volumetric Flow	Same as PM	Same as PM
	O_2 and CO_2 Concentrations	Same as PM	Same as PM
	Moisture Content	Same as PM	Same as PM
	Hg emission concentration[1]	Method 29 in appendix A of part 60 or Method 101A in Appendix B of Part 61	Same as PM
CO	Determination of lb/MMBTU emission rate from concentration rate	Same as PM	Same as PM
	Sampling Port Location and Traverses	Same as PM	Same as PM
	O_2 and CO_2 Concentrations	Same as PM	Same as PM
	Moisture Content	Same as PM	Same as PM
	CO emission concentration[2]	Method 10 or 10B of Appendix A of Part 60	Same as PM

[1]In addition to the initial performance testing requirement annual testing is required to determine compliance the applicable emission/operating limit, unless the requirements in 63.7515(b) through 63.7515(d) are followed [40CFR63.7515(a)].
[2]In addition to the initial performance testing requirement annual testing is required to determine compliance the applicable emission limit.

If the facility wishes to comply with the applicable emission/operating limits by conducting fuel analysis, then it must conduct fuel analysis according to 40 CFR 63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If ADM burns a new type of fuel, it must conduct a fuel analysis before burning the new type of fuel in the proposed boilers. ADM must still meet all applicable continuous compliance requirements in 40 CFR 63.7540 [40 CFR 63.7515(f)]. A site-specific fuel analysis plan must be developed and submitted for review and approval in accordance with 40 CFR 63.7521(b).

Table IV summarizes the fuel analysis required to demonstrate compliance with the regulation.

Table IV. Fuel Analysis Requirements from 40 CFR 63, Subpart DDDDD

Pollutant	Required Fuel Analysis	Testing Method	Citation
Hg	Collect Fuel Samples	Procedure discussed in §63.7521(c) or ASTM D6323-98 (2003) (§63.14(b)) or equivalent	63.7521 and Table 6 of Subpart DDDDD
	Composite Fuel Samples	Procedure discussed in §63.7521(d) or equivalent	63.7521 and Table 6 of Subpart DDDDD
	Prepare Composited Fuel Samples	SW-846-3050B or ASTM D5198-92 (2003) (§63.14(b)) or equivalent	63.7521 and Table 6 of Subpart DDDDD
	Determine Heat Content of Fuel Type	ASTM E711-87 (1996) (§63.14(b)) or equivalent	63.7521 and Table 6 of Subpart DDDDD
	Determine Moisture Content of the Fuel Type	ASTM D3173-02 or ASTM E871-82 (1998) (§63.14(b)) or equivalent	63.7521 and Table 6 of Subpart DDDDD
	Measure Mercury concentration of the fuel sample	SW-846-7471A	63.7521 and Table 6 of Subpart DDDDD
	Convert Concentrations into units of lbs/MMBTU		63.7521 and Table 6 of Subpart DDDDD

Table IV. Fuel Analysis Requirements from 40 CFR 63, Subpart DDDDD

Pollutant	Required Fuel Analysis	Testing Method	Citation
HCl	Collect Fuel Samples	Same as Hg	Same as Hg
	Composite Fuel Samples	Same as Hg	Same as Hg
	Prepare Composited Fuel Samples	Same as Hg	Same as Hg
	Determine Heat Content of Fuel Type	Same as Hg	Same as Hg
	Determine Moisture Content of the Fuel Type	Same as Hg	Same as Hg
	Measure chlorine concentration of the fuel sample	SW-846-9250 or ASTM E776-87 (1996) (§63.14(b)) or equivalent	63.7521 and Table 6 of Subpart DDDDD
	Convert Concentrations into units of lbs/MMBTU	Same as Hg	Same as Hg

For each continuous monitoring system (CMS) required, ADM must develop and submit to the Administrator for approval a site-specific monitoring plan at least 60 days before your initial performance evaluation of each CMS. Table V summarizes the continuous compliance requirements for the regulation [40CFR63.7505(d)(1) through (4)].

Table V. Continuous Compliance Requirements from 40 CFR 63, Subpart DDDDD

Pollutant/Operating Parameter	Required Continuous Compliance	Citation
Opacity	Collection of opacity monitoring data in accordance with §63.7525(b) and 63.7535 from a continuous opacity monitoring system (COMs) installed per PS 1 of 40 CFR part 60, appendix B.	63.7540 and Table 8 of Subpart DDDDD
	Reducing the opacity monitoring data to 6-minute averages	63.7540 and Table 8 of Subpart DDDDD
	Maintaining opacity to less than or equal 10% (1-hour block average)	63.7540 and Table 8 of Subpart DDDDD
Fuel Pollutant Content[1]	Only burn the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to 63.7530(c) or (d)	63.7540 and Table 8 of Subpart DDDDD
	Monthly[2] fuel usage records according to 63.7540(a)	63.7540 and Table 8 of Subpart DDDDD

[1]For Hg and HCl: If a new fuel type or a new mixture, other than what was burned during the initial performance test, is burned, the maximum pollutant input anticipated for the new fuels, based on supplier data or fuel analysis is required. If the pollutant content level established during the initial performance tests is exceeded, then a new performance test is required to demonstrate continuous compliance with the emission limit.

[2]NSPS Dc requires more stringent daily fuel usage records and shall subsume this requirement.

ADM must submit an initial notification within 15 days of the actual startup date [40CFR63.7545(c)] of the boilers. Notification of Intent (NOI) to conduct performance test shall be submitted at least 30 days before the performance test is scheduled to begin [40CFR63.7545(d)]. ADM must complete a notification of compliance status for each initial compliance demonstration, including all performance test results, fuel analysis, and performance evaluation, before the close of business on the 60th day following the completions of the performance test and/or other initial compliance demonstrations and must contain all the information specified in 63.7575(e)(9).

ADM must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the boilers [40CFR6375.10(g)].

ADM must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for the boilers have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550 [40 CFR 63.7515(g)].

ADM must also develop and implement a written startup, shutdown, and malfunction plan (SSMP) for each boiler according to the provisions is 40CFR63.6(e)(3).

To demonstrate compliance with reporting requirements, ADM must submit a semiannual compliance report which contains the following information:

- Information required by 65.7550(c)(1) through (11).

- If no deviations for emission limits and operating limits and no deviations from requirements for work practice standards in Table 8 of Subpart DDDDD, a statement that there were no deviations during the preparing period is required. If there were no period during which the continuous opacity monitoring system, was out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during the preparing period which the COMs was out-of-control is required.

- If there were deviations from any emission limit or operating limit, or work practices standard during the reporting period, the report must contain the information in 40 CFR 63.7550(d). If there were periods during which the COMs was out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 65.7550(e).

- If there is a startup, shutdown, or malfunction during the reporting period and actions were taken consistent with the startup, shutdown, and malfunction plan, the compliance report must include the information in 40 CFR 63.10(d)(5)(i).

The first compliance report must cover the period beginning on the compliance date and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date [40 CFR 63.7550(b)(1)]. The compliance report must be post marked or delivered no later than July 31 or January 31, whichever is earlier following the end of the first calendar half after the compliance date [40 CFR 63.7550(b)(2)]. Each subsequent report must cover the preparing period from January 1 through June 30 or July 1 through December 31 and must be post marked or delivered no later than July 31 or January 31, which date is he first date following the and of the semiannual reporting period [40 CFR 63.7550(b)(3),(4)].

An immediate startup, shutdown, and malfunction report is required if there was a startup, shutdown, or malfunction during the reporting period that is not consistent with the startup, shutdown, and malfunction plan, and any applicable emission limit in the relevant emission standard is exceeded. The actions taken for the event must be reported by fax or telephone within two (2) working days after starting actions inconsistent with the plan. The information in 63.10(d)(5)(ii) must be reported by letter within seven (7) working dates after the end of the event unless an alternative arrangement has been made with the Division. [40CFR 63.7550 (a)].

The facility shall maintain records as required by 40 CFR 63.7555 for the required time period specified in 63.7560. In addition, ADM must comply with the general provisions of 40 CFR 63.1 through 40 CFR 63.15 as specified in Table 10 of this Subpart. [40 CFR 63.7565]

2.4 Federal Rule – Compliance Assurance Monitoring (CAM)

40 CFR 64 – Compliance Assurance Monitoring

Applicability: The proposed boilers will employ an ESP to control particulate emissions, which pre-controlled, are above the major source threshold level of 100 tons per year.

Sources subject to a Federal emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Clean Air Act are exempted from the requirements of CAM [40 CFR 64.2(b)(1)(i)]. The proposed boilers are subject to the Industrial/Commercial/Institutional Boilers and Process Heaters NESHAP PM emission limit described in the previous section. The Industrial/Commercial/Institutional Boilers and Process Heaters NESHAP is a Federal regulation under section 112 of the Clean Air Act which was proposed January 13, 2003 [67FR1659].[8] Although the PM limit will be a PSD avoidance limit, it is the equivalent of the Industrial/Commercial/Institutional Boilers and Process Heaters NESHAP PM emission limit. Since the proposed PSD Avoidance limit is not going to be more stringent than the Industrial/Commercial/Institutional Boilers and Process Heaters NESHAP limit, the boilers are therefore exempted from CAM.

[8] See Federal Register Volume 68, Number 8 Monday January 13, 2003, pages 1659 through 1763.

2.5 State and Federal – Startup and Shutdown and Excess Emissions

Provisions for allowing excess emission resulting from startup, shutdown, maintenance, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the common boiler stack most likely will result during startup and shutdown. These provisions do not apply to sources subject to New Source Performance Standards (NSPS), such as these two boilers.

The NSPS Subpart Dc limits do not apply during startup, shutdown or malfunction [40 CFR 60.43c(d)]. The Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP limits do not apply during periods of startup, shutdown, and malfunction [40CFR63.7505(a)]. However, a PSD BACT limit which is the equivalent of NSPS Subpart Dc or the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP limit subsumes that limit.

Since a PSD BACT limit subsumes any NSPS Dc and Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP requirements, excess emissions of the short term (ppm or lb/MMBtu) during startup, shutdown and malfunction are not subject to the provisions in Georgia Rule 391-3-1-.02(2)(a)7. Therefore, the two boilers must comply with the BACT limitations for CO and NOx during all periods of operation, including startup, shutdown, and malfunction.

3.0 CONTROL TECHNOLOGY REVIEW

3.1 Nitrogen Oxides

Nitrogen Oxides (NO_x) are formed during the combustion of the fuel and are generally classified as either thermal NO_x, prompt NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric nitrogen is oxidized at high temperatures to yield nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen. Most thermal NO_x is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce a peak temperature. Prompt NO_x forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_x formed. Fuel-related NO_x is formed from the chemically bound nitrogen in the fuel.

There are five technologies to consider for controlling NO_x emissions from wood-fired boilers. These are combustion controls (CC), selective catalytic reduction (SCR) including SCONOx ®, Xonon®, and selective on-catalytic reduction (SCNR).

Combustion Controls for Thermal NOx – Base Option

By minimizing the amount of excess oxygen, delaying the mixing of fuel and air, and good combustions design, thermal NOx can be reduced.

Low Excess Air

With this technique, operation of the minimum excess air is optimized without excessive increase in combustible emissions. The effect of lower oxygen concentration on NOx is partially offset by some increase in thermal NOx due to the oxygen peak temperature with lower gas volume. Excess air must be present to ensure good fuel use and to prevent smoke formation.

Air Staging

With this technique, the amount of combustion air that is introduced in the primary burning zone is minimized by reducing flame temperature and oxygen availability. This introduces the final amount of combustion air above the primary combustion. For the proposed stoker boilers, air staging begins by introducing the wood waste on a grate having air blown from below the grate up through the burning wood, and by introduction of overfire-air above the grate for final burnout of combustibles. By limiting the amount of air introduced below the grate, nitrogen conversion to NOx can be minimized due to the resulting lowered flame temperatures. Final burnout air is introduced over fire-air pores above the grate.

Large Furnace Area

With this technique, a large furnace area is required to lower the peak heat release temperature in the furnace and allow sufficient residence time for final burn out of combustibles.

Combustion Controls for Fuel NOx – Base Option

Fuel NOx can be reduced by suppressing the amount of air required for complete combustion in the primary combustion zone which is the grate for the proposed stoker boilers, and by using low nitrogen fuels.

The proposed overfeed stoker boilers operate with lower oxygen levels at the grate and higher oxygen levels in the fronts, which suppresses the formation of fuel NOx. The proposed fuel, wood, has a low nitrogen content as compared to residual oil, coal and coke.

For the proposed overfeed, wood-fired stoker boilers, the combustion control techniques discussed above are collectively referred as good combustion practice, good combustion design and operation, or combustion controls.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems using ammonia (NH_3) as the reducing gas was patented in the United States by Englehard Corporation in 1957. The original catalysts, employing platinum or platinum group metals, were unsatisfactory because of the need to operate in a temperature range in which explosive ammonium nitrate forms. Other base metal catalysts were found to have low activity. Research done in Japan in response to severe environmental regulations in that country led to the development of vanadium/titanium catalysts, which have proved successful. This combination forms the basis of current SCR catalyst technology.[9]
The SCR system catalytically reduces the oxides of NO_x in flue gas to harmless nitrogen and water using NH_3 in chemical reduction. The ammonia is injected into the flue gas and mixed prior to entering the catalyst. Within the catalyst bed, the NO_x reacts with the NH_3 and are dependent on temperature. The reactions occur per the following equations.

$$NH_3 + NO \rightarrow N_2 + \frac{3}{2}H_2O$$

$$NH_3 + \frac{1}{2}NO_2 + \frac{1}{4}O_2 \rightarrow \frac{3}{2}N_2 + \frac{3}{2}H_2O$$

The catalyst formulation is the basis of the SCR system. In addition to the catalyst, the other major SCR system components include the reactor module and sealing system, NH_3 supply and injection system, and controls. The maximum NO_x removal efficiency of a SCR system is generally 80 to 90 percent. Because the reactions normally proceed at temperatures between 1,600 degrees Fahrenheit (^oF) and 1,800 ^oF, a catalyst is used to promote the reactions at lower temperatures. The use of base metal oxides, such as vanadium pentoxide, titanium dioxide, or noble metals, for both the active and support materials for the composition of the catalyst has been generally acknowledged. Newer, more sulfur-resistant ceramic catalysts have recently been used. A temperature range of 570 ^oF to 750 ^oF is typical for the reduction process, which exists before the economizers where the temperature window is approximately 500 ^oF, or before the second fire tube section were the temperature window is approximately 900 ^oF. If the catalyst bed is not located in the proper temperature zone, the reaction efficiency will be reduced if the temperature is too low, resulting in excessive ammonia slip, or the catalyst may be damaged if the temperature is too high.

[9] Discussion on the history of SCR is taken from August 1998 Report Number DOE/FETC-2000/1111 entitled Demonstration of Selective Catalytic Reduction Technology to Control Nitrogen Oxide Emissions from High-Sulfur, Coal-Fired Boilers: A DOE Assessment. The report was published by U.S. Department of Energy Office of Fossil Energy Federal Energy Technology Center Morgantown, WV/Pittsburgh, PA.

One major concern with the installation of SCR systems for the wood-fired boilers is the formation of ammonium sulfate and bisulfate upstream of the particulate control and flue gas handling equipment resulting from the reaction of NH_3 and sulfur trioxide (SO_3) in the flue gas. These are ammonia salts which will be emitted to the atmosphere as particulate matter. While ammonium sulfate is not corrosive, its formation contributes to plugging and fouling of the heat transfer system. Ammonium bisulfate is a sticky substance that deposits on the walls and heat transfer surfaces. The ammonium slag deposition could damage particulate controls and equipment.

Another concern is catalyst deactivation, the loss of active catalysis sites necessary to promote the reaction, which occurs via poisoning, fouling, thermal degradation, and mechanical losses. The SCR systems, located upstream of the ESP, could experience mechanical losses and fouling due to the high dust/particulate load in the flue gas. Permanent catalyst poisoning could result form metals and trace element in the wood.

The permit application, included in Appendix B, discusses a review of the RACT/BACT/LAER Clearinghouse (RBLC) which included an application for South Point Power to convert seven existing stoker boilers to wood–firing boilers with NOx emissions control by the installation of a hot ESP before the SCR catalysts. The permit for this modification was issued October 6, 2005, but the sources have yet to be constructed.[10] Therefore, SCR has not been demonstrated in the US for wood firing.

Another major concern with SCR technology was the high capital cost of the SCR system and the operating costs associated with periodic catalyst replacement. The overall and incremental cost effectiveness of NOx emissions reduction is $19,000 per ton. Since the catalyst could account for anywhere from 30 percent to 60 percent of the initial capital cost, the expected catalyst replacement cost (operating costs) associated with SCR technology makes this option cost prohibitive.

SCR was determined as economically and environmentally infeasible to the following reasons:

- The application of SCR on wood-fired boilers has not been demonstrated in the US.
- The poisoning effect of potassium oxides, on the catalyst acidic reactive sites is unknown.
- The overall and incremental cost effectiveness of $19,000 per ton of NOx emissions reduction is excessive.
- The increase fine particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$) resulting from the reaction of ammonia with sulfur and chloride compounds.

[10] Permit to Install Number 07-00534 issued to Biomass Energy LLC-South Point Power by the Ohio Environmental Protection Agency.

SCONOx®

SCONOx® (EMx®) is a developing technology aimed at post combustion control of multiple pollutants. The SCONOx® system is being produced by EmeraChem, LLC (formerly Goal Line Environmental Technologies) and is now called EMx®.

The EMx® system uses a coated oxidation catalyst installed in the flue gas to remove both NOx and CO without a reagent such as ammonia. The NO emissions are oxidized to NO_2 and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO_2 from the catalyst and reduce it to N_2 prior to exit from the stack. CO is oxidized to CO_2, while VOCs are oxidized to CO_2 and water, before exiting the stack.

EMx® prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO_2 is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.[11]

There is evidence that SCONOx® technology has been applied to gas fired combustion turbines. However, evidence that this technology has been applied to solid fuel fire combustion systems cannot be located.[12]

In addition, SCONOx® catalysts are susceptible to sulfur poisoning; only exhaust gases containing virtually no SO_2 can be treated. SCOSOx® technology has been developed to remove low levels of SO_2 in exhaust gas as a catalysts poison guard to the SCONOx® Catalyst. However, this process has not been applied to exhaust gas streams containing significant amounts of SO_2, as in the case of the proposed wood-fired boilers. Therefore, SCONOx technology is considered technically infeasible as NOx control technology for the proposed boilers.

[11] Discussion taken from *Grays Harbor energy LLC Satsop Combustion Turbine Project Best Available Control Technology Analysis – August 2005*.
[12] *Multi-Pollutant Emission Reduction Technology for Stationary Gas Turbines and IC Engines*. Revision 1, January 5, 2004. SCONOx White Paper – r1.

Xonon®

Catalytica Energy Systems' Xonon Cool Combustion® system improves the combustion process by lowering the peak combustion temperature to reduce the formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies (such as water injection and dry low NO_x burners) cannot provide. Most gas turbine emission control technologies remove air contaminants from exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the Xonon® system is a partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame (i.e., at relatively low temperature) to produce a hot gas. A homogeneous combustion region is located immediately downstream where the remainder of the fuel is combusted.

The key feature of the Xonon® combustion system is a proprietary catalytic component, called the Xonon Module, which is integral to the gas turbine combustor. Xonon combusts the fuel without a flame, thus eliminating the peak flame temperatures that lead to NOx formation.[13]

Xonon® is an innovative technology that is designed to be applied to gas turbines firing natural gas and is not being developed to combust solid fuels such as wood or wood waste.[14] Therefore, Xonon® technology is considered technically infeasible as NOx control technology for the proposed boilers.

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SCNR) is a post-combustion process that consists of a reagent injection system, which uses NH_3 or urea. Urea injection is commonly known as NOxOUT®. The overall reactions to reduce NOx to nitrogen and water vapor are similar to the SCR reactions. However, SNCR involves the injection of NH_3 into high-temperature regions of the boiler to reduce NOx without the use of a catalyst. A catalyst is not necessary to support the reaction of NH_3 and NO at flue gas temperatures in the range of 1,400 ^oF and 2,000 ^oF. Above 2,000 ^oF to 2,200 ^oF, NH_3 is oxidized to NO, and below 1,400 ^oF, the NOx reduction reaction stops. NOx reduction performance is maximized in the temperature window of 1,600 ^oF to 1,900 ^oF.

[13] Discussion taken from *Grays Harbor energy LLC Satsop Combustion Turbine Project Best Available Control Technology Analysis – August 2005*.

[14] http://www.catalyticaenergy.com/xonon/commercialization.html, accessed on March 7, 2006.

One major concern is that SCNR is sensitive to flue gas temperature. The furnace sections of the proposed stoker boilers are located between the grate and the flue gas passage into the fire-tube section of the boilers, where flue gas temperatures change when there is a change in boiler load, fuel characteristics, and combustion air temperature flow. Because of this variability the flue gas at the reagent injection point will not always be at the optimum temperature of NOx reduction, resulting in NH_3 slip or react with SO_3 to form ammonium salts, or incorporated in the ash. The temperature rate for the proposed furnace section is in the range of 1,000 ^oF to 2,000 ^oF. As a result, the proposed boilers will not be able to achieve the NOx reductions to levels of up to 70 percent reduction using SNCR. In addition, during startup period and lower operating loads, SNCR cannot be used due to low furnace temperatures.

In addition, complete mixing of the reagent with the flue gas can be difficult because of the relative small volume of the furnace that is at the correct temperature for SNCR reagent injection. To ensure proper mixing, the proposed stoker boilers a computational fluid dynamic modeling and a testing program will be required to optimize NOx reduction and minimize ammonia slip. Given temperature and mixing issues, SNCR cannot consistently achieve NO_x control efficiencies comparable to a SCR system, this technology is therefore considered to be technically infeasible for the proposed boilers.

Application of SNCR is combustor/fuel-specific since the technology is temperature and mixing dependant. NOx and NH_3 emission levels achievable for one boiler will not necessarily translate to the same NOx and NH_3 emission levels achievable on a different type of boiler using different fuels. The location oat various loads of the desired SNCR temperature window for the proposed stoker boilers is unknown at this time. Indiviutal boilers will exhibit unique performance characteristics which directly affect the ability of an SNCR system to meet a required NOx limit cost effective, and without unduly restricting boiler operation due to increase maintenance outages. The performance of the proposed boiler can only be established through actual operation to establish an achievable NOx emission rate and averaging period without significant negative environmental (increased opacity and sulfate particulate emissions and economic (ammonia consumption and maintenance) impacts.

SCNR is determined as technically, economically and environmentally infeasible for the following reasons:

- The NOx reduction level and resulting emission rate are unknown and will not be known until operating data is available for analysis.

- The overall and incremental cost effectiveness of $11,000 per ton of NOx emissions reduction is excessive.

- The increase $PM_{2.5}$ resulting from the reaction of ammonia with sulfur and chloride compounds.

Summary of Control Technology

After reviewing the above information, there are only two technically feasible NO_x control technologies available for boilers – combustion controls with an emission limit of 0.30 pounds of NOx per million British Thermal Units (lbs NOx/MMBTU) or SCR used in conjunction with combustion controls with an emission limit of 0.30 lbs NOx/MMBTU. A permit has been issued in EPA Region 5 instituting SCR with an ESP as a BACT for NOx. However, the permitted sources have not been constructed, and therefore there are no examples of SCR technology successfully demonstrated for wood-fired boilers. Proposed BACT for the ADM project includes combustion controls with an emission limit of 0.30 lbs NOx/MMBTU at the combined or stack exit. A cost effectiveness analysis for SCR is detailed in the application for comparison.

Conclusions for NO_x

EPD has determined that the proposal to use a good combustion with an emission limit of 0.30 lbs NOx/MMBTU to meet the requirements of BACT. This NOx BACT limit applies during all periods of boiler firing, including startup, shutdown, and malfunction.

SCR was determined as economically and environmentally infeasible to the following reasons:

- The application of SCR on wood-fired boilers has not been demonstrated in the US.

- The poisoning effect of potassium oxides, on the catalyst acidic reactive sites is unknown.

- The overall and incremental cost effectiveness of $19,000 per ton of NOx emissions reduction is excessive.
- The increase fine particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$) resulting from the reaction of ammonia with sulfur and chloride compounds.

SCONOx® was determined as technically infeasible to the following reasons:

- The application of SCONOx® on wood-fired boilers has not been demonstrated in the US.

- The poisoning effect of sulfur, on the catalyst sites with gas streams having significant amounts of SO_2.

Xonon® was determined as technically infeasible to the following reasons:

- The application of Xonon® on wood-fired boilers has not been demonstrated in the US.

- Xonon® is an innovative technology that is designed to be applied to gas turbines firing natural gas and is not being developed to combust solid fuels such as wood or wood waste.

SCNR is determined as technically, economically and environmentally infeasible for the following reasons:

- The NOx reduction level and resulting emission rate are unknown and will not be known until operating data is available for analysis.

- The overall and incremental cost effectiveness of $11,000 per ton of NOx emissions reduction is excessive.

- The increase $PM_{2.5}$ resulting from the reaction of ammonia with sulfur and chloride compounds.

3.2 Carbon Monoxide

Carbon Monoxide emissions will be emitted from the boilers as a result of incomplete fuel combustion. Incomplete combustion also leads to emissions of PM and HAPs.

Care must be taken when incorporating design changes to reduce both NOx and CO emissions. CO emission combustion modifications can possibly increase NOx emissions and vice versa. A balance between these air pollutants must be achieved in order for combustion modification to be useful.

NSPS Subpart Dc does not specify CO emission limits. The Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP, however does specify a CO emission limit discussed in Section 2.4 above to provide the most stringent level for CO emissions.

ADM reviewed two BACT alternatives; namely catalytic oxidation post combustion control and efficient combustion, which is a direct result of the design and operation of the proposed boilers.

Good Combustion Practice (GCP)- Base Option

EPD considers GCP as technically feasible and achievable in practice for the boilers in question. ADM proposed a baseline CO BACT at the stack exhaust of approximately 0.48 lbs CO/MMBTU. However, given the emission limit established by the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP, the CO BACT must be 400 ppm as seven percent O_2.

Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with a platinum or rhodium. The catalyst grid is placed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. An acceptable catalyst operation range is 450 ^{o}F to 1,100 ^{o}F. To achieve this temperature range for the proposed boilers, the catalysts would need to be installed in each boiler before the second fire tube section. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion byproducts to carbon dioxide. The active component of most catalytic oxidation systems is platinum metal, which has been applied over a metal or ceramic substrate.

The primary limitation that may preclude the use of catalytic oxidation is catalyst poisoning and deactivation by sulfur containing compounds in the flue gas. EPD believes that catalytic oxidation is technically feasible and achievable in practice for the proposed modification. This determination is based on the issuance of a permit to South Point Power for the installation of boilers discussed under SCR control. As previously discussed, the proposed boilers have yet to be constructed. Therefore, there is no technical demonstration of the catalytic oxidation in the US.

Based on the permit application, EPD has found that cost effectiveness values of $10,000/ton and higher of CO removed have been deemed “not cost effective.” ADM estimated a cost effectiveness of $15,000/ton.

With this in mind, EPD is not inclined to establish catalytic oxidation as BACT in this case since the facility must comply with the emission limit established by the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP and because of the cost effectiveness.

Conclusions for Carbon Monoxide

The Division has determined that ADM's proposal to use proper combustion design meets the requirements of BACT with exception to the proposed emission limit. Per 40 CFR Subpart DDDDD, CO emissions will be limited to 400 ppm as seven percent O_2 at the combined or stack exit. This CO BACT limit applies during all periods of boiler firing, including startup, shutdown and malfunction.

4.0 TESTING AND MONITORING REQUIREMENTS

Each boiler is subject to BACT requirements for NOx and CO. The BACT limits for CO, are equivalent to Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP limit, and shall therefore follow the requirements of the NESHAP.

ADM will be required to conduct initial performance testing only for NOx to verify compliance with the proposed BACT limit. In addition, the facility shall establish the maximum wood waste firing rate, nitrogen content of the fuel, and heat value required to comply with the BACT limit. A NOx emission factor in terms of pounds of pollutant per ton of fuel burned shall be determined for each boiler during such testing.

ADM shall conduct a total of three (3) performance tests. The performance tests shall be conducted for the following operating scenarios: one of the proposed two boilers operating independently, the second of the proposed two boilers operating independently, and both operating concurrently. The performance testing shall be conducted at maximum load for both boilers using the worst-case proposed fuel blend. In the event, however, ADM makes any changes to the operation including but not limited to the fuel blend fired in either boiler, the facility must conduct performance testing by applicable methods. The facility will also be required to establish new emission factors.The facility will also be required to report the results of the testing. The reporting frequency shall be based on the requirements established by 40 CFR 60 Subpart Dc and/or 40 CFR 63 Subpart DDDDD for CO and 40 CFR 70 for NOx.

In addition, the general provisions of NSPS and Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP provide avenues to obtain permission to use alternative testing and monitoring protocols, and in some cases, to waive testing requirements, when justified. Due to the direct correlation of NOx and CO emissions, the Division requires that NOx and CO performance demonstrations be conducted simultaneously. The table below illustrates the individual applicable testing requirements for the proposed project:

Table VI. Applicable Testing Requirements

Pollutant	Boilers NSPS Dc	Boilers Industrial/Commercial/ Industrial Boilers and Process Heaters NESHAP	Stack PSD Avoidance	Stack PSD
CO	No testing required.	Method 10 or 10B	No testing required.	Method 10 or 10B
NO_x[1]	No testing required.	No testing required.	No testing required.	Method 7 or 7E

[1]During the initial performance testing, the facility shall establish the maximum wood waste firing rate, fuel nitrogen content, heat value and NOx emission factor.

ADM will be required to monitor the daily wood waste fire rate for comparison to the performance testing established wood waste firing rate. This shall be accomplished by existing daily fuel usage monitoring already required by NSPS and Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP. This parameter along with the baseline nitrogen content in the fuel derived from testing will be used to demonstrate good combustion controls for NOx control.

The table below summarizes the individual monitoring requirements of the applicable regulations.

Table VII. Applicable Monitoring Requirements

Pollutant	Boilers NSPS Dc	Boilers Industrial/Commercial/ Industrial Boilers and Process Heaters NESHAP	Combined Stack PSD Avoidance	Combined Stack PSD
CO	No monitoring required.	No monitoring required.	No monitoring required.	No monitoring required.
NO_x	No monitoring required.	No monitoring required.	No monitoring required.	Daily wood waste firing rate[1]

[1]Accomplised by already established daily fuel usage monitoring.

The monitoring requirements for the boilers are specified in Condition No. 5.1.1, 5.2.1, and 5.2.2.

5.0 AMBIENT AIR QUALITY REVIEW

5.1 Air Quality Modeling

An air quality analysis is required of the ambient impacts associated with the construction and operation of the proposed modification. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, SO_2, Ozone (O_3), and lead (Pb). PSD increments exist for SO_2, NO_2, and PM_{10}.

A separate air quality analysis is required for each pollutant to be emitted in a significant amount over the PSD significant threshold. As shown in Table 1, CO and NOx are to be emitted in amounts over their respective PSD significant thresholds. Thus, an air quality analysis must be performed for these air pollutants.

Compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations) and the modeled ambient impact caused by the applicant’s proposed emission increase and associated growth. It is important to note that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed. The impacts of the proposed project are lower than the significance levels, therefore is no requirement to perform NAAQS modeling.

The first step in this air quality analysis is to estimate the ambient concentrations that will result from the proposed modification. Dispersion models are the primary tools used to estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations must demonstrate compliance with the applicable NAAQS or PSD increments.

In analyzing the air quality impact from the boilers, three levels of modeling were conducted:

- Air quality screening, or significant impact analysis, to evaluate only the potential emission increase of the new boiler. Only the area immediately surrounding the ADM facility was evaluated in the screening analysis. The resultant concentrations were compared to the PSD Class I significant impact levels and the ambient monitoring de minimis levels. Since insignificant NOx and CO impacts were calculated, no further refined air quality analysis was performed.

- Evaluation of air toxic emissions from the ADM facility. Total facility emissions for benzene, formaldehyde, acrolein and lead were modeled. Results were compared to the EPD's Acceptable Ambient Concentrations (AACs) for toxic air pollutants. Results of the modeling demonstrate that total facility emissions will not result in concentrations that exceed levels designed to protect public health and welfare.

- Long-range transport analysis using the CALPUFF model. The analysis was performed to evaluate whether the proposed new boilers could result in a significant Class I impact or cause an adverse visibility at the Class I areas closest to the ADM facility.

A detailed discussion of the conducted modeling is included in the permit application in Appendix B.

The dispersion models are based upon the assumption that the dispersion of pollutants is primarily a function of: wind speed and direction; atmospheric stability conditions; and the effective point of discharge of the exhaust plume. To predict ambient air concentrations, the models simulate the plume exhausting from the stack: rising a certain distance in the atmosphere, leveling off, and continuing downwind over relatively flat terrain. The concentrations of pollutants are assumed to have a Gaussian distribution about the longitudinal centerline of the plume.

In performing the modeling, the stack height input may not exceed "good engineering practice" (GEP) stack height. This constraint is based on EPA's policy of restricting dispersion enhancement credit where stacks exceed GEP. GEP is defined as the greater of 65 meters or: $HG = H + 1.5L$

where: HG = Good engineering practice stack height
H = Height of nearby structure
L = Lesser of dimension (height or width) of nearby structure

The modeling of the boilers was performed using actual stack height since the stack exceeded GEP requirements. Building wake effects (downwash) have been observed to affect plume dispersion and therefore plume impact. The dispersion modeling performed by EPD takes building wake effect into account.

5.2 Impact on Class I Areas

PSD review requires that sources located within 100 kilometers of a Class I area be evaluated for possible impact on that area. The Okefenokee National Wildlife Refuge is located 64 kilometers (40 miles) east of the ADM facility. St. Mark's National Wildlife Refuge is located 104 kilometers (64 miles) south west of ADM; and Bradwell Bay Wilderness Area is located 140 kilometers (87 miles) south west of ADM Valdosta. A long-range transport analysis was performed to demonstrate that the proposed project will not result in ambient impacts in excess of Class I significant levels for NOx or the Class I deposition analysis thresholds for nitrogen. In addition, the analysis demonstrates that the project does not have the potential to adversely impact visibility at the Class I areas. EPD has concluded that the proposed facility will not have a significant impact on any Class I areas.

Modeling was originally conducted based on the 105 MMBTU/hr boiler venting to one stack. Nitrogen oxides emissions from the two proposed 52 MMBTU/hr boilers, which will be vented to the common modeled stack, were later modeled at 25 percent, 50 percent, 75 percent, and 100 percent operating loads. Modeling demonstrated a decrease in the potential for low operating capacities to cause offsite concentrations of NOx in excess of the NOx Significance level. Modeling of the two proposed boilers was deemed acceptable by the Division.

5.3 Class II Analysis

The first analysis is to run the dispersion model only using the proposed emission rates from the proposed boilers, and the results of this analysis are compared to the PSD significant impact levels (SILs) and the de minimis concentrations for preconstruction monitoring. The following table illustrates the results of the modeling analysis.

Table VIII. Class II Analysis

Pollutant	**Averaging Period**	**Preconstruction Monitoring Evaluation (ug/m^3)**	**PSD Significant Impact Level (ug/m^3)**	**Projected Concentration (ug/m^3)**
CO	8 hour 1 hour	575 No 1 hour	500 2,000	30.97 65.63
NO_2	Annual	14	1	0.97

Predicted concentrations from the modeling study were below the de minimis preconstruction monitoring concentrations for the applicable pollutants and the site. Thus, no further Class II increment and NAAQS modeling was required.

5.4 Georgia Air Toxics Guideline

There are no applicable NAAQS or specific Georgia ambient air standards for the non-criteria pollutants being emitted, such as HAPs. Impacts from each of the pollutants listed in this letter were analyzed using the EPD Guidance for Ambient Impact Assessment of Toxic Air Pollutant Emissions (referred to as the Georgia Air Toxics Guideline; Version June 21, 1998). The Georgia Air Toxics Guideline is a guide for estimating the environmental impact of sources of toxic air pollutants. A toxic air pollutant is defined as any substance, which may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. The ISCST3 computer dispersion model was used to predict the maximum 24-hour average ground level concentration (referred to as MGLC) for each pollutant in question. EPD used the high end point of the HAP emission factor range to perform the toxic guideline assessment. Each MGLC is compared to its respective acceptable ambient concentration (referred to as AAC). The basis for calculation of the AAC comes from the pollutant toxicity rating systems described in the Georgia Air Toxics Guideline. Based on EPD's analysis, the predicted MGLC's for each applicable pollutant is below the Georgia EPD AACs. A table of air toxic modeling results is provided in Appendix C of this preliminary determination.

The project also is subject to an additional impacts analysis that assesses the impacts of air pollution on soils and vegetation caused by emissions of regulated pollutants from the project, and from associated growth in the project vicinity.

6.0 ADDITIONAL IMPACT ANALYSIS

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of the operation of the proposed boilers and an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the facility. Other impact analysis requirements may also be imposed on a permit applicant under local, State or Federal laws, which are outside the PSD permitting process.

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles – usually in the form of volatile organics, nitrogen oxides, or sulfur oxides – absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light into the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

For PSD sources, the principal visibility impacts of concern are impacts on the visibility conditions within the nearest PSD Class I area. The CALPUFF visibility analysis indicated that the maximum model change in extinction is less than five percent. Therefore, the proposed project does not have the potential to significantly alter visibility at the Class I areas.

Class II visibility impacts analysis was also performed. A Level-1 analysis was performed using EPA's VISCREEN model for both Valdosta Regional Airport and Moody Air Force Base. Such analysis requires inputs of emission rates (PM and NOx), regional visual range, distance between the source and the object of study, and worst-case dispersion parameters.

The results of the Level-1 analysis indicates that the proposed new boiler project will not impact visibility of Moody Air force Base; however exceedences occurred for the Valdosta Regional Airport. Therefore, a more refined Level-2 VISCREEN analysis was performed which resulted in the determination that the proposed boilers project will not impact visibility at the Valdosta Regional Airport.

One indicator of potential vegetation and soils effects is a comparison of predicted ambient concentrations with ambient air quality standards. Of most significance, here is the fact that the secondary NAAQs were established to prevent adverse "welfare" effects such as direct damage to vegetation and harmful contamination of soils. In light of the fact that it has been shown that the operation of the proposed boilers will not threaten or exceed any ambient standard at any location, there should not be any discernible effects on vegetation and soils.

The labor force at the ADM-Valdosta facility is approximately 57,000. The proposed boilers project will not impact population in the Valdosta metropolitan statistical area or local area. No significant impact on local air quality conditions is expected that might otherwise accompany significant population growth. Personnel used to operate the proposed boilers will most likely be drawn from the existing labor force at ADM-Valdosta, with unappreciable changes in traffic or other growth associated parameters.

7.0 EXPLANATION OF PERMT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 2075-185-0051-V-01-6.

7.1 Section 3.0 Requirements for Emission Units

Permit Conditions 3.2.11 through, 3.2.16 provide PSD avoidance limits for the applicable pollutants discussed in Section 2.1. Section IV of the narrative associated with Permit Amendment No. 2075-185-0051-V-01-6 discusses the permit conditions in more detail.

Permit Condition 3.3.5 was added to define the applicability of NSPS Dc. Permit Condition 3.3.6 was added to define the applicability of the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP.

Permit Condition 3.3.7 defines the equipment: the proposed boilers, ESP and common stack, which are subject to PSD requirements.

Permit Conditions 3.3.8 through 3.3.13 list the emission limits established by the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP and BACT.

To ensure compliance with applicable emission limits established by Permit Conditions 3.3.8 through 3.3.13, Permit Condition 3.3.14 requires the operation of ESP at all times the proposed boilers are in operation.

A table summarizing each permit condition in Section 3.0 can be located in Section IV of the narrative associated with Permit Amendment No. 2075-185-0051-V-01-6.

7.2 Section 4.0 Requirements for Testing

Permit Condition 4.1.3 was modified to include general testing requirements for the proposed boilers.

Permit Conditions 4.2.8 and 4.2.9 provide the specific testing requirements and testing schedule to demonstrate compliance with the PSD avoidance limits for the applicable pollutants discussed in Section 2.1. Permit Conditions 4.2.10 through 4.2.13 require establishment of applicable emission factors in terms of pounds of pollutant emitted per ton of fuel burned.

Permit Conditions 4.2.14, 4.2.15, 4.2.16 defines the compliance demonstration alternatives for total HCl and Hg emission limits, defines the performance testing schedule for performance testing, and defines the fuel analysis schedule for fuel analysis, respectively. Permit Conditions 4.2.17 and 4.2.18 define compliance demonstration methods for PM and CO, respectively.

Permit Conditions 4.2.19 and 4.2.20 define the compliance demonstration method for the NOx emission limit and requires establishment of an emission factor in terms of pounds of pollutant emitted per ton of fuel burned, respectively. Permit Condition 4.2.21 requires simulations performance testing for CO and NOx.

Permit Condition 4.2.22 requires an initial performance test for the COMs. Permit Condition 4.2.23 requires that the facility to establish wood waste fuel rate, nitrogen content of the fuel, and heat value to demonstrate compliance with NOx limits.

Section V of the narrative associated with Permit Amendment No. 2075-185-0051-V-01-6 lists discusses the permit conditions in more detail as well as provides a summary table of all permit conditions included in Section 4.0 of the draft permit.

7.3 Section 5.0 Requirements for Monitoring (Related to Data Collection)

The monitoring requirements, established for the boilers by the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP and NSPS Dc are specified in Condition No. 5.1.1, 5.2.1, and 5.2.2 as discussed in Section 4.0 of this document above. Permit Conditions 5.2.1 and 5.2.2 were existing permit conditions which are modified to address the proposed project.

Section VI of the narrative associated with Permit Amendment No. 2075-185-0051-V-01-6 discusses the permit conditions in more detail as well as provides a summary table of all permit conditions included in Section 5.0 of the draft permit.

7.4 Section 6.0 Other Record Keeping and Reporting Requirements

Permit Condition 6.1.7 was modified to address exceedances and excursions associated with the proposed project. The facility must maintain records required by the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP and NSPS Subpart Dc. Therefore, new conditions, listed in Section VII of the narrative associated with Permit Amendment No. 2075-185-0051-V-01-6, were added to address the requirements discussed above in Sections 2.0 and 4.0 of this document.

Section VII of the narrative associated with Permit Amendment No. 2075-185-0051-V-01-6 discusses the permit conditions in more detail as well as provides a summary table of all permit conditions included in Section 6.0 of the draft permit.

7.5 Section 7.0 Other Specific Requirements

Permit Condition 7.14.1 was added to allow the modification of Permit Number 2075-185-0051-V-01-0 in the event that EPA determines that the proposed hybrid boilers (Source Code: B115A and B115B) are to be classified as small units under the Industrial/Commercial/Industrial Boilers and Process Heaters NESHAP discussed in Section 2.0 of this document above.

7.6 Section 8.0 General Provisions

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution. Permit Condition 8.14.4 was added to address excess emissions.

APPENDIX A

Draft PSD Permit Archer Daniels Midland-Valdosta

APPENDIX B

Archer Daniels Midland PSD Permit Application and Supporting Data

Contents include:

1. PSD permit application no. 16260 dated June 14, 2005 and associated addendums

2. Criteria and HAP Emissions Review

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
SO_2	8.60E-02	PSD Avoidance	4.472	3.917E+04	19.587	8.944	7.835E+04	39.175
NO_x	3.00E-01	BACT Limit/Stack Testing[1]	15.600	1.367E+05	68.328	31.200	2.733E+05	136.656
$PM_{10\ (filterable)}$	1.50E-02	ESP Vendor Guarantee	0.780	6.833E+03	3.416	1.560	1.367E+04	6.833
$PM_{10\ (total)}$	2.50E-02	MACT Standard	1.300	1.139E+04	5.694	2.600	2.278E+04	11.388
CO	4.20E-01	MACT Standard[2]	21.840	1.193E+05	95.659	43.680	3.826E+05	191.318
VOC	8.60E-02	PSD Avoidance	4.472	3.917E+04	19.587	8.944	7.835E+04	39.175
Acenaphthene	9.10E-07	AP-42[3]	4.732E-05	0.415	2.073E-04	9.464E-05	0.829	4.145E-04
Acenaphthylene	5.00E-06	AP-42[3]	2.600E-04	2.278	1.139E-03	5.200E-04	4.555	2.278E-03
Acetaldehyde	8.30E-04	AP-42[3]	0.043	378.082	0.189	0.086	756.163	0.378
Acetone	1.90E-04	AP-42[3]	9.880E-03	86.49	0.043	0.020	173.098	0.087
Acetophenone	3.20E-09	AP-42[3]	1.664E-07	1.458E-03	7.288E-07	3.328E-07	2.915E-03	1.458E-06
Acrolein	3.15E-05	More Representative Value	1.643E-03	14.349	7.174E-03	3.276E-03	28.698	0.014
Anthracene	3.00E-06	AP-42[3]	1.560E-04	1.367	6.833E-04	3.120E-04	2.733	1.367E-03
Benzaldehyde	8.50E-07	AP-42[3]	4.42E-05	0.39	1.94E-04	8.840E-05	0.774	3.872E-04
Benzene	4.20E-03	AP-42[3]	0.218	1.913E+03	0.957	0.437	3.826E+03	1.913
Benzo(a)anthracene	6.50E-08	AP-42[3]	3.380E-06	0.030	1.480E-05	6.760E-06	0.059	2.961E-05
Benzo(a)pyrene	2.60E-06	AP-42[3]	1.352E-04	1.184	5.922E-04	2.704E-04	2.369	1.184E-03

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Benzo(a)fluoranthene	1.00E-07	AP-42[3]	5.200E-06	0.046	2.278E-05	1.040E-05	0.091	4.555E-05
Benzo(e)pyrene	2.60E-09	AP-42[3]	1.352E-07	1.184E-03	5.922E-07	2.704E-07	2.369E-03	1.184E-06
Benzo(g,h,i)perylene	9.30E-08	AP-42[3]	4.836E-06	0.042	2.118E-05	9.672E-06	0.085	4.236E-05
Benzo(j,k)fluoranthene	1.60E-07	AP-42[3]	8.320E-06	0.073	3.644E-05	1.664E-05	0.146	7.288E-05
Benzo(k)fluoranthene	3.60E-08	AP-42[3]	1.872E-06	0.016	8.199E-06	3.744E-06	0.033	1.640E-05
Benzoic Acid	4.70E-08	AP-42[3]	2.444E-06	0.021	1.070E-05	4.888E-06	0.043	2.141E-05
Bis(2-Ethylhexyl)phthalate	4.70E-08	AP-42[3]	2.444E-06	0.021	1.070E-05	4.888E-06	0.043	2.141E-05
Bromomethane	1.50E-05	AP-42[3]	7.800E-04	6.833	3.416E-03	1.560E-03	13.666	6.833E-03
2-Bututanone (MEK)	5.40E-06	AP-42[3]	2.808E-04	2.460	1.230E-03	5.616E-04	4.920	2.460E-03
Carbazole	1.80E-06	AP-42[3]	9.360E-05	0.820	4.100E-04	1.872E-04	1.640	8.199E-04
Carbon Tetrachloride	4.50E-05	AP-42[3]	2.340E-03	20.498	0.010	4.680E-03	40.997	0.020
Chlorine	7.90E-04	AP-42[3]	4.108E-02	3.599	0.180	8.216E-02	719.722	0.0360
Chlorobenzene	3.30E-05	AP-42[3]	1.716E-03	1.503	7.516E-03	3.432E-03	30.064	0.015
Chloroform	2.80E-05	AP-42[3]	1.456E-03	1.275	6.377E-03	2.912E-03	25.509	0.010
Chloromethane	2.30E-05	AP-42[3]	1.196E-03	1.048	5.238E-03	2.392E-03	20.954	1.048E-02
2-Chloronaphthalene	2.40E-09	AP-42[3]	1.248E-07	1.093E-03	5.466E-07	2.496E-07	2.186E-03	1.093E-06
2-Chlorophenol	2.40E-08	AP-42[3]	1.248E-06	0.011	5.466E-06	2.496E-06	0.022	1.093E-05
Chrysene	3.80E-08	AP-42[3]	1.976E-06	0.017	8.655E-06	3.952E-06	0.035	1.731E-05

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Crotonaldehyde	9.90E-06	AP-42[3]	5.148E-04	4.510	2.255E-03	1.030E-03	9.019	4.510E-03
Decachlorobiphenyl	2.70E-10	AP-42[3]	1.404E-08	1.23E-04	6.150E-08	2.808E-08	2.460E-04	1.230E-07
Dibenzo(a,h)anthracene	9.10E-09	AP-42[3]	4.732E-07	4.15E-03	2.073E-06	9.464E-07	8.290E-03	4.145E-06
1,2-Dibromoethene	5.50E-05	AP-42[3]	2.860E-03	25.054	1.253E-02	5.720E-03	50.107	0.025
Dichlorobiphenyl	7.40E-10	AP-42[3]	3.848E-08	3.37E-04	1.685E-07	7.696E-08	6.742E-04	3.371E-07
1,2-Dichloroehtane	2.90E-05	AP-42[3]	1.508E-03	13.210	6.605E-03	3.016E-03	26.420	0.013
Dichloromethane	2.90E-04	AP-42[3]	0.015	132.101	0.066	0.030	264.202	0.132
1,2-Dichloropropane	3.30E-05	AP-42[3]	1.716E-03	15.032	7.516E-03	3.432E-03	30.064	0.015
2.4-Dinitrophenol	1.80E-07	AP-42[3]	9.360E-06	0.082	4.100E-05	1.872E-05	0.164	8.199E-05
Ethylbenzene	3.10E-05	AP-42[3]	1.612E-03	14.121	7.061E-03	3.224E-03	28.242	1.412E-02
Fluoranthene	1.60E-06	AP-42[3]	8.320E-05	0.729	3.644E-04	1.664E-04	1.458	7.288E-04
Fluorene	3.40E-06	AP-42[3]	1.768E-04	1.549	7.744E-04	3.536E-04	3.098	1.549E-03
Fluoride	4.00E-03	PSD Avoidance	0.208	1.822E+03	0.911	0.416	3.664E+03	1.822
Formaldehyde	4.40E-03	AP-42[3]	0.299	2.004E+03	1.002	0.458	4.099E+03	2.004
Heptachlorobiphenyl	6.60E-11	AP-42[3]	3.432E-09	3.006E-05	1.503E-08	6.864E-09	6.013E-05	3.006E-08
Hexachlorobiphenyl	5.50E-10	AP-42[3]	2.860E-08	2.505E-04	1.253E-07	5.720E-08	5.011E-04	2.505E-07

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Hexanal	7.00E-06	AP-42[3]	3.640E-04	3.189	1.594E-03	7.280E-04	6.377	3.189E-03
Heptachlorodibenzo-p-dioxins	2.00E-09	AP-42[3]	1.040E-07	9.110E-04	4.555E-07	2.080E-07	1.822E-03	9.110E-07
Heptachlorodibenzo-p-furans	2.40E-10	AP-42[3]	1.248E-08	1.093E-04	5.466E-08	2.496E-08	2.186E-04	1.093E-07
Hexachlorodibenzo-p-dioxins	1.60E-06	AP-42[3]	8.320E-05	0.729	3.644E-04	1.664E-04	1.458	7.288E-04
Hexachlorodibenzo-p-furans	2.80E-10	AP-42[3]	1.456E-08	1.275E-04	6.377E-08	2.912E-08	2.551E-04	1.275E-07
Hydrogen Chloride	1.90E-02	AP-42[3]	0.988	8.655E+03	4.327	1.976	1.731E+04	8.655
Indeno(1,2,3,c,d)pyrene	8.70E-08	AP-42[3]	4.524E-06	0.040	1.982E-05	9.048E-06	0.079	3.963E-05
Isobutyraldehyde	1.20E-05	AP-42[3]	6.240E-04	5.466	2.733E-03	1.248E-03	10.932	5.466E-03
Methane	2.10E-02	AP-42[3]	1.092	9.566E+03	4.783	2.184	1.913E+04	9.566
2-Methylnaphthalene	1.60E-07	AP-42[3]	8.320E-06	0.073	3.644E-05	1.664E-05	0.146	7.288E-05
Monochlorobiphenyl	2.20E-10	AP-42[3]	1.144E-08	1.002E-04	5.011E-08	2.288E-08	2.004E-04	1.002E-07
Naphthalene	9.70E-05	AP-42[3]	5.044E-03	44.185	0.022	0.010	88.371	0.044
2-Nitrophenol	2.40E-07	AP-42[3]	1.248E-05	0.109	5.466E-05	2.496E-05	0.219	1.093E-04
4-Nitrophenol	1.10E-07	AP-42[3]	5.720E-06	0.050	2.505E-05	1.144E-05	0.100	5.011E-05
Octachlorodibenzo-p-dioxins	6.60E-08	AP-42[3]	3.432E-06	0.030	1.503E-05	6.864E-06	0.060	3.006E-05

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Octachlorodibenzo-p-furans	8.80E-11	AP-42[3]	4.576E-09	4.009E-05	2.004E-08	9.152E-09	8.017E-05	4.009E-08
Pentachlorodibenzo-p-dioxins	1.50E-09	AP-42[3]	7.800E-08	6.833E-04	3.416E-07	1.560E-07	1.367E-03	6.833E-07
Pentachlorodibenzo-p-furans	4.20E-10	AP-42[3]	2.184E-08	1.913E-04	9.566E-08	4.368E-08	3.826E-04	1.913E-07
Pentachlorobiphenyl	1.20E-09	AP-42[3]	6.240E-08	5.466E-04	2.733E-07	1.248E-07	1.093E-03	5.466E-07
Pentachlorophenol	5.10E-08	AP-42[3]	2.652E-06	0.023	1.162E-05	5.304E-06	0.046	2.323E-05
Perylene	5.20E-10	AP-42[3]	2.704E-08	2.369E-04	1.184E-07	5.408E-08	4.737E-04	2.369E-07
Phenanthrene	7.00E-06	AP-42[3]	3.640E-04	3.189	1.594E-03	7.280E-04	6.377	3.189E-03
Phenol	5.10E-05	AP-42[3]	2.652E-03	23.23	1.162E-02	5.304E-03	46.463	0.023
Propanol	3.20E-06	AP-42[3]	1.664E-04	1.46	7.288E-04	3.328E-04	2.915	1.458E-03
Propionaldehyde	6.10E-05	AP-42[3]	3.172E-03	27.787	0.014	6.344E-03	55.573	2.779E-02
Pyrene	3.70E-06	AP-42[3]	1.924E-04	1.685	8.427E-04	3.848E-04	3.371	1.685E-03
Styrene	1.90E-03	AP-42[3]	0.099	865.49	0.433	0.198	1.731E+03	0.865
Sulfuric Acid Mist	1.30E-02	PSD Avoidance	0.676	5.922E+03	2.961	1.352	1.184E+04	5.922
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.60E-12	AP-42[3]	4.472E-10	3.917E-06	1.959E-09	8.944E-10	7.835E-06	3.917E-09
Tetrachlorodibenzo-p-dioxins	4.70E-10	AP-42[3]	2.444E-08	2.141E-04	1.070E-07	4.888E-08	4.282E-04	2.141E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	9.10E-11	AP-42[3]	4.732E-09	4.145E-05	2.073E-08	9.464E-09	8.290E-05	4.145E-08

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Tetrachlorodibenzo-p-furans	7.50E-10	AP-42[3]	3.900E-08	3.416E-04	1.708E-07	7.800E-08	6.833E-04	3.416E-07
Tetrachlorobiphenyl	2.50E-09	AP-42[3]	1.300E-07	1.139E-03	5.694E-07	2.600E-07	2.278E-03	1.139E-06
Tetrachloroethene	3.80E-05	AP-42[3]	1.976E-03	17.310	8.655E-03	3.952E-03	34.620	0.017
o-Toualdehyde	7.20E-06	AP-42[3]	3.744E-04	3.280	1.640E-03	7.488E-04	6.559	3.280E-03
p-Tolualdehyde	1.10E-05	AP-42[3]	5.720E-04	5.011	2.505E-03	1.144E-03	10.021	5.011E-03
Toluene	9.20E-04	AP-42[3]	0.048	419.078	0.210	0.096	838.157	0.419
Trichlorobiphenyl	2.60E-09	AP-42[3]	1.352E-07	1.184E-03	5.922E-07	2.704E-07	2.369E-03	1.184E-06
1,1,1-Trichloroethane	3.10E-05	AP-42[3]	1.612E-03	14.121	7.061E-03	3.224E-03	28.242	0.014
Trichloroethene	3.00E-05	AP-42[3]	1.560E-03	13.666	6.833E-03	3.120E-03	27.331	0.014
Trichlorofluoromethane	4.10E-05	AP-42[3]	2.132E-03	18.676	9.338E-03	4.264E-03	37.353	0.019
2,4,6-Trichlorphenol	2.20E-08	AP-42[3]	1.144E-06	0.010	5.011E-06	2.288E-06	0.020	1.002E-05
Vinyl Chloride	1.80E-05	AP-42[3]	9.360E-04	8.199	4.100E-03	1.872E-03	16.399	8.199E-03
o-Xylene	2.50E-05	AP-42[3]	1.300E-03	11.3388	5.694E-03	2.600E-03	22.776	0.011
Total Organic Compounds	3.90E-02	AP-42[3]	2.028	17,765.28	8.883	4.056	3.553E+04	17.765
Nitrous Oxide	1.30E-02	AP-42[3]	0.676	5,921.76	2.961	1.352	1.184E+04	5.922
Carbon Dioxide	1.95E+02	AP-42[3]	1.014E+04	8.883E+07	4.441E+04	2.028E+04	1.777E+08	8.883E+04

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Antimony	7.90E-06	AP-42[3]	4.108E-04	3.599	1.799E-03	8.216E-04	7.197	3.599E-03
Arsenic	2.20E-05	AP-42[3]	1.144E-03	10.021	5.011E-03	2.288E-03	20.043	0.010
Barium	1.70E-04	AP-42[3]	8.840E-03	77.438	0.039	0.018	154.877	0.077
Beryllium	1.10E-06	AP-42[3]	5.720E-05	0.501	2.505E-04	1.144E-04	1.002	5.011E-04
Cadmium	4.10E-06	AP-42[3]	2.132E-04	1.868	9.338E-04	4.264E-04	3.735	1.868E-03
Chromium, total	2.10E-05	AP-42[3]	1.092E-03	9.566	4.783E-03	2.184E-03	19.132	9.566E-03
Chromium, hexavalent	3.50E-06	AP-42[3]	1.820E-04	1.594	7.972E-04	3.640E-04	3.189	1.594E-03
Cobalt	6.50E-06	AP-42[3]	3.380E-04	2.961	1.480E-03	6.760E-04	5.922	2.961E-03
Copper	4.90E-05	AP-42[3]	2.548E-03	22.320	0.011	5.096E-03	44.641	0.022
Iron	9.90E-04	AP-42[3]	0.051	450.965	0.225	0.103	901.930	0.451
Lead	4.80E-05	AP-42[3]	2.496E-03	21.865	0.011	4.992E-03	43.730	0.022
Manganese	1.60E-03	AP-42[3]	0.083	728.832	0.364	0.166	1.458E+03	0.729
Mercury	3.50E-06	AP-42[3]	1.820E-04	1.594	7.972E-04	3.640E-04	3.189	1.594E-03
Molybdenum	2.10E-06	AP-42[3]	1.092E-04	0.957	4.783E-04	2.184E-04	1.913	9.566E-04
Nickel	3.30E-05	AP-42[3]	1.716E-03	15.032	7.516E-03	3.432E-03	30.064	0.015

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

BOILERS COMBUSTION EMISSIONS (PTE)

Boiler Heat Input:	52	MMBTU/Hr
Hours of Operation:	8,760	hrs/yr
Pounds Per Ton:	2,000	lbs/ton

Pollutant	Emission Factor (lb/MM BTU)	Basis of Emission Factor	Emissions (per boiler)			Emissions (both boilers)		
			(lbs/hr)	(lbs/yr)	(TPY)	(lbs/hr)	(lbs/yr)	(TPY)
Phosphorus	2.70E-05	AP-42[3]	1.404E-03	12.299	6.150E-03	2.808E-03	24.598	0.012
Potassium	3.90E-02	AP-42[3]	2.028	1.777E+04	8.883	4.056	3.553E+04	17.765
Selenium	2.80E-06	AP-42[3]	1.456E-04	1.275	6.377E-04	2.912E-04	2.551	1.275E-03
Silver	1.70E-03	AP-42[3]	0.088	774.384	0.387	0.177	1.549E+03	0.774
Sodium	3.60E-04	AP-42[3]	0.019	163.987	0.082	0.037	327.974	0.164
Strontium	1.00E-05	AP-42[3]	5.200E-04	4.555	2.278E-03	1.040E-03	9.110	4.555E-03
Tin	2.30E-05	AP-42[3]	1.196E-03	10.477	5.238E-03	2.392E-03	20.954	0.010
Titanium	2.00E-05	AP-42[3]	1.040E-03	9.110	4.555E-03	2.080E-03	18.221	9.110E-03
Vanadium	9.80E-07	AP-42[3]	5.096E-05	0.446	2.232E-04	1.019E-04	0.893	4.464E-04
Yttrium	3.00E-07	AP-42[3]	1.560E-05	0.137	6.833E-05	3.120E-05	0.273	1.367E-04
Zinc	4.20E-04	AP-42[3]	0.022	191.318	0.096	0.044	382.637	0.191

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

[1]NOx Emissions (lbs/ MMBTU) = Cd x Fd x [20.9 / (20.9 - $\%O_2$)]
Cd (ppm) = [NOx Emissions (lbs/ MMBTU) x (20.9 - $\%O_2$)] / [Fd x 20.9 x Cf]
NOx Emissions (lbs/ MMBTU) = Cd x Fd x [20.9/20.9-$\%O_2$] x Cf
NOx Emissions (lbs/ MMBTU) = 138 ppm x 9,600 dscf/MMBTU x [20.9/(20.9-10.3)] x (1.194 x 10^{-7} ppm/[lbs/scf])
NOx Emissions (lbs/ MMBTU) = 0.30 lbs/MMBTU

Where:

Cd = Three Run Average NOx emissions (ppm) from July 2002 Stack Test Data for Existing Wellons Boiler.
$\%O_2$ = $\%O_2$ from July 2002 Stack Test Data for Existing Wellons Boiler.
Cf = Conversion Factor for NOx
Fd = F-Factor for wood bark.

[2]CO Emissions (lbs/ MMBTU) = Cd x Fd x [20.9 / (20.9 - $\%O_2$)]
Cd (ppm) = [CO Emissions (lbs/ MMBTU) x (20.9 - $\%O_2$)] / [Fd x 20.9 x Cf]
CO Emissions (lbs/ MMBTU) = Cd x Fd x [20.9/20.9-$\%O_2$] x Cf
CO Emissions (lbs/ MMBTU) = 400 ppm x 9,600 dscf/MMBTU x [20.9/(20.9-7)] x (7.27 x 10^{-8} ppm/[lbs/scf])
CO Emissions (lbs/ MMBTU) = 0.42 lbs/MMBTU

Where:

Cd = MACT emission standard.
$\%O_2$ = $\%O_2$ from MACT emission standard.
Cf = Conversion Factor for CO
Fd = F-Factor for wood bark.

[3]Wet Bark AP-42 factors used.

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

Emission Rate Calculations:

Emissions (lbs/hr) = Maximum Firing Rate (MMBTU/hr) x Emission Factor (lbs/MMBTU)
Emissions (lbs/yr) = lbs/hr x 8,760 hrs/year
Emissions (TPY) = lbs/yr x (1/2,000 lbs/ton)
$\text{Emission Rate}_{\text{two boilers}} = \text{Emission Rate}_{\text{one boiler}} \times 2$

Abbreviations:

MMBTU = Million British Thermal Units
BTU = British Thermal Units
lbs = pounds
hr = hour
TPY = tons per year

NOTE: PM controlled by a ESP.

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

FUGITIVE PM EMISSIONS (WASTE HANDLING SYSTEM)

Determination of Emission Factors:

Truck Dump (lbs/ton) = $0.0032*((U/5)^{1.3})/((M_T/2)^{1.4})$
Truck Dump (lbs/ton) = 1.52E-05 lbs/ton

Ash Loader Dump (lbs/ton) = $0.0032*((U/5)^{1.3})/((M_A/2)^{1.4})$
Ash Loader Dump (lbs/ton) = 3.87E-05 lbs/ton

Where:

U =	2	mph due to enclosures/buildings
M_T =	39.00	% for composite fuel
M_A =	20.00	% for ash due to water spray

Increased Truck Traffic (no sweeping) [lbs/VMT] = k*((sL/2)^0.65)8((W/3)^1.5-C*((1-(P/4/N)))
Increased Truck Traffic (no sweeping) [lbs/VMT] = 1.67 lbs/VMT

Where:

k =	0.016	for PM-10
sL =	7.4	for mun. landfill see page 13.1-11 of AP-42
W =	40	(80,000/2,000) per email from Kevin Caudle (4/7/05)
C =	4.70E-04	for PM-10 see page 13.2 1-5 of AP-42
P =	120	days of precipitation/yr see page 13.2 1-8 of AP-42
N =	365	for annual

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

FUGITIVE PM EMISSIONS (WASTE HANDLING SYSTEM)

PM Emission Factors:

Truck Dump (partial enclosure) =	1.52E-05	lb/ton
Ash Loader Dump =	3.87E-05	lb/ton
Increased Truck Traffic (no sweeping) =	1.67	lbs/VMT
Silo Feed Conveyor =	0	completely closed
Silo Vent =	0	negligible due to slow rate of air displacement
Silo Transfer to Conveyor =	0	completely closed
Silo Dump to Feeder Bins =	0	completely closed
Partially Coverage Storage =	0	partially enclosed, use truck dump emissions

PM Emission Source	Emission Factor	Conversion Factor	Emissions lbs/hr	lbs/yr	TPY
Increased Truck Traffic (no sweeping) =	1.67	0.4	0.668	5,852	2.926
Truck Dump (partial enclosure) =	1.52E-05	10	1.52E-04	1.331	0.001
Silo Feed Conveyor =	NA	NA	0	0	0
Silo Vent =	NA	NA	0	0	0
Silo Transfer to Conveyor =	NA	NA	0	0	0
Silo Dump to Feeder Bins =	NA	NA	0	0	0
Partially Coverage Storage =	NA	NA	1.52E-04	1.331	0.001
Ash Loader Dump =	3.87E-05	0.1	3.87E-06	0.034	1.70E-05
		TOTAL =	0.668	5,854	2.927

ADM PSD APPLICATION 16260
EMISSION ESTIMATES REVIEW

FUGITIVE PM EMISSIONS (WASTE HANDLING SYSTEM)

NOTES:

PM Emissions (lbs/hr) = Emission Factor x Conversion Factor
PM Emissions (lbs/yr) = PM Emissions (lbs/hr) x 8,760 hrs/yr
PM Emissions (TPY)= PM Emissions (lbs/yr) / 2,000 lbs/ton

Increased Truck Traffic (no sweeping) Conversion Factor = 0.4 VMT/hour see page 13.2 1-4 of AP-42
Truck Dump (partial enclosure) Conversion Factor = 10 ton/hr see page 13.2 4-3 of AP-42

Ash Loader Dump Conversion Factor = 0.1 ton/hr see page 13.2 4-3 of AP-42

APPENDIX C

EPD's PSD Dispersion Modeling and Air Toxics Assessment Review

REQUEST FOR MODELING ANALYSIS

I. ENGINEERING INPUT

- Engineer Requesting: T Tate
- Emissions/Process Reviewed By: T Tate
- Project type(s): PSD √ ; Toxics √ ; Quarry________; BART_____
- Permit Reference Number: 2075-185-0051-V-01-6

A. Source Information

- Facility Name (Engr.): ADM - Valdosta
- Location(City &/or County (Engr): Valdosta/Lowndes
- Criteria Pollutants emitted in significant amounts (Engr: tpy):

PROJECT:	NOx	138	PLANT-WIDE:	NOx	248
	SO2	39		SO2	79.8
	PM10	14.5		PM10	94.4
	CO	221		CO	________
	VOC	39		VOC	______
	SAM	6.9		SAM	7.3
	Fl	2.9		Fl	________
	Pb	0.55		Pb	________

- Date emission data verified 2/20/06 (Engr.)
- Is data provided sufficient to accurately inventory the PSD Increment? No
- Attach plot plan of the facility that shows property lines, building
- locations and emission points, & receptor locations.
- **ATTACH MODELING CD OR FILES!**

B. Background Information

- PSD baseline dates: SO_2 4/8/81 PM10 4/8/81 NO_2 1/13/05
- Modeling to be conducted for: PSD Increment Class I√, Class II√
  NAAQS √, Preconstruction monitoring √, BART Visibility_________
- If there are Class I areas within 200 km of the source, OR if Q/D > 4, where
  Q= tpy of visibility-affecting pollutants, and D= facility-to-Class I
  Area distance (km): distance to OK,STM,BB area(s) is 64,104, & 140 km.
- Is modeling to include fugitive emissions: No (Yes/No)? If yes,
  are fugitive emissions adequately characterized in report? No (Yes/No)?
- If any actual stack height is less than its GEP stack height, attach BPIP
  model output table (provided by applicant).
  Are emission rates modeled allowable limits? Yes
- Periods of operation if other than 24 hours/day, 7 days/week:
  Source Code __________ Hours per day _____ Days per week _________
- Are complex terrain issues identified or considered in the report? Yes
- If VOC emissions are to increase by more than 100 tpy, is an ozone impacts
  analysis included in the applicant's report? NA
- Are Class II visibility issues addressed? Yes
- Are additional impacts (soil, vegetation, & growth) addressed? Yes
- Remarks or additional information: ____

II. INITIAL {Significance Test} MODELING RESULTS **(project emissions only!)**

- Date completed 03/02/06 By PSC

TABLE II-1 PROJECT IMPACTS VS. SIGNIFICANCE LEVEL **(CLASS I AREAS)**

Criteria Pollutant	Averaging Period	Significance Level ($\mu g/m^3$)	Maximum* Project Concentration ($\mu g/m^3$)	Receptor UTM Zone: 17		Model Met Data Period
				X(m)	Y(m)	[yymmddhh]
SO_2	Annual	0.1	NA			
	24-Hour	0.2	NA			
	3-Hour	1.0	NA			
PM10	Annual	0.2	NA			
	24-Hour	0.3	NA			
NO_2	Annual	0.1	0.00474	367752	3383592	1983

*Highest concentration - = ALL averaging periods

TABLE II-2 PROJECT IMPACTS VS. SIGNIFICANCE LEVEL **(CLASS II AREAS)**

Criteria Pollutant	Averaging Period	Significance Level ($\mu g/m^3$)	Maximum* Project Concentration ($\mu g/m^3$)	Receptor UTM Zone: 17		Model Met Data Period
				X(m)	Y(m)	[yymmddhh]
SO_2	Annual	1	NA			
	24-Hour	5	NA			
	3-Hour	25	NA			
PM10	Annual	1	NA			
	24-Hour	5	NA			
NO_2	Annual	1	0.9676	285000	3412300	1986
CO	8-Hour	500	30.97	284700	3412700	86010816
	1-Hour	2000	65.63	284900	3412400	82032707

*Highest concentration - = ALL averaging periods

-IF MAXIMUM PROJECTED CONCENTRATION EXCEEDS THE SIGNIFICANCE LEVEL FOR ANY AVERAGING PERIOD, NAAQS ANALYSIS IS REQUIRED FOR THAT POLLUTANT.
The Class I maximum NO_2 concentration was modeled at the Okeefenokee Class I area.

Source ADM, Valdosta

TABLE II-3 PROJECT POLLUTANT MONITORING *DE MINIMIS* IMPACTS

Pollutant	Avg. Period	De Minimus Concentration ($\mu g/m^3$)	Projected* Concentration ($\mu g/m^3$)	Receptor UTM Zone 17 X(m)	Receptor UTM Zone 17 Y(m)	Model Met Data Period (yymmddhh)
CO	8-Hour	575	30.97	284700	3412700	86010816
NO_2	Annual	14	0.9676	285000	3412300	1986
PM10	24-Hour	10	< Significant emission rate			
SO_2	24-Hour	13	< Significant emission rate			
Pb	3-Month	0.1	< Significant emission rate			
Hg	24-Hour	0.25	< Significant emission rate			
Be	24-Hour	0.001	< Significant emission rate			
Fl	24-Hour	0.25	< Significant emission rate			
Vinyl Chloride	24-hour	15	< Significant emission rate			
Total Reduced S	1-Hour	10	< Significant emission rate			
H_2S	1-Hour	0.2	< Significant emission rate			
Reduced S Compounds	1-Hour	10	< Significant emission rate			

*Highest concentration off property

- AUTOMATIC EXCLUSION FROM PRECONSTRUCTION MONITORING IF PROJECTED CONCENTRATION LESS THAN *DE MINIMUS* Yes (Yes/No)
- Model(s) used: ISC-Prime version 04269
- Meteorological data: Year(s)'82-'86 Surface data from Savannah
- Upper air data from Waycross
- Remarks or additional information: Monitoring *de minimis* concentrations of pollutants with significant emission rates are all less than their respective, prescribed threshold concentrations. Therefore, no monitoring need be required.

III. FINAL MODELING RESULTS – PSD INCREMENT

Source ADM, Valdosta

TABLE III-1 **CLASS I AREA** INCREMENT ASSESSMENT- ALL RELEVANT SOURCES

Pollutant	Averaging Period	Allowable Increment (µg/m³)	Maximum* Increments Consumed (µg/m³)	Receptor UTM Zone17		Model Met Data Period
				X(m)	Y(m)	(yymmddhh)
SO_2	Annual	2	< Significant emission rate			
	24-Hour	5	< Significant emission rate			
	3-Hour	25	< Significant emission rate			
PM10	Annual	4	< Significant emission rate			
	24-Hour	8	< Significant emission rate			
NO_2	Annual	2.5	0.00474	367752	3383592	1983

*Off property concentrations:
Highest concentration: annual averaging periods
Highest, second highest concentration: 24-hour and 3-hour averaging periods

- Models used: ISC-Prime 04269
  - Meteorological data: Year(s) 1982-86
  - Surface data from Tallahassee
  - Upper air data from Waycross
- Fugitive emissions included in model? No, less than Significant emission rate.
- Remarks or additional information: The long-term Significance modeling results are used to reflect Class I modeling was necessary. The NO_2 concentration above has not incorporated the NOx Ambient Ration mitigation factor.

TABLE III-2 **CLASS II AREA** PSD INCREMENT ASSESSMENT, ALL RELEVANT SOURCES
Source ADM, Valdosta

Pollutant	Averaging Period	Allowable Increment (µg/m^3)	Maximum* Increments Consumed (µg/m^3)	Receptor UTM Zone 17 X(m)	Receptor UTM Zone 17 Y(m)	Model Met Data Period (yymmddhh)
SO_2	Annual	20	< Significant emission rate			
	24-Hour	91	< Significant emission rate			
	3-Hour	512	< Significant emission rate			
PM10	Annual	17	< Significant emission rate			
	24-Hour	30	< Significant emission rate			
NO_2	Annual	25	0.9676	285000	3412300	1986

*Off property concentrations:
Highest concentration: annual averaging periods
Highest, second highest concentration: 24-hour and 3-hour averaging periods

- Models used: ISC-Prime version 04269
  - Meteorological data: Year(s) 1982-86
  - Surface data from Tallahassee
  - Upper air data from Waycross
- Fugitive emissions included in model? No
- Remarks or additional information: Only the new boiler contributes to this increment consumption since no other pollutants for which an increment has been promulgated modeled to show concentrations in excess of their significance threshold concentrations. Note this is below the Monitoring De Minimis concentration for NO_2.

IV. Final Modeling Results - National Ambient Air Quality Standards (NAAQS)
Source ADM, Valdosta

TABLE IV-1 PROJECTED IMPACT - NAAQS

Pollutant	Averaging Period	All Source Impact (µg/m^3)	Total* Impact (w/bkgrd) (µg/m^3)	NAAQS (µg/m^3)	Receptor UTM Zone 17 X (m)	Receptor UTM Zone 17 Y (m)	Model Met Data Period (yymmddhh)
SO_2	Annual	NA	NA	80			
	24-Hour	NA	NA	365			
	3-Hour	NA	NA	1300			
PM10	Annual	NA	NA	50			
	24-Hour	NA	NA	150			
NO_2	Annual	NA	NA	100			
CO	8-Hour	NA	NA	10,000			
	1-Hour	NA	NA	40,000			
Pb	3-Month	NA	NA	1.5			

*Total impact equals source impact, plus impact from offsite sources, plus background

Background Concentrations (m**g/m^3**)

Averaging Period	**SO_2**	**PM10**	**NO_2**	**CO**
Annual	8.1	20	14	-
24-Hour	51	38	-	-
8-Hour	-	-	-	1000
3-Hour	115	-	-	-
1-Hour	-	-	-	1160

- Origin(s) of other sources' emission data:
  Actual emissions _____ Allowable emissions NA, if yes has data been verified _____? Engineering review _____ Other _______________
  - Have other sources been checked for GEP stack height? No need.
  - Was actual X or GEP ____ height used in the model?
- Model(s) used: ISC-Prime, version 04269
- Meteorological data: Year(s) 1982-86 Surface data from Tallahassee
  Upper air data from Waycross
- Computer summary of contributing sources attached see Disk in file (Yes/No)?
- Remarks or additional information ____

*Off-property concentrations:
Highest concentration - annual averaging periods
Highest, second highest concentration – 24-hour – to – 1 -hour averaging periods
Highest, 6th high concentration - 24-hour PM10 averaging period

Level I (VISCREEN) Analysis:

Distance (D_{vis}) beyond which facility-wide emissions are predicted to cause no plume visible impacts under worst-case (F,1) conditions: 31.579 (<50 km)

List of sensitive receptors between 1km and D_{vis} in any direction from the facility (National Parks & Class I Areas, State Parks & Historic Sites, airports, etc.):

Sensitive Receptor	Closest Distance (km)	Azimuth from facility (^{o})
Valdosta Regional Airport	5.03	205^o
Moody Air Force Base	14.634	20^o
Quitman-Brooks Co. Airport	31.579	265^o

Level II (VISCREEN) Analysis:

Determination of Worst-case 1% Cumulative Frequency condition:

Year of Met Data: Met condition (ie., F,2):	1982	1983	1984	1985	1986
Valdosta Regional Airport	D,3	D,5	D,5	D,3	F,3
Moody Air Force Base	F,1				

Sensitive Receptors not passing Level II (VISCREEN) Analysis:

1. Moody AFB: In 1982, F-1 m/s conditions occur in excess of 1% of the year. This inhibits a Level-II analysis. However, the alignment of the runways at the AFB, and the location of the AFB with respect to ADM indicate that, because stable conditions can exist for no more than 1 hour at sunset, it will be rare for an E-5 condition to persist long enough to establish a stable plume over the AFB. In the morning, a southwest wind may transport a plume toward the AFB, but the sun will rise in the southeast, essentially perpendicular to the orientation of such a plume. This angular relationship will not favor the visual perception of the plume.

2. Valdosta Regional Airport: In 1986, F-3 conditions were observed to persist in excess of 1% of the year. However, in the other years, D-3 conditions, or better, were observed to be the worst-case condition persisting for more than 1% of the year. The location of the airport with respect to ADM again indicates that the angular relationships of the plume and the facility locations will not favor visual plume perception in the morning hour after sunrise. In the evening, the major runway at the airport is aligned at an approximate 45-degree angle to a plume from the ADM facility which might possibly pass over the airport. An observer must be considered to be looking along the plume axis with no more than a 15-degree deviation in order for the plume to be perceptible.

Other airports in the area are more distant from the ADM facility than the Quitman-Brooks County Airport. The latter airport passed Level-1 perceptible plume analysis, and for that reason, these facilities, more distant from the ADM facility, are not anticipated to perceive a plume from the ADM facility under any condition.

Air Toxics Results:

The following air toxics concentrations are different than those submitted because the applicant incorporated building downwash effects in the submitted analysis. The Georgia Air Toxics Guideline employs Safety factors, rather than assess the effects of downwash, to assure a sufficient margin of safety for public health.

Table V-1a

Contaminant	Worst-case Annual Conc. ($\mu g/m^3$)	Long-term ACC ($\mu g/m^3$)	Worst-case 15-minute Conc.($\mu g/m^3$)	Short-term AAC ($\mu g/m^3$)
Acrolein	0.01153	0.02	0.3805	23
Benzene	0.02308	0.13	0.9455	1600
Formaldehyde	0.02556	0.77	1.0185	245

Table V-1b

Contaminant	Worst-case 24-hour Conc. ($\mu g/m^3$)	24-hour ACC $\mu g/m^3$)	Worst-case 15-minute Conc.($\mu g/m^3$)	Short-term AAC ($\mu g/m^3$)
Lead	0.02957	0.12	NA	NA

All air toxics evaluated by the applicant meet the applicable Georgia Air Toxics Guideline Acceptable Ambient Concentrations (AACs). Since these impacts are not supposed to assess downwash effects, the ISCST3 model was used in review of the air toxics concentrations.