Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

September 25, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation, Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project

Dear Mr. Raiola:

Enclosed is one copy of the draft permit for the proposed new Boiler 8 project to be installed at the existing Clewiston Sugar Mill and Refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, Administrator of the New Source Review Section, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

Trina L. Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

In the Matter of an
Application for Air Permit by:

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Authorized Representative:
Mr. William A. Raiola, V.P. of Sugar Processing Operations

Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
Clewiston Sugar Mill and Refinery
Facility ID No. 0510003
Proposed Boiler 8 Project
Hendry County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, United States Sugar Corporation, applied on April 02, 2003 to the Department for a permit to construct the proposed new Boiler 8 project at the existing Clewiston Sugar Mill and Refinery located in Hendry County Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit modification is required to perform proposed work. The Department intends to issue this air construction permit modification based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of intent to issue an air construction permit modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of the Public Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the Public Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S.

however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Permit package (including the Public Notice, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9/25/2003 to the persons listed:

Mr. William A. Raiola , USSC*
Mr. Don Griffin, USSC
Mr. Peter Briggs, USSC
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson (Clerk) September 25, 2003 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Permit No. 0510003-021-AC

U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler 8 Project
Hendry County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to U.S. Sugar Corporation (applicant) to construct the new Boiler 8 project at the existing Clewiston Sugar Mill and Refinery located in Hendry County, Florida. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is United States Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

The applicant proposes to construct a spreader stoker boiler with a maximum continuous steam production rate of 500,000 pounds per hour to support the sugar mill and refinery operations of the existing plant. The boiler will fire bagasse as the primary fuel and distillate oil as a restricted alternate fuel for startup and supplemental uses. As part of the project, existing Boiler 3 will be permanently shut down and the bagasse handling system will be modified to accommodate Boiler 8. Actual emissions of several small existing miscellaneous activities in the mill and refinery may also occur.

The existing Clewiston sugar mill and refinery is located in Hendry County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to state and federal Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following net potential increases in emissions in terms of "tons per year" (TPY): 55 TPY of carbon monoxide (CO); 0.8 TPY of fluorides (Fl); 0.1 TPY of lead (Pb); 90 pounds per year of mercury (Hg); 431 TPY of nitrogen oxides (NOx); 62 TPY of particulate matter (PM/PM_{10}); 10 TPY of sulfuric acid mist (SAM); 157 TPY of sulfur dioxide (SO_2); and 168 TPY of volatile organic compounds (VOC). Emissions of NOx, PM/PM_{10}, SAM, SO_2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

In accordance with Rule 62-212.400, F.A.C., the draft permit includes emissions standards that represent the Department's preliminary determination of the Best Available control Technology (BACT) for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

As part of the required PSD preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The air quality analysis showed no significant impacts from the project for any pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Physical Address: Suite 4, 111 S. Magnolia Drive
Mailing Address: 2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114

Florida Department of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 941/332-6975

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Project No. 0510003-021-AC
Air Permit No. PSD-FL-333
Clewiston Sugar Mill and Refinery
ARMS Facility ID No. 0510003
Proposed Boiler 8 Project

COUNTY

Hendry County

APPLICANT

United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

September 18, 2003

1. GENERAL PROJECT INFORMATION

Application Processing Schedule

01/28/03 Meeting in Tallahassee; topics included the proposed Boiler 8 project.
03/13/03 Permit engineer visited the existing facility in Clewiston to discuss the proposed Boiler 8 project.
04/01/03 Received application to construct Boiler 8.
04/02/03 Received $7500 PSD application processing fee.
04/18/03 Meeting in Tallahassee to discuss possible incompleteness issues.
04/25/03 Requested additional information.
05/02/03 Requested additional information related to air quality modeling.
05/22/03 Received additional information (partial).
05/28/03 Meeting in Tallahassee to discuss remaining additional information.
06/16/03 Written request for information discussed in 05/28/03 meeting.
07/22/03 Received additional information; application complete.

Facility Description and Location

The United States Sugar Corporation (U.S. Sugar) operates the existing Clewiston sugar mill (SIC No. 2061) and refinery (SIC No. 2062), which are located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar.

"Bagasse" is the fibrous material remaining from sugarcane after milling. It is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The primary air pollution sources currently consist of five boilers that fire bagasse and fuel oil. Particulate matter emissions are controlled with wet scrubbers for Boilers 1 through 4 and with an electrostatic precipitator for Boiler 7. Other air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, conditioning silos with dust collectors, vacuum systems, sugar/starch bins, conveyors, and a packaging system.

Regulatory Categories

Title III: The facility is identified as a potential major source of hazardous air pollutants (HAP).

Title IV: The facility operates no units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The facility is a PSD-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility operates one or more units subject to New Source Performance Standards of 40 CFR 60.

Project Description

U.S. Sugar proposes to construct a new boiler to support the sugar mill and refinery operations of the existing plant. The preliminary design for the proposed new boiler (Boiler 8) specifies a membrane wall boiler with balanced draft spreader stoker and supplemental distillate oil firing system. At the time of the application, the exact boiler specifications were being designed to provide more efficient fuel combustion than previous similar bagasse-fired boilers. The following tables summarize the preliminary boiler design specifications and fuel characteristics for the proposed project.

Table 1A. Preliminary Boiler Design

Parameter	Description
Boiler Type	Balanced draft, membrane wall, spreader stoker boiler
Primary Solid Fuel Feed	Rotating feeders and pneumatic spreaders feed bagasse onto a traveling grate at a maximum rate of approximately 130 tons per hour
Supplemental Fuel	Low NOx burners firing distillate oil with an annual capacity factor of less than 10%; preliminary design incorporates duel-fuel burners with the capacity to fire natural gas
Combustion Air	Over-fire air is provided to complete combustion and reduce NOx emissions; under-fire air is provided for combustion and to cool the traveling grate
Ash Removal	Submerged conveyor to ash pond
Heat Input Rate	1030 MMBtu/hour (1-hour maximum); 936 MMBtu/hour, continuous (24-hour maximum)
Steam Production	550,000 lb/hour (1-hour maximum); 500,000 lb/hour, continuous (24-hour maximum)
Steam Parameters	600 psig at 750° F and an enthalpy of 1379 Btu/lb
Feedwater Parameters	800 psig at 250° F with an enthalpy of 218 Btu/lb
Furnace Volume	50,520 ft^3
Heat Release Rates	20,497 Btu/ft^3 for bagasse; 11,184 Btu/ft^3 for distillate oil
Thermal Efficiency	62%
Stack Parameters	13 feet diameter (maximum); 199 feet tall (minimum)
Flue Gas	400,000 acfm at 5.5% O_2 and 330° F; (225,000 dscfm at 7% O_2 and 330° F)

Table 1B. Typical Fuel Characteristics for Boiler 8

Parameter	Bagasse (Primary Fuel)	No. 2 Distillate Oil (Startup/Supplemental Fuel)
General Information		
Density (lb/gallon)	---	6.83
Heating Value (Btu/lb)	3600, wet	19,910
Heating Value (Btu/gallon)	---	135,000
Ultimate Analysis		
Carbon	47.6%	84.7%
Hydrogen	6.0%	15.3%
Nitrogen	0.38%	0.015%
Oxygen	42.1%	0.38%
Sulfur	0.03-0.07%	0.05%
Ash/Inorganic	2.6-5.3%	0.06%
Moisture	49-55%	0.51%
Expected Maximum Firing Rates		
Heat Input Rate (MMBtu per hour), 1-hour maximum	1030	562
Heat Input Rate (MMBtu per hour), 24-hour maximum	936	562
Bagasse (tons per hour), 1-hour maximum	143	---
Bagasse (tons per day), 24-hour maximum	3120	---
Distillate Oil (gallons per hour), 1-hour maximum	---	4161
Distillate Oil (gallons per day), maximum	---	99,864

As shown above, bagasse will be fired as the primary fuel and distillate oil containing no more than 0.05% sulfur by weight will be fired as a startup and supplemental fuel. Distillate oil firing will be limited to an annual capacity factor of less than 10%. This restriction avoids specific requirements of NSPS Subpart Db. Originally, the applicant also proposed natural gas as a startup and supplemental fuel, but later withdrew the request because the supply of natural gas to this site is not expected for several years. It is noted that the preliminary design incorporates dual-fuel burners with the capacity to fire natural gas. The total annual capacity factor for Boiler 8 will be restricted to 75% by limiting the annual steam production to 3.6135 x 10^{+09} pounds per year, which is equivalent to 6,767,100 MMBtu/year. U.S. Sugar proposes the following equipment and techniques to control air emissions.

- *Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)*: CO and VOC emissions will be minimized by good combustion design and operating practices.
- *Nitrogen Oxides (NOx): NOx emissions will be reduced by installing and operating a selective non-catalytic reduction (SNCR) system to inject urea.*
- *Particulate Matter (PM/PM_{10})*: Emissions of particulate matter will be reduced by installing and operating a wet cyclone followed by a dry electrostatic precipitator.
- *Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)*: Emissions of SO_2 and SAM will be minimized by the firing of low sulfur fuels including bagasse and distillate oil ($\leq$0.05% sulfur by weight).

As part of the project, existing Boiler 3 rated at 130,000 lb/hour of steam will be permanently shut down resulting in emissions decreases. The shutdown of this unit allows the project to avoid PSD applicability for CO emissions. The project also includes slight emissions increases from small units at the sugar refinery and from the additional handling of bagasse.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-296	Emission Limiting Standards
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the following sections of the Code of Federal Regulations (CFR).

Title 40	Description
Part 60	Subpart A, General Provisions for NSPS Sources NSPS Subpart Db, Standards of Performance for Industrial–Commercial-Institutional Steam Generating Units Applicable Appendices

PSD Applicability and Preconstruction Review

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant

Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) for each regulated pollutant or areas designated as "unclassifiable" for such pollutants. A facility is considered "major" with respect to PSD if it emits or has the potential to emit:

≥ 250 tons per year of any regulated pollutant, or

≥ 100 tons per year of any regulated pollutant and belonging to one of 28 PSD Major Facility Categories, or

≥ 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates specified in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and subject to PSD preconstruction review. This means that the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each PSD-significant pollutant as well as evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, the project may be subject to PSD preconstruction review for several PSD-significant pollutants.

The existing sugar mill and refinery includes boilers with a cumulative heat input rate from fossil fuels greater than 250 MMBtu per hour, which means that it belongs to the "List of 28 PSD Facility Categories" specified in Table 62-212.400-1, F.A.C. For facilities on this list, the threshold for classification as a PSD major source is 100 tons per year. The Clewiston plant is an existing PSD major source of air pollution because the actual and potential emissions for several pollutants emitted from the plant are greater 100 tons per year. The existing plant is located in Hendry County, which is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS). As such, all new projects are reviewed for the applicability of PSD preconstruction review based on the PSD Significant Emission Rates specified in Table 62-212.400-2, F.A.C. Table 2A summarizes the applicant's PSD applicability analysis for project emissions including increases from Boiler 8, decreases from Boiler 3, and miscellaneous sources.

Table 2A. Summary of the Applicant's PSD

Pollutant	Net Increase, TPY [a]	PSD Threshold, TPY [a]	Subject to PSD Review?
CO	55	100	No [b]
NOx	431	40	Yes
PM/PM_{10}	62/58	15/25	Yes
SO_2	157	40	Yes
VOC	168	40	Yes
SAM	10	7	Yes
Lead	0.1	0.6	No
Mercury	0.05	0.1	No
Fluorides	0.8	3	No

a. "TPY" means tons per year.
b. Net CO emissions are below the PSD significant emission rate due to the shutdown of Boiler 3 as par of the project.

As shown in the table, the project is subject to PSD preconstruction review for emissions of NOx, PM/PM_{10}, SAM, SO_2, and VOC.

3. AVAILABLE INFORMATION

In addition to information provided and referenced in the application, the Department also relied on the following information.

1. EPA's Handbook titled, "Control Technologies for Hazardous Air Pollutants"; Document No. EPA/625/6-91-014; June 1991; Section 4.10, Electrostatic Precipitators
2. "Air Pollution Control Technology Handbook"; Karl B. Schnelle, Jr. and Charles A. Brown; 2002 by CRC Press LLC; ISBN 0-8493-9588-7; Chapter 24, Electrostatic Precipitators
3. EPA's Guidebook for Course #SI:412B titled, "Electrostatic Precipitator Plan Review"; Document No. EPA 450/2-82-019; July 1983; Section 3 (ESP Design Parameters and Their Effects on Collection Efficiency) and Section 4 (ESP Design Review)
4. De-NOx Technologies (DNT): Internet web site (http://www.de-nox.com/index.htm) and SNCR Proposal
5. Fuel Tech: Internet web site (http://www.fuel-tech.com/home.htm) and SNCR Proposal
6. White Paper titled "Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions"; Prepared by the SNCR Committee of the Institute of Clean Air Companies, Inc.; May 2000
7. White Paper titled "Selective Catalytic Reduction (SCR) for Controlling NOx Emissions"; Prepared by the SCR Committee of the Institute of Clean Air Companies, Inc.; November 1997

4. BOILER 8 - CONTROL TECHNOLOGY REVIEW

MACT Review

On November 26, 2002, EPA proposed Subpart DDDDD, a National Emissions Standard for Hazardous Air Pollutants (NESHAP). The proposed rule establishes maximum achievable control technology (MACT) standards to reduce hazardous air pollutant (HAP) emissions from industrial, commercial and institutional boilers and process heaters. In general, the proposed industrial boiler MACT imposes two primary performance standards: a total particulate matter emission limit of 0.026 lb/MMBtu as surrogate for the reduction of total particulate HAP; and 400 ppmvd @ 3% oxygen as a surrogate for the reduction of total organic HAP. However, the boiler would not be subject to this rule until it becomes final.

Because the above MACT rule is not yet final, the project could be subject to a case-by-case MACT determination in Section 112(g) of the Clean Air Act. The application includes estimated HAP emissions based on the results of HAP testing conducted on the Boiler 7 at the Clewiston Mill. This is a similar, large modern bagasse boiler with a maximum heat input rate of 812 MMBtu per hour. Based on the application, total potential HAP emissions are estimated to be about 14 tons per year, which is below the MACT applicability threshold of 25 tons per year. In addition, no single HAP is estimated to be greater than 10 tons per year. Therefore, the proposed project does not trigger a case-by-case MACT.

NSPS Review

The proposed new boiler is subject to the New Source Performance Standards (NSPS) in 40 CFR 60, which are adopted by reference in Rule 62-204.800(7)(b), F.A.C. Subpart Db establishes standards, testing, and monitoring provisions for emissions of nitrogen oxides, particulate matter, and sulfur dioxide primarily from industrial boilers firing coal, oil, natural gas, or wood with a maximum heat input rate of more than 100 MMBtu per hour. When firing distillate oil, the proposed boiler has a maximum heat input rate of 562 MMBtu per hour making the unit subject to the applicable Subpart Db requirements.

However, the proposed boiler will fire distillate oil containing no more than 0.05% sulfur by weight limited to an annual capacity factor of less than 10%. As such, Subpart Db establishes the following requirements:

- Sulfur Dioxide (SO_2): No specific SO_2 standards or percent reduction requirements are imposed because the unit will fire only very low sulfur oil, which is defined in the rule as $\leq$ 0.5% sulfur by weight. Compliance with the oil specification will be demonstrated by maintaining fuel receipts. [§60.42b (j) and §60.49b (r)]

- Particulate Matter (PM/PM_{10}): As specified in the rule, no particulate matter emission standard is imposed because no equipment will be necessary to reduce SO_2 emissions. The rule does limit opacity to 20% or less, except for one 6-minute block per hour not to exceed 27%. The opacity standard does not apply during startup, shutdown, or malfunction. A continuous opacity monitoring system (COMS) is required by this rule unless an alternate sampling procedure is approved by EPA. The applicant has requested an alternate monitoring procedure in lieu of the COMS. It is nearly identical to that previously approved by EPA Region 4 for Boiler 7. [§60.43b (b), (f), and (g)]
- Nitrogen Oxides (NOx): As specified in the rule, no NOx standard is imposed because the distillate oil firing is limited to an annual capacity factor of no more than 10%. [§60.44b (c)]

Therefore, the fuel sulfur specification, fuel oil annual capacity factor limit, opacity standard, and COMS are the only NSPS Subpart Db requirements applicable to the proposed boiler.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

CO and VOC are emitted as products of incomplete combustion. VOC emissions are significant and require a BACT determination. As proposed, the project did not trigger PSD review for CO emissions due to emissions decreases from the shutdown of Boiler 3, the requested CO emission standards, and the proposed capacity restrictions on Boiler 8. However, in general, the technologies used to control CO and VOC emissions from boilers are similar and will be reviewed together.

CO/VOC - Applicant's Recommendation

The applicant identified the following technologies as available for the control of CO and VOC emissions.

- *Refrigerated Condensers*: Refrigerated surface and contact condensers can be used to cool the exhaust gas and condense out organic compounds from gas streams with high concentrations (~ 5000 ppmv). These units are generally reserved for processes with organic compound concentrations that are much greater than the levels estimated for the proposed boiler (~ 100 ppmvd) and which can isolate a specific compound for reuse or resale. Refrigerated condensers were identified as not feasible for the control of VOC emissions from this project.
- *Carbon Adsorbers*: Gas streams with low flow rates and relatively high organic compound concentrations can be controlled by adsorption onto carbon particles. However, the flue gas exhaust from the proposed boiler will have a high flow rate (~ 400,000 acfm) with a predicted low VOC concentration (~ 100 ppmvd). Carbon adsorbers were identified as not feasible for the control of VOC emissions from this project.
- *Flares*: Gas streams with high concentrations of carbon monoxide and organic compounds can be combusted using specially designed burner tips and auxiliary fuel. For example, large volumes of methane gas collected from active landfills can be combusted in an open flame on an elevated flare. Again, due to the expected low concentrations of these pollutants, flares were identified as not feasible for the project.
- *Catalytic Oxidation*: The reduction of carbon monoxide and organic compounds across a catalyst bed within a given temperature range is recognized as a viable control method. This technology has been applied to reduce CO and VOC emissions from gas turbines as well as VOC emissions from coating lines and flexographic printing operations. Control efficiencies of more than 90% are possible. However, catalysts can be blinded, masked, or poisoned by contaminants in the exhaust gas stream, which can rapidly decrease the control effectiveness and lead to premature replacement. Catalytic incineration is identified as not feasible for the project due to the high uncontrolled particulate loading of the exhaust stream and the potential for catalyst poisoning from expected contaminants resulting from firing biomass.
- *Thermal Oxidation*: The thermal destruction of organic compounds at high temperatures can achieve emission reductions over 90%. However, the project is being designed for uniform fuel firing and high temperatures to provide efficient combustion. The high flue gas flow rate (~ 400,000 acfm) with predicted low concentrations of organic compounds (~ 100 ppmvd) and carbon monoxide (~ 400 ppmvd) represent

difficult design constraints. The gas stream could be split with separate thermal oxidizers firing a supplemental fuel to provide the temperature required for destruction. It is estimated that about 420 million standard cubic feet of natural gas per year would be needed as a supplemental fuel. However, this would result in emissions of additional pollutants and natural gas is not yet available to the area. Based on the predicted characteristics of the boiler flue gas, the thermal oxidation is identified as not feasible for the project.

The applicant reviewed similar industrial and electric utility biomass boiler projects listed in EPA's RACT/BACT/LAER Clearinghouse database. For the 22 projects listed, VOC emission standards ranged from 0.007 to 2.62 lb/MMBtu. The large range of emission standards are the result of differences in boiler design, operating practices, and fuels. The previous determinations were based on such control technologies identified as good combustion practices, boiler design, and overfire air. Based on a review of previous determinations for biomass boilers and the available control technologies, the applicant recommends the following VOC emission standard as BACT.

VOC $\leq$ 0.06 lb/MMBtu of heat input based on a 3-run test average

The applicant requests the following CO emission standard, which will allow the project to avoid PSD preconstruction review for CO emissions.

CO $\leq$ 0.38 lb/MMBtu of heat input, annual CEMS average

CO and VOC emissions will be minimized by proper boiler design and good combustion practices including: control of combustion air and temperature; even distribution of biomass on fuel grate; and effective control of furnace loads. The above standards would apply when firing bagasse, distillate oil, or a combination of these fuels. Compliance with the VOC standard would be determined by annual performance tests and compliance with the CO standard would be determined by data collected from a continuous emissions monitoring system (CEMS).

<u>CO/VOC - Department's Preliminary Determination</u>

Due to the high combustion temperatures, VOC emissions are predicted to be very low (~ 100 ppmv). This low concentration combined with a high flue gas flow rate (~ 400,000 acfm) makes most add on controls impractical. A review of EPA's RACT/BACT/LAER Clearinghouse database as well as other state databases for similar biomass-fired boilers did not show any cases where add on control technologies were required to reduce CO and VOC emissions from similar biomass-fired boilers. Also, EPA recently proposed Maximum Achievable Control Technology (MACT) standards for industrial boilers. The proposed MACT standards for reducing organic emissions of hazardous air pollutants (HAP) are based on the boiler design with good combustion practices and not add-on control technology. For large solid fuel-fired industrial boilers, this is represented in the proposed regulation by a work practice standard that requires CO emission levels in the boiler flue gas to be maintained at 400 ppmvd @ 3% oxygen or less based on a 24-hour average. Although the proposed MACT standard is not yet applicable to the boiler, the Department has notified the applicant that it would be prudent to design the new boiler for this critical parameter. Due to air infiltration, it is noted that the stack exhaust may contain much higher oxygen levels than the boiler flue exhaust, perhaps 5.5% oxygen in the stack compared to 3% oxygen in the boiler flue exhaust.

The Department reviewed VOC test data for similar modern bagasse-fired boilers. Test data for Clewiston's Boiler 7 shows VOC emissions ranging from 0.001 to 0.114 lb/MMBtu for six stack tests. All but the one test averaged less than 0.02 lb/MMBtu. On the day the tested VOC emission rate was 0.114 lb/MMBtu, the CO emission rate was reported as 0.392 lb/MMBtu, which may indicate that the unit was not operating under the best combustion conditions. Test data was also reviewed for New Hope Power's three 715 MMBtu/hour cogeneration boilers when firing bagasse. The tests indicate VOC emissions ranging from 0.007 to 0.02 lb/MMBtu for nine separate stack tests. This information suggests that actual VOC emissions from a newly designed bagasse-fired boiler will be less than 0.02 lb/MMBtu when adhering to good combustion practices.

In addition to bagasse, the proposed boiler will also fire distillate oil as a startup fuel and supplemental fuel. The firing of distillate oil results in a more efficient fuel combustion process with much lower VOC emissions (~ 0.0014 lb/MMBtu) than the bagasse firing. Based on the available information, the Department makes the following preliminary VOC BACT determination.

VOC $\leq$ 0.05 lb/MMBtu based on a 3-run test average at permitted capacity

The above standard is based on a modern boiler designed for efficient fuel combustion and the use of good combustion practices including the control of combustion air and temperature, even distribution of biomass on fuel grate, and effective control of furnace loads. The standard is twice the emission rate expected from a newly designed modern bagasse-fired boiler. However, it also considers fluctuations in emissions due to varying parameters such as fuel heating value and moisture content. Compliance with the standard will be demonstrated based on initial and annual compliance tests conducted in accordance with EPA Method 25A. EPA Method 18 may also be used to subtract the methane and ethane fraction of total hydrocarbons measured by EPA Method 25A.

For CO emissions, the Department will establish the following standard as a short-term limit with compliance demonstrated by initial and annual stack testing as determined by EPA Method 10.

CO $\leq$ 0.38 lb/MMBtu based on a 3-run test average at permitted capacity under steady-state conditions

This is the standard requested by the applicant, which shows the capability of the boiler to operate with low CO emissions while employing good combustion practices. To provide reasonable assurance that the project remains minor with respect to PSD, the Department will also specify the following CO standard with compliance demonstrated by data collected from a Continuous Emissions Monitoring System (CEMS) for carbon monoxide.

CO $\leq$ 1285.0 tons per consecutive 12 months including startup, shutdown, and malfunction (CEMS)

CO emissions during startups, shutdowns, and malfunctions shall be minimized to the extent possible, but all such emissions shall be included in average used to determine compliance with the above standard. In general, short-term CO emissions during such periods are not expected to exceed 4.5 lb/MMBtu. However, the air quality analysis showed no adverse impacts with a modeled 1-hour maximum emissions rate as high as 6.5 lb/MMBtu.

As indicators of adherence to good combustion practices, the draft permit will identify target ranges for the flue gas oxygen content and CO concentration. The target CO level will be identified as the proposed MACT standard of 400 ppmvd @ 3% oxygen based on a 24-hour average excluding startup and shutdown. As stated in the proposed MACT, "... [EPA] consider[s] monitoring and maintaining CO emission levels to be associated with minimizing emissions of organic HAP. Carbon monoxide is generally an indicator of incomplete combustion because CO will burn to carbon dioxide if adequate oxygen is available. Therefore, controlling CO emissions can be a mechanism for ensuring combustion efficiency and may be viewed as a kind of GCP (good combustion practice)." Therefore, the proposed work practice standard will be used as a general target by the operators to minimize CO, VOC, and organic HAP emissions. Operation outside the proposed oxygen or CO levels is not a violation in and of itself. Repeated operation beyond these levels without taking corrective actions to regain good combustion could be considered "circumvention" in accordance with Rule 62-210.700, F.A.C.

Nitrogen Oxides (NOx)

NOx emissions will result from the combustion of bagasse and distillate oil, primarily in the form of thermal NOx. NOx emissions from fuel-bound nitrogen are low because bagasse (~ 0.38% by weight) and distillate oil (~ 0.015% by weight) contain only small amounts of nitrogen. In addition, uncontrolled NOx emissions when firing bagasse are generally lower than other standard solid fuels such as coal due to the lower heating value (3600 Btu/lb, wet) and high moisture content (~ 50%), which results in a lower combustion temperature.

Applicant's NOx Review

The applicant identified the following NOx control technologies: oxidation of NOx with subsequent absorption; selective catalytic reduction (SCR); selective non-catalytic reduction (SNCR); SCONOx™; air staging; fuel staging; steam injection; flue gas re-burn (FGR); natural gas re-burn (NGR); overfire air (OFA); less excess air (LEA); combustion optimization; reduce air preheat; low NOx burners (LNB); and ultra low nitrogen fuels. The proposed boiler design will incorporate overfire air, low excess air, low nitrogen fuels, low-NOx burners for distillate oil firing, and good combustion practices. These control techniques are estimated to result in a NOx emission rate of 0.24 to 0.28 lb/MMBtu heat input without add on controls. This is about 10% to 30% higher than the New Hoper Power cogeneration boilers, which are large modern boilers that started up in 1997 and fire wood and bagasse as the primary fuels. NOx emissions are expected to be higher because Boiler 8 is being designed for high temperatures, improved combustion efficiency, and low CO emissions.

Of the remaining add on control options, several technologies have demonstrated control efficiencies as high as 80% for specific applications. The following discusses the applicant's review of each option for the bagasse-fired boiler project.

- *Oxidation of NOx with Subsequent Absorption*: Oxidants such as ozone, ionized oxygen, or hydrogen peroxide can be injected into the flue gas to oxidize nitrogen to a higher valence state, which makes NOx soluble in water. A gas scrubber can then be used to remove the NOx. A non-thermal plasma reactor can be used to generate gas-phased radicals, which oxidize NOx to form nitric acid. A wet condensing precipitator can then remove the nitric acid. The applicant rejects these technologies as technically infeasible for the project because neither has been demonstrated on large-scale boilers or bagasse combustion.
- *SCONOx™*: This technology is a proven, proprietary, and patented catalytic oxidation and absorption technology, which is recognized by the EPA as "demonstrated in practice" for the control of NOx emissions from combined cycle gas turbines. However, there are only two known applications of this technology, which are both for combined cycle gas turbine projects. The applicant rejects this technology because it has not yet been designed for, or demonstrated on, a biomass-fired boiler.
- *Selective Catalytic Reduction (SCR)*: Within an operating temperature range of approximately 600° F, ammonia could be injected prior to the air preheater. In the presence of a catalyst, ammonia will reduce NOx to nitrogen and water vapor. Although this technology has been successfully employed on coal-fired boilers, the applicant does not believe that this technology has ever been demonstrated on bagasse-fired boilers. The applicant provided supporting information indicating bagasse combustion will result in significant concentrations of several compounds recognized as strong catalyst poisons (sodium, potassium, phosphorous, and chlorides). The following table summarizes potential catalyst poisons found in ash samples taken from Clewiston Boiler 7 and compares to those for a typical coal-fired boiler.

Table 4A. Comparison of Catalyst Poisons in Ash Concentrations, Bagasse vs. Coal Combustion

Compound	Concentrations Found in Ash Samples, Percent by Weight					
	Boiler 7 (Bagasse)	Coal				
		Class "F"	Class "C"	hvBb, Utah	hvAb, Penn	hvC
Na_2O	0.3	0.1	1.9	3.8	0.4	0.6
K_2O	15.0	2.5	0.3	0.9	1.7	2.8
P_2O_5	6.2	0.1	1.1	---	---	0.1
SO_3	9.3	0.2	2.3	6.2	1.4	4.2
Chlorides	7.6	---	---	---	---	---

The applicant also provided the following statement from Halor Topsoe, a catalyst vendor, "We have looked at the data you sent and notice that the content of K in the ash is > 10%, which is twice as much as we observed in a testing on the wood fired boiler. In addition, the content of Cl is > 5%. Thus, a very large amount of KCl aerosols (a severe catalyst poison) is to be expected, which will result in a very rapid deactivation in a high dust position. I will expect that the deactivation will be so high that it is not manageable in practice." In addition, the applicant notes that the SCR catalyst could be plugged and blinded due to the high flue gas moisture content and heavy particulate loading resulting from the high dust configuration. Due to expected premature catalyst deactivation, the applicant believes that placing an SCR system directly after the boiler is inappropriate for this project.

At the request of the Department, the applicant did provide a cost analysis for an SCR system placed after the ESP called a "tail-end" or "low dust" SCR configuration. The analysis included estimated costs to reheat the flue gas to an effective SCR catalyst temperature of about 700° F using distillate oil (natural gas is not yet available in this area). Capital costs were estimated to be $5,233,569 and annualized costs including reheat were estimated at $6,476,474 per year. Assuming an 80% removal rate, the cost effectiveness is estimated at $11,840 per ton of NOx removed. The applicant rejected SCR due to technical concerns regarding catalyst poisons for the high dust SCR configuration and unreasonable costs for the low dust configuration.

- *Selective Non-Catalytic Reduction (SNCR)*: In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. The exhaust temperature must typically be maintained above 1600°F to allow the reaction to occur; otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. Also, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For biomass-fired boilers, SNCR is expected to result in control efficiencies of about 50%. Boiler operating conditions are suitable for the application of SNCR. The applicant provided information indicating that an SNCR system based on urea injection is technically feasible and cost effective.

Based on a review of the available control options, the applicant recommends the following NOx standard based on an SNCR system.

NOx ≤ 0.14 lb/MMBtu of heat input based on a 12-month rolling CEMS average excluding startup, shutdown, and malfunction

The applicant believes the long-term NOx standard is warranted for the project due to the variability of bagasse as a fuel, particularly the moisture content.

Department's Preliminary NOx BACT Determination

The Department does not completely accept the applicant's conclusion that SCR is not technically feasible. However, it is recognized that the known worldwide applications of SCR on boilers firing bagasse and wood is very limited, even more so than applications of SCR for refuse-fired plants, for which only non-U.S. applications currently exist. It is also acknowledged that premature catalyst deactivation is a concern given the presence of specific catalyst poisons found in ash generated from bagasse combustion at the existing plant. Finally, based on an estimate of more than $10,000 per ton of NOx removed for a "tail-end system", it does not appear that SCR is cost effective for this project.

EPA's RACT/BACT/LAER Clearinghouse database lists 22 biomass-fired electric utility and industrial boilers with BACT determinations ranging from 0.10 to 0.46 lb/MMBtu. Four of the listed facilities include SNCR systems with NOx standards of 0.10, 0.14, 0.15, and 0.20 lb/MMBtu. It is also noted that the New Hope Power and Palm Bach Power cogeneration plants in Florida fire a combination of wood and bagasse and employ SNCR systems with NOx emission standards equivalent to 0.15 lb/MMBtu based on a 30-day rolling average.

The Department also notes that the New Source Performance Standards in Subpart Da of 40 CFR 60 for electric utility steam generating units establishes a 30-day rolling NOx standard of 0.15 lb/MMBtu for units that are reconstructed or modified after July 9, 1997. In developing this standard, EPA recognized the retrofit capabilities of existing control equipment to comply with such a standard regardless of fuel type. Although the proposed boiler is not subject to the NSPS Subpart Da standard, the critical distinction is that steam generated from Boiler 8 will be used to support milling operations instead of electricity production. The proposed unit will be the largest sugarcane boiler constructed in the United States.

Two preliminary SNCR designs were included as part of the application, both based on urea injection. In general the designs support the following specifications: a maximum NOx reduction level of 50%; an ammonia slip level not to exceed 20 ppmvd @ 7% oxygen; at least three levels of ammonia injectors; control system to automatically adjust the urea injection zones and rates based on the furnace temperature profile, fuels, current urea injection rate, steam load, oxygen and CO levels, and NOx emissions. Both vendors supported a long-term average of 30 days. However, one vendor indicated that a NOx standard of 0.12 lb/MMBtu was achievable on a 24-hour basis.

In general, the urea-based selective non-catalytic reduction (SNCR) system will be designed and installed to reduce nitrogen oxide emissions in the flue gas exhaust by about 50% to achieve the specified emissions standard for nitrogen oxides. The preliminary design consists of the following equipment:

- Urea tank, static mixers, pumps, filters, and controller to blend urea and water for proper concentration;
- Three injection zones (lowest zone is for 50% boiler load and bagasse, middle zone is for maximum boiler load and bagasse, and highest zone is for auxiliary fuel firing);
- Dual-fluid nozzle atomizing injectors to mix urea and atomizing air for injection; and
- A PLC controller that automatically controls the urea injection rate and injector combinations based on the furnace temperature profile (input from infrared monitor), fuels, current urea injection rate, steam load, oxygen levels, carbon monoxide concentration, and NOx emissions.

Urea injection will occur in the boiler exhaust at a point where the flue gas is between approximately 1800° F and 1950° F. A maximum of 45 gph of diluted urea will be injected under maximum load conditions with a minimum design residence time for reaction of 0.5 seconds. The design ammonia slip is less than 20 ppmvd.

The Department agrees that an SNCR system is appropriate for the control of NOx emissions from the proposed bagasse-fired boiler. Based on the available information, the Department makes the following preliminary NOx BACT determination.

NOx ≤ 0.14 lb/MMBtu based on a 3-run test average conducted at permitted capacity and steady-state conditions

≤ 81 ppmvd @ 7% oxygen based on a 30-day rolling CEMS average excluding startup, shutdown, and malfunction

In addition to the SNCR system, the above standards are based on the proposed boiler design which will incorporate overfire air, low excess air, low nitrogen fuels, low-NOx burners for distillate oil firing, and good combustion practices. The standards apply when firing bagasse, distillate oil, or a combination of these fuels. An initial 3-run test (EPA Method 7E) will be required to demonstrate compliance when operating at permitted capacity, which is expected to result in the highest uncontrolled NOx emissions. Continuous compliance must be demonstrated based on NOx data collected from a Continuous Emissions Monitoring System (CEMS) over 30 successive boiler operating days. The Department believes that 30 operating days will provide more than adequate data to compensate for any fluctuations in emissions due to the varying bagasse characteristics. It is also notes that SNCR vendors typically design systems to achieve emissions standards on a daily basis or even less. To ensure that operation of the SNCR system does not result in excess ammonia emissions, the Department will limit the ammonia slip to 20 ppmvd @ 7% oxygen with compliance demonstrated by initial and annual tests in accordance with EPA Method CTM-027.

The Department will also establish the following additional standard for data that can be excluded from the compliance determination with the above standard due to startups, shutdowns, or malfunctions.

"For the period of excluded data, NOx emissions shall not exceed 162 ppmvd @ 7% oxygen based on a block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction (alternative standard)."

The alternate standard represents the highest expected NOx emissions and covers the periods during which the SNCR system may not be fully operational.

Particulate Matter (PM/PM_{10})

Total particulate matter (PM) and particulate matter less than 10 microns in diameter (PM_{10}) will be emitted from the proposed boiler due to the ash contents and incomplete combustion of bagasse and distillate oil. The ash content of bagasse ranges from about 2.6% to about 5.3% by weight on a dry basis. The ash content of distillate oil is about 0.06%. Proven control technologies are available for removing particulate matter from the flue gas exhaust of boilers.

Applicant's PM/PM_{10} Review

The applicant identified fuel substitutions, pretreatment devices, electrostatic precipitators (ESPs), fabric filters, and wet scrubbers as available add on equipment for the control of particulate matter. Fabric filters and ESPs were described as having control technologies exceeding 99%. The next highest ranked technology was wet scrubbing with estimated control efficiencies approaching 95%. The applicant identified fabric filters as not feasible for the proposed boiler due to the potential for:

- Plugging, blinding, and frequent bag replacement due to high flue gas moisture and "sticky" particles;
- Bag damage and frequent replacement resulting from high flue gas temperatures; and
- Potential for fire and explosion hazards.

A review of EPA's RACT/BACT/LAER Clearinghouse database shows about 20 similar industrial and electric utility biomass boiler projects. These projects established PM BACT standards based on ESPs, wet scrubbers, multi-cyclones, and fabric filters. The PM emission standards ranged from 0.02 to 0.30 lb/MMBtu. The large range of emission standards are the result of differences in boiler design, fuel types, and operation. Based on a review of previous determinations and available control technologies, the applicant proposed to install a wet cyclone pre-treatment device followed by a dry, negative corona plate ESP. The applicant recommends the following PM emission standard as BACT.

PM $\leq$ 0.026 lb/MMBtu of heat input based on 3-run test average

Opacity $\leq$ 20% based on a 6-minute average except for up to 27% for one 6-minute period per hour

The recommended PM standard represents an overall control efficiency of approximately 99% and is equivalent to the industrial boiler MACT recently proposed by EPA. The opacity limit is equivalent to NSPS Subpart Db standard. The applicant requested an alternate sampling procedure in lieu of the federal NSPS Subpart Db requirement to install a continuous opacity monitoring system (COMS). The request includes additional visible emissions observations when firing distillate oil as well as monitoring the total secondary power input to the ESP as a measure of effective performance. EPA Region 4 previously approved a similar plan for U.S. Sugar's Boiler 7. The Department expects EPA Region 4 to approve the requested Alternate Sampling Procedure for purposes of compliance with the NSPS Subpart Db provisions.

Department's Preliminary PM/PM_{10} BACT Determination

The Department also recognizes ESPs and fabric filters as the top-ranked control options for the removal of particulate matter. The applicant estimated the cost effectiveness of the wet cyclone collector/ESP combination at $118 per ton or particulate matter removed, which is well within the Department's cost considerations. The Department disagrees that fabric filters are not feasible for bagasse-fired boilers; however, it acknowledges the potential for fire problems due to the fly ash characteristics and plugging or blinding due to the high moisture levels of the flue gas. The proposed wet cyclone collector/ESP combination has been proven capable of achieving emission levels comparable to a fabric filter. Based on stack tests conducted on U.S. Sugar's Boiler 7 over the last several years, the average particulate matter emission rate is 0.013 lb/MMBtu (~ 0.007 grains/dscf). This is half of the proposed standard and within the range expected for control by a fabric filter.

A pre-control device will be designed and installed to remove entrained sand and large particles upstream of the electrostatic precipitator. The purpose of the pre-control device is to prevent excessive equipment wear and overloading of the ESP. The preliminary design locates two wet cyclone collectors in parallel before the induced draft fan. Each wet cyclone collector is expected to consist of a large steel vessel with a venturi throat located at the bottom for the inlet flue gas. A series of spray nozzles will be located in the venturi throat to supply a total of about 200-250 gpm of water for each unit. Water is used to wash the large particles away from the sides of the collector down to the discharge hopper. At an approximate flue gas flow rate of 191,000 acfm, the pressure drop across each collector is expected to be approximately 4 inches of water (gage). Flue gas will exit the top of the unit, which will also incorporate an emergency outlet should the normal outlet become plugged. The wet cyclone collectors are expected to remove approximately 50% of the inlet particulate matter, which is dependent on particle size.

The following specifications summarize the preliminary design of the proposed new ESP.

- *Performance*: The proposed ESP will be designed for a collection efficiency of more than 97.00%, a maximum controlled particulate emission rate of 0.026 lb/MMBtu, and a maximum stack opacity of 10%. EPA's AP-42 document estimates uncontrolled particulate matter emissions from firing bagasse of 15.6 lb/ton (~ 2.7 lb/MMBtu). A control efficiency of 99% or more is necessary to achieve the design outlet loading of 0.026 lb/MMBtu. Assuming 50% control by the wet cyclone (1.35 lb/MMBtu), a control efficiency of 98% or more is required to achieve the design outlet loading of 0.026 lb/MMBtu.
- *Specific Collection Area (SCA)*: The specific collection area is the ratio of the total collection surface area to the flue gas exhaust rate and is a rough indicator of the overall efficiency. The preliminary design has a total collection plate area in the range of 91,665 to 144,550 ft^2 based on a volumetric flow rate of about 400,000 ft^3/minute. This will place the SCA in the range of about 215 to 340 ft^2 per 1000 ft^3/minute, which falls within the optimum SCA range for fly ash precipitators (200 to 400 ft^2 per 1000 ft^3/minute). [3]
- *Aspect Ratio (L/H)*: The aspect ratio is ratio of the effective length of the ESP over the effective height of the ESP. If the aspect ration is small (< 1.0), then there is a greater chance that particulate matter will be re-entrained during periods of rapping and carried out of the ESP before reaching the hoppers. For the proposed ESP design, the effective field length is estimated between 36.4 and 40.8 feet and the effective field height is estimated at 36 feet. Therefore, the aspect ration will be in the range of 1.01 to 1.36, which falls with the expected range of aspect ratios (1.0 to 1.5) for ash precipitators with high collection efficiencies. [3]
- *Particle Migration Velocity (w)*: Particle migration velocity represents the *collectability* of a particle based on the design of a specific ESP. The critical design parameter for an ESP is the collection efficiency, which is a function of the plate collection area, the volumetric flow rate, and the particle migration velocity. The following simplified equation shows the general relationship of these parameters. [3]

  $Ac = - Q / w [\ln (1 - n)]$, where:

  Ac is the plate collection area, ft^2 (assume 91,665 to 144,550 ft^2)
  Q is the volumetric flow rate, ft^3/min (assume 400,000 acfm)
  w is the particle migration velocity, ft/sec
  n is the collection efficiency, decimal form, (assume 0.97)

  Rearranging the equation would be:

  $w = -$ (Q ft^3/min) / (118,108 ft^2) [ln (1 – 0.97)] (min/60 sec) = 0.20 ft/sec

  Based on the above equation and the preliminary design, a rough estimate of the particle migration velocity is between 0.16 to 0.26 ft/second, which falls within the expected range of particle migration velocities (0.1 to 0.5 ft/sec) for fly ash precipitators.[1, 3]

- *Plate Area / Electrical Transformer-Rectifier (T-R) Set*: In most cases, more electrical bus sections (T-R sets) means a higher probability of continually achieving the designed collection efficiency. A general rule-of-thumb for fly ash precipitators is to have one T-R set for every 10,000 to 30,000 ft^2 of collection plate area.[1, 3] Based on preliminary information, the design should have between 4 and 9 TR-sets for a design collection area of 91,665 ft^2 and between 5 and 14 T-R sets for a design collection area of 144,550 ft^2. Total power consumption is expected to range from 231-303 kW.

After review of the available information, the Department establishes the following preliminary BACT standard for particulate matter based on the proposed wet cyclone/ESP design.

PM $\leq$ 0.026 lb/MMBtu of heat input based on a 3-run test average (EPA Method 5) at permitted capacity

Opacity $\leq$ 20% based on a 6-minute average (EPA Method 9)

The above PM standard is equivalent to the industrial boiler MACT standard that was recently proposed by EPA as achievable for solid fuel fired boilers. It is equivalent to approximately 0.014 grains per dry standard cubic feet of flue gas, which approaches the level of control offered by a baghouse. There appears to be little benefit in establishing a very low opacity limit for the new unit, which will be located adjacent to existing boilers with wet scrubbers, condensing water vapor plumes, and opacity limits as high as 30% to 40%. The above opacity standard does not allow the exceptional period granted by NSPS Subpart Db. A properly functioning ESP will be able to comply with 20% opacity at all times. During startup and shutdown, the Department will establish the following opacity standard.

Opacity $\leq$ 20% based on a 6-minute average except for up to 27% for one 6-minute period per hour (EPA Method 9)

In general, this standard will apply for two cases: during an initial startup when the boiler is firing only distillate oil; and during shutdown when bagasse is no longer being fired and the ESP is taken off line because combustion on the grate is substantially complete. Because EPA Region 4 has not yet approved the Alternate Sampling Procedure for opacity, draft permit will include the NSPS Subpart Db requirement for a COMS. However, the permit allows the uses of the Alternate Sampling Procedure in lieu of a COMS if later approved by EPA Region 4. The permit also includes a plan to test and establish a minimum total secondary power input level for the ESP, which represents effective performance.

Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)

These pollutants will be emitted due to the available sulfur in the bagasse and distillate oil being fired. Bagasse typically contains 0.03% to 0.07% by weight on a dry basis and the proposed distillate oil will contain no more than 0.05% sulfur by weight. For fuel oil firing, nearly all of the fuel sulfur is converted to SO_2 and possibly some SAM. However, the sugar industry has test data for bagasse combustion showing actual SO_2 emissions that are much lower than the amount predicted by simple stoichiometry. It is believed much of the SO_2 formed is adsorbed onto the alkaline fly ash particles that are generated during bagasse combustion.

<u>Applicant's SAM and SO_2 Review</u>

The applicant identified sorbent injection (~ 50-80% reduction), wet scrubbing (> 90% reduction), dry scrubbing (> 90% reduction), spray dryer scrubbing (~ 90-95% reduction), and regenerative flue gas desulfurization systems with recovery of sulfur or sulfuric acid (> 95% removal) as feasible controls for the removal of SO_2 emissions. The applicant states that the levels of control are similar and that spray dryer scrubbers are generally less expensive than the other methods. Two cost quotes were obtained for a lime spray dryer absorber with pulse jet baghouse and ancillary equipment. Estimated total capital costs ranged from about $12 to $15 million. Annual operating and maintenance costs ranged from about $780,000 to $900,000. Based on a 90% reduction, the cost effectiveness ranged from $5500 to $7700 per ton of SO_2, HF, and HCl emissions removed. The applicant believes that these costs are unreasonable for this project. Costs for other add on controls are expected to be much higher and also not cost effective.

A review of EPA's RACT/BACT/LAER Clearinghouse database shows 15 similar industrial and electric utility biomass boiler projects. These projects established SO_2 BACT standards ranging from 0.016 to 0.54 lb/MMBtu. Two projects required wet scrubbers, one project required a spray dryer absorber, and the remaining projects relied on low sulfur fuels. The following table lists the standards for the projects with controls.

Table 4B. Recent BACT Determinations for Biomass Boilers Requiring Add-On Controls

RBLC ID	State	Project	Permit Date	Capacity MMBtu/hr	Standard lb/MMBtu	Control / Fuel
ME-0021	ME	S.D. Warren Co., Boiler 2	11/27/01	1300	0.27	Wet Scrubber / Wood
AL-0112	AL	Champion International	12/09/97	710	0.045	Wet Scrubber / Wood
FL-0198	FL	Wheelabrator Ridge Energy	0929/92	630	0.1	SDA / Wood/RDF

The S.D. Warren project is a paper mill power boiler that fires bark, wood, sludge, No. 6 fuel oil, tire-derived fuel, and waste oil. Similarly, the Champion International project is paper mill power boiler that fires wood, paper, effluent treatment solids, tire-derived fuel, natural gas, and non-condensable gases. The Wheelabrator Ridge Energy project is a waste-to-energy boiler that fires wood, tire-derived fuels, and refuse. Due to the high-sulfur fuels being fired at each plant, the uncontrolled SO_2 emissions would be much higher than emissions from the proposed project, which would make add-on controls appear more cost effective. However, the standards for the S.D. Warren and the Wheelabrator Ridge Energy projects are still higher than predicted emissions from the proposed project. The standard for the Champion International project is about 25% lower than the maximum predicted for the proposed project. Based on the use of low sulfur fuels, the applicant recommends the following SO_2 standards as BACT.

SO_2 $\leq$ 0.06 lb/MMBtu of heat input for bagasse firing, 3-run test average

Fuel sulfur $\leq$ 0.05% sulfur by weight for distillate oil

Due to the predicted low levels of sulfuric acid mist emissions, the SO_2 standards and distillate oil sulfur specification will serve as surrogate standards that effectively limit potential emissions of this pollutant.

Department's Preliminary SO_2 BACT Determination

The Department believes that the applicant's estimated cost effectiveness of $5500 to $7700 per ton of acid gases removed may be at the high end of consideration. However, based on CEMS data collected in 2000 for the similar New Hope Power cogeneration boilers, the annual SO_2 emission rate is approximately 0.03 lb/MMBtu when firing a combination of wood and bagasse. Wood typically has a higher sulfur content than bagasse and generally results in higher SO_2 emissions. Therefore, this long-term average should be a conservative factor for estimating annual SO_2 emissions from Boiler 8. Basing the annual emission reductions on this factor increases the cost effectiveness of a spray dryer absorber to more than $10,000 per ton. This is clearly not cost effective. In addition, the purchased equipment cost is about $6.5 million for the spray dryer absorber, which is nearly 45% of the estimated purchased equipment cost of the new boiler (~ $15 million). Therefore, the Department rejects add on flue gas desulfurization as not cost effective for this project.

Based on a review of the available information, the Department makes a preliminary determination that the following SO_2 emission standards represent BACT based on low sulfur fuels.

SO_2 $\leq$ 0.06 lb/MMBtu of heat input for bagasse firing based on a 3-run stack test at permitted capacity

Fuel sulfur $\leq$ 0.05% sulfur by weight for distillate oil

The above distillate oil sulfur specification has been frequently established as the BACT standard for modern gas turbine projects. This is equivalent to 0.051 lb/MMBtu, which is nearly comparable to the standard for bagasse. Although the actual SO_2 emissions when firing bagasse are expected to be less than 0.03 lb/MMBtu, bagasse may vary significantly from sample to sample. Therefore, the applicant's requested standard of 0.06 lb/MMBtu is considered reasonable as compliance will be based on an annual 3-run stack test (EPA Method 6C). The draft permit will also include requirements to periodically sample and analyze the bagasse for the fuel sulfur content. Due to the predicted low levels of sulfuric acid mist emissions, the SO_2 standard and distillate oil sulfur specification will serve as surrogate standards that effectively limit potential emissions of this pollutant.

Lead, Mercury, and Fluorides

The potential net emission increases of lead, mercury, and fluorides are predicted to be less than half of the corresponding PSD significant emission rates. These estimates are based on emission factors that are believed to be very conservative for bagasse-fired boilers. In addition, the wet cyclone collector/ESP combination is expected to be very effective in the removal of particulate forms of these contaminants. Therefore, similar to the proposed MACT standard, no specific standards are established. However, the low particulate matter emission standard serves as a surrogate for the overall control of these pollutants.

5. BAGASSE HANDLING SYSTEM, CONTROL TECHNOLOGY REVIEW

Due to this project, emissions increases of CO, NOx, PM, SAM, SO_2, and VOC will result from small miscellaneous sources in the refinery and from bagasse handling system. However, the emissions increases for CO, NOx, SAM, SO_2, and VOC are generally less than 1% of the overall potential emissions from the project sources and not considered substantial. Therefore, the Department determines that these activities will continue to be regulated by current permits. However, PM emission increases from the bagasse handling system (~ 18.5 tons per year) represent approximately 15% of the overall potential emissions from the project sources. Therefore, the Department will establish BACT standards for these activities.

U.S. Sugar proposes the following changes to the existing bagasse conveyor system accommodate Boiler 8: expand conveyor belt C4; add a new conveyor belt to feed bagasse to Boiler 8; and increase the bagasse throughput of the handling system. The proposed changes also involve installing only 5 of the 6 previously proposed dust collectors for the bagasse handling system and eliminate transfer belt conveyor No. 2 (Application Nos. 0510003-011-AC and 0510003-015-AC). The combined flow rates of the dust collectors will be 18,475 acfm. The collection efficiency of the dust collectors is estimated to be 99.99% for particles greater than 4 microns in diameter. The following table summarizes the revised dust collector system:

Table 5A. Bagasse Conveyor Dust Collection System

Dust Collector	Manufacturer	Model No.	Flow Rate acfm	Outlet grains/afc	~ Outlet Height, feet
1	Prime Systems	BV-6X8-120	3550	0.02	57
2	Prime Systems	BV-8X8-120	3100	0.02	62
3	Prime Systems	BV-8X7-120	4725	0.02	61
4	Prime Systems	BV-6X8-120	3550	0.02	57
5	Prime Systems	BV-6X8-120	3550	0.02	57

The applicant recommends enclosing bagasse conveyors, installing dust collectors on the conveyor transfer points, and a work practice standard of 5% opacity for each of the dust collector outlets. Based on a review of the available information, the Department makes a preliminary determination that the following work practice standards represent BACT for controlling particulate matter emissions from the bagasse handling system.

- Enclose bagasse conveyors;
- Install dust collectors on the conveyor transfer points;
- Opacity from the dust collector outlets shall not exceed 5% opacity

Initial and annual compliance with the opacity standard will be determined by EPA Method 9.

6. COMMENTS ON THE APPLICATION

Comments from the National Park Service

The National Park Service (NPS) indicated that it did not anticipate that the proposed project will have a significant impact on the Everglades National Park. However, NPS offered the following comments on the Best Available Control Technology (BACT) analysis presented in the application.

1. Particulate Matter: U.S. Sugar proposes an electrostatic precipitator (ESP) at an emission rate of 0.026 lb/MMBtu. We agree with the choice of an ESP and with the proposed emission rate.

   Department's Response: The draft permit reflects this level of control.

2. Nitrogen Oxides: U.S. Sugar concluded that over-fire air and "good combustion practices" represent BACT at an average emission rate of 0.22 lb/MMBtu. In its 1999 application to increase the permitted operating hours of its bagasse and #6 oil-fired Boiler #4, U.S. Sugar concluded that "good combustion practices" represent BACT because they were achieving an average emission rate of 0.08 lb/MMBtu. We believe that a new boiler should be able to control NO_x emissions to levels no greater than demonstrated by Boiler #4 burning the same fuel (i.e., 0.08 lb/MMBtu).

   U.S. Sugar rejected Selective Non-catalytic Reduction (SNCR) based upon a cost-effectiveness of $1400 per ton of NO_x removed. We suggest that $1400/ton may be economically feasible on the basis that many states use a cost-effectiveness threshold of $2000-$5000/ton for NO_x.

   Department's Response: The proposed unit will be a newly designed, modern spreader stoker boiler. As such, the operating temperatures, combustions efficiency, and NOx emissions are expected to be much higher than Boiler 4, which is a refurbished power plant boiler originally constructed prior to 1970. The less efficient combustion design of Boiler 4 leads to much higher emissions of carbon monoxide and organic compounds. The proposed design is expected to result in uncontrolled NOx emissions as high as 0.28 lb/MMBtu. For this reason, the Department's preliminary BACT determination is a NO emission rate of 0.14 lb/MMBtu based on the installation of SNCR.

3. Sulfur Dioxide: U.S. Sugar proposed firing of 0.05% sulfur fuel oil as BACT. By 2006, the Environmental Protection Agency (EPA) will require that 80% of all on-road diesel fuel meet a sulfur limit of 0.01%, and by 2010, 100% of all on-road diesel fuel must meet that limit. Although those EPA limits will not directly apply to fuel oil burned in a boiler such as that proposed by U.S. Sugar, it is clear that 0.01% sulfur oil will be readily available by 2006. We are aware of at least four proposed combustion turbine projects in Virginia (Tenaska-Bear Garden, Tenaska-Fluvanna Co., Dynegy-Chickahominy Power, and ODEC-Louisa Co.) and one facility in Georgia (Southern Co.-Macintosh) that have proposed the use of fuel oil limited to 0.01% sulfur. U.S. Sugar should address the feasibility of using such a lower sulfur fuel oil in its BACT analysis. We request U.S. Sugar be required to purchase and use 0.01% sulfur oil no later than 2006.

   Department's Response: In making the BACT determination, the Department relied on information available at the time of the application review. Although there are proposals to lower the fuel sulfur as described, it does not seem appropriate to base the BACT determination for a supplemental fuel on *proposed* fuel sulfur levels and implementation dates. At full permitted capacity, the difference in the fuel sulfur limits would result in a maximum potential decrease of less than 20 tons per year. The Department's BACT determination includes a fuel sulfur specification of 0.05% sulfur by weight or less.

7. AIR QUALITY ANALYSIS REVIEW

Introduction

The proposed Boiler 8 project will result in net annual emissions increases that exceed the PSD significant emission rates for nitrogen oxides (NOx), particulate matter (PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). NOx, PM_{10}, and SO_2 are all criteria pollutants with defined significant impact levels, PSD increments, state and federal ambient air quality standards (AAQS), and de minimis preconstruction monitoring concentrations. SAM is a non-criteria pollutant with no defined significant impact levels, PSD increments, AAQS, or de minimis preconstruction monitoring concentrations. Therefore, no air quality impact analysis is required for SAM. VOC is a precursor for ozone, which is a criteria pollutant. For VOC, there are no applicable significant impact levels, PSD increments, or AAQS. However, projects with net increases of more than 100 tons per year of VOC require an ambient impact analysis. Due to the shutdown of Boiler 3, net emissions increases of carbon monoxide (CO) are below the PSD significant emission rate and the project nets out of PSD preconstruction review for this pollutant. In summary, the air quality impact analyses required by the PSD regulations for this project include:

- An analysis of existing air quality for PM_{10}, SO_2, and VOC;
- A significant impact analysis for NO_2, PM_{10}, SO_2, and VOC;
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The analyses for significant impacts, PSD increments, and AAQS depend on air quality dispersion modeling carried out in accordance with EPA and Department guidelines. The analysis of growth-related impacts to air quality generally focuses on a qualitative review of residential, commercial, and industrial growth in the vicinity of the project.

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A discussion of the required analyses follows.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied by existing representative monitoring data, if available. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration.

If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. The background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year.

The following table shows maximum predicted air quality impacts from the project compared to the de minimis preconstruction ambient air quality monitoring levels.

Table 7A. Predicted Maximum Air Quality Impacts from the Project Compared to the De Minimis Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater than De Minimis?	De Minimis Level ($\mu g/m^3$)
SO_2	24-hr	2.3	No	13
PM_{10}	24-hr	4.9	No	10
NO_2	Annual	0.5	No	14
VOC	Annual	168 (133) tons/year*	Yes	100 tons/year

* The net annual VOC emissions increases for the project are: 168 tons/year based on the application and 133 tons/year based on the preliminary BACT determination.

With the exception of VOC, all pollutants are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required. Because VOC impacts from the project are predicted to be greater than the de minimis level, the applicant is not exempt by rule from preconstruction monitoring for this pollutant. However, the applicant may satisfy the preconstruction monitoring requirement by using previously existing representative data. There are no ambient monitors located in Hendry County, which remains a relatively rural area as discussed in the Additional Impacts Analysis. However, conservatively representative data is available for the more urbanized adjacent Palm Beach County located east of the project. Existing monitoring data shows the area to be in attainment with the ozone standard. No background concentrations were established because there were no predicted significant impacts for any pollutants, which will be shown in the following section.

Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

PSD Class II Area Model

Typically, the EPA-approved Industrial Source Complex Short Term (ISCST3) model is used in the significant impact modeling analysis. However, for a previous project (Permit No. PSD-FL-272), EPA Region 4 approved the use of a modified version of the program that included Plume RIse Model Enhancements (ISC-PRIME). The applicant successfully argued that the ISC-PRIME model was better suited for handling the complex building downwash scenarios at the Clewiston sugar mill and refinery. Once the ISC-PRIME model is approved for a given facility, it is EPA's policy that the alternate model be used on all subsequent projects for purposes of consistency. Therefore, the applicant performed the required air dispersion modeling to demonstrate compliance with the ambient air quality standards and PSD increments using the previously approved ISC-PRIME model.

The ISC-PRIME model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISC-PRIME model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISC-PRIME model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Because five years of data are used in ISC-PRIME, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if there are significant impacts occur from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

PSD Class I Area Model

Since the PSD Class I CNWA is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments, regional haze and maximum sulfur and nitrogen deposition in the Everglades National Park. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. For this project, the CALPUFF analysis used MM4/MM5 data from 1990, 1992 and 1996 to initialize the CALMET wind field. The CALMET model produced a modeling domain extending 470 km in the north-south direction by 450 km in the east-west direction. The modeling domain was produced by using meteorological data from 3 upper air, 8 surface, and 23 precipitation stations located throughout the state of Florida.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 500 receptors were placed along the facility's restricted property line and out to 25 km from the facility, which is located in a PSD Class II area. Modeling refinements were done, as needed, by using a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of one or two degrees. 126 receptors were placed in the Everglades National Park (ENP) PSD Class I area located 102 km away at its closest point. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in the vicinity of the facility or in the Class I areas. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of the modeling for significant impacts, including the radius of significant impact, if applicable.

Table 7B. Maximum Predicted Project Impacts in the Vicinity of the Facility Compared to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact? (Yes/No)	Radius of Significant Impact (km)
SO_2	Annual	0.1	1	No	--
	24-hr	2.3	5	No	--
	3-hr	14.6	25	No	--
PM_{10}	Annual	0.97	1	No	--
	24-hr	4.9	5	No	--
NO_2	Annual	0.5	1	No	--

Table 7C. Maximum Predicted Project Impacts in the Everglades National Park (ENP) Compared To the PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact? (Yes/No)
SO_2	Annual	0.003	0.1	No
	24-hr	0.11	0.2	No
	3-hr	0.75	1.0	No
PM_{10}	Annual	0.001	0.2	No
	24-hr	0.01	0.3	No
NO_2	Annual	0.004	0.1	No

As shown in the above tables, the maximum predicted air quality impacts due to all pollutants are less than the PSD significant impact levels in the vicinity of the facility and in the Everglades National Park (ENP); therefore, no further modeling was required.

Discussion of VOC Emission Impacts

Ozone is a criteria pollutant and the prime ingredient in urban "smog". It is not directly emitted from stationary sources, but is formed at ground level through a series of complex chemical reactions involving emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC) in the presence of sunlight. For this reason, VOC emissions are regulated as a precursor for the criteria pollutant ozone. As previously mentioned, potential VOC emissions increases are above the de minimis level of 100 tons per year, which requires an ambient impact analysis and a gathering of ambient ozone concentrations.

Impacts of VOC emissions on ambient ozone levels are not usually realized locally, but contribute to the regional formation of ozone. However, the main impact on ozone from stationary sources in the area is likely due to NOx rather than VOC emissions. Furthermore, ozone formation occurs on a regional basis and includes the contributions of emissions from such as motor vehicle traffic, large power plants, and numerous miscellaneous VOC sources throughout the region. In general, it is found that motor vehicles contribute the majority of VOC emissions in urban areas having adverse ambient ozone levels.

Based on information in Florida's Air Resource Management System database, existing stationary sources in Hendry County accounted for 3148 tons per year of VOC emissions in 2002. The maximum net VOC emissions increase from the project would be 133 tons per year, which represents only a 4% increase in stationary source VOC emissions. This is still a relatively small contribution towards regional ozone formation. It is further noted that actual VOC emissions from the proposed Boiler 8 are expected to be about half of the maximum permitted levels, which would bring the net VOC emissions increases below the 100 ton per year de minimis level.

As shown in the Additional Impacts Analysis, Hendry County is a lightly populated rural area. As such, ambient ozone levels are predicted to be low and no monitoring network has been established. However, representative data is available for the more urbanized Palm Beach County located east of the project, which offers a conservative estimate for Hendry County. Data from this regional ozone monitoring system would satisfy any pre-construction monitoring requirements as well as provide a conservative estimate of background ozone levels. The existing regional ozone monitoring data shows the area to be in attainment with the ozone standards.

The applicant presented the potential VOC emissions increases to the Department and discussed available options to predict potential impacts associated with the emissions and formation of ozone. However, there are no approved stationary point source models available for use in predicting ozone impacts. Actual annual VOC emissions from the proposed Boiler 8 are expected to be less than 100 tons per year based on predicted operational levels. Ambient ozone monitoring data collected by the regional monitoring system over the last several years show attainment with the current ozone standards and predicts attainment with the proposed new ozone standards. Based on the available information, the Department determines that the use of a complex regional model incorporating the intricate chemical mechanisms for predicting ozone formation is not suitable for this project, nor would it be sensitive enough to evaluate impacts associated with the changes in ambient ozone levels due to this project. Therefore, no further analysis is required.

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM_{10}, SO_2, NOx and CO emissions as a result of the proposed project, including all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected. A regional haze analysis using the long range transport model CALPUFF was done for the ENP Class I area. This analysis showed no significant impact on visibility in this area. The maximum predicted sulfur and nitrogen deposition on the Everglades National Park from this project was below the Federal Land Manager criteria.

Growth-Related Air Quality Impacts

Hendry County is located south of Lake Okeechobee and west of Palm Beach County. Consisting of approximately 1163 square miles, it is the 8th largest county based on land area. However, Hendry County accounts for only 37,000 of the 16 million Florida residents. In contrast, the adjacent and more urbanized Palm Beach County has approximately 1.2 million residents. Hence, Hendry County may be described as a lightly populated rural area. [Population information is based on 2001 data from the U.S. Census Bureau.]

The applicant provided the following information on trends (1977 to 2000) for Hendry County based on data from the "Florida Statistical Abstract".

- *Population*: The population increased by about 19,300 (~ 114% increase).
- *Retail Trade*: Approximately 29 retail trade establishments were added (~ 28% increase).
- *Labor*: About 6265 people were added to the available work force (~ 87% increase).
- *Tourism*: Hotels and motels increased available capacity by about 49%.
- *Transportation*: The estimated vehicle miles traveled (VMT) on major roadways increased by 280,000 VMT (~ 86% increase).
- *Power Plants*: There are no power plants in Hendry County.
- *Manufacturing*: Industry showed a 25% increase in the number of employees.

- *Agriculture*: Agricultural industries showed a 91% increase in the number of employees. The largest nearby newly constructed stationary source is the Southern Gardens Citrus Processing Corporation.

This information suggests that Hendry County has experienced only modest growth since 1977. During the expected two years of construction, the project is expected to require about 25 additional workers. After completion of the project, no additional operational workers will be required. Based on this information, there will be negligible air quality impacts from any growth associated with the project.

8. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing the air quality modeling analysis. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

{Filename: PSD-FL-333 Boiler 8 - TEPD}

DRAFT PERMIT

PERMITTEE:

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Authorized Representative:
Mr. William A. Raiola, V.P. of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
Facility ID No. 0510003
SIC Nos. 2061, 2062
Permit Expires: December 31, 2006

FACILITY AND LOCATION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery.

STATEMENT OF BASIS

This permit authorizes the construction of Boiler 8 (EU-028), a new bagasse-fired boiler with a maximum heat input rate of 1030 MMBtu/hour. The permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to perform the proposed work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

(DRAFT)

Michael G. Cooke, Director
Division of Air Resources Management

Effective Date

PROJECT DESCRIPTION

The United States Sugar Corporation proposes to construct Boiler 8 (EU-028), which will fire bagasse as the primary fuel. Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Air pollution control equipment includes a wet cyclone/electrostatic precipitator (ESP) combination to remove particulate matter and a selective non-catalytic reduction system (SNCR) to reduce nitrogen oxides. Good combustion design and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Bagasse and distillate oil ($\leq 0.05\%$ sulfur by weight) will be used to minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Monitoring equipment will continuously monitor and record emissions of carbon monoxide and nitrogen oxides. To minimize fugitive particulate matter from the bagasse handling system (EU-027), bagasse conveyors will be enclosed and dust collectors installed on the conveyor transfer points. The project will also potentially cause small increases in actual annual emissions from miscellaneous existing activities in the refinery.

REGULATORY CLASSIFICATION

Title III: The existing facility is a potential major source of hazardous air pollutants (HAP).

Title IV: The existing facility has no units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The existing facility operates units subject to the New Source Performance Standards of 40 CFR 60.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Formats
Appendix B. General Conditions
Appendix C. Common Requirements
Appendix D. NSPS Requirements
Appendix E. Final BACT Determinations
Appendix F. Good Combustion and Operating Practices
Appendix G. Quarterly CO and NOx Emissions Report

RELEVANT DOCUMENTS

The permit application and additional information received to make it complete are not a part of this permit; however, the information is specifically related to this permitting action and is on file with the Department.

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to construct minor sources of air pollution or to operate the facility shall be submitted to the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's South District Office at the above address.

3. Rule Citations: Appendix A of this permit explains the methods used to cite rules, regulations, and permits.

4. General Conditions: The permittee shall comply with the general conditions specified in Appendix B of this permit. [Rule 62-4.160, F.A.C.]

5. Common Requirements: The permittee shall comply with the common regulatory requirements specified in Appendix C of this permit. [Chapters 62-4, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.]

6. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and Title 40 of the Code of Federal Regulations (CFR) adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]

8. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

9. Relaxations of Restrictions on Pollutant Emitting Capacity. If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7,1980, then at the

time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rule 62-4.030 and Chapters 62-210 and 62-212, F.A.C.]

11. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's South District Office with a copy to the Department's New Source Review Section in the Bureau of Air Regulation. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

A. Boiler 8

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
028	*Description*: Boiler 8 will be a membrane wall boiler with balanced draft stoker, overfire air, rotating feeders, and pneumatic spreaders. It will be designed to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. *Fuels*: The primary fuel will be bagasse (SCC No. 1-02-011-01). Distillate oil (SCC No. 1-02-005-01) containing less than 0.05% sulfur by weight will be fired as a restricted alternate fuel for startup and supplemental uses. *Capacity*: The maximum continuous steam production 500,000 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour averages). *Controls*: Particulate matter is controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. *Stack Parameters*: The stack will be 13.0 feet in diameter (maximum) and 199 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of 330° F and a volumetric flow rate of 400,000 acfm at 5.5% oxygen (225,000 dscfm at 7% oxygen). *CEMS*: Emissions of carbon monoxide and nitrogen oxides will be monitored and recorded by continuous emissions monitoring systems (CEMS).

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The final BACT determinations are presented in Appendix E of this permit. Boiler 8 is also subject to the following applicable requirements: Rule 62-296.405, F.A.C. (fossil fuel fired steam generators with more than 250 MMBtu per hour of heat input); Rule 62-296.410, F.A.C. (carbonaceous fuel burning equipment); and the federal New Source Performance Standards (NSPS) in Subpart Db (industrial boilers) of 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C. See Appendices C and D of this permit for these applicable requirements.}

EQUIPMENT

1. Shutdown of Boiler 3: Boiler 3 shall be permanently shutdown prior to operation of Boiler 8. In no case, shall Boilers 3 and 8 operate concurrently. No later than 30 days after first firing bagasse in Boiler 8, the permittee shall submit written notice to the Compliance Authority confirming first fire in Boiler 8 and the permanent shutdown of Boiler 3. *{Permitting Note: Emissions decreases from the shutdown of Boiler 3 were used in the netting analysis to avoid PSD review of CO emissions for this project.}* [Design; Rule 62-212.400(2)(e) and (g), F.A.C.]
2. Construction of Boiler 8: The permittee is authorized to construct a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 550,000 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. Rotating feeders,

pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse. Low NOx burners will be used to fire distillate oil as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. Within 90 days of selecting the final design and vendor, the permittee shall submit the final primary design details of the proposed boiler. [Design]

3. Air Pollution Control Equipment: To comply with the standards of this permit, the permittee shall install the following air pollution control equipment.

   a. *Wet Cyclone Collectors*: The permittee shall design, install, operate, and maintain a pre-control device prior to the electrostatic precipitator (ESP) to remove entrained sand and large particles in the flue gas. The purpose of the pre-control device is to prevent excessive equipment wear and overloading of the ESP. The preliminary design is to locate two wet cyclone collectors in parallel before the induced draft fan. Upon written approval of the Department, equivalent equipment may be installed.

   b. *ESP*: The permittee shall design, install, operate, and maintain an electrostatic precipitator (ESP) to remove particulate matter from the flue gas exhaust and achieve the particulate matter standards specified in this permit. The ESP shall include an automated rapping system that can adjust rapping frequency and intensity to prevent re-entrainment of fly ash. The ESP shall be on line and functioning properly whenever bagasse is fired.

   c. *SNCR*: The permittee shall design, install, operate, and maintain a urea-based selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide emissions in the flue gas exhaust and achieve the nitrogen oxides emissions standards specified in this permit. The system shall include automated control of urea injection for at least three injection zones to respond to varying load and flue gas conditions. The combinations of urea injection rates and zones will be determined based on the current injection rate, furnace temperature profile, fuels, steam load, oxygen level, carbon monoxide level, and nitrogen oxide emissions.

   Within 90 days of selecting the final equipment designs and vendors, the permittee shall submit the final primary design details for the proposed pollution controls. [Design; Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary fuel and distillate oil as a restricted alternate fuel for startup and supplemental uses. Bagasse is the fibrous material remaining after sugarcane is milled. Only new No. 2 (or superior) distillate oil containing no more than 0.05% sulfur by weight shall be fired. [Design; Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

5. Boiler Capacities and Restrictions: The maximum continuous steam production capacity (24-hour average) is 500,000 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour average). The total maximum heat input from the oil burners is 562 MMBtu per hour (4161 gallons/hour). Boiler 8 shall not exceed the following operational levels.

   a. 12,000,000 pounds of steam per day (equivalent to 500,000 pounds of steam per hour and 936 MMBtu per hour, 24-hour averages);

   b. $3.6135 \times 10^{+09}$ pounds of steam per consecutive 12 months (equivalent to 6,767,100 MMBtu per year);

   c. 99,864 gallons of distillate oil per day (equivalent to 13,488 MMBtu per day); and

   d. 6,073,600 gallons of distillate oil per consecutive 12 months (equivalent to 819,936 MMBtu per year).

   The hours of operation are not restricted (8760 hours/year). *{Permitting Note: The short-term restrictions* *form the basis of the Air Quality Analysis. The restriction on annual steam production is a surrogate for heat input and allowed the project to avoid PSD applicability for carbon monoxide emissions. The annual oil firing restriction results in an annual capacity factor of 10% or less, which avoids specific requirements in NSPS Subpart Db.* [Design; Applicant Request; Rules 62-4.070(3), 62-212.400(2)(g), 62-210.200(PTE), F.A.C.; NSPS Subpart Db]

6. Good Combustion and Operating Practices: The permittee shall follow the good combustion and operating practices identified in Appendix F of this permit. [Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: See Appendix E of this permit for a summary of the final BACT determinations.}

7. Standards Based on Stack Tests: The following emission standards apply when firing bagasse, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. Unless otherwise specified, compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

   a. Ammonia Slip: As determined by EPA Conditional Test Method CTM-027, ammonia slip shall not exceed 20 ppmvd @ 7% oxygen. [Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

   b. Carbon Monoxide (CO): As determined by EPA Method 10 stack test, CO emissions shall not exceed 0.38 lb/MMBtu and 355.7 pounds per hour. [Rules 62-4.070(3) and 62-212.400(2)(g), F.A.C.]

   c. Nitrogen Oxides (NOx): As determined by EPA Method 7E stack test, NOx emissions shall not exceed 0.14 lb/MMBtu and 131.0 pounds per hour. *{Permitting Note: This is equivalent to 81 ppmvd @ 7% oxygen.}* [Rule 62-212.400(5)(c), F.A.C.]

   d. Opacity: As determined by EPA Method 9 observations or COMS, the stack opacity shall not exceed 20% based on a 6-minute average. [Rule 62-212.400(5)(c), F.A.C.]

   e. Particulate Matter (PM/PM_{10}): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.026 lb/MMBtu and 24.3 pounds per hour. [Rule 62-212.400(5)(c), F.A.C.]

   f. Sulfur Dioxide (SO_2): As determined by EPA Method 6C stack test, SO_2 emissions shall not exceed 0.06 lb/MMBtu and 56.2 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400(5)(c), F.A.C.]

   g. Volatile Organic Compounds (VOC): As determined by EPA Methods 18 and 25A stack tests, VOC emissions shall not exceed 0.05 lb/MMBtu and 46.8 pounds per hour measured as propane. For this permit, "VOC" emissions shall be defined as the total hydrocarbons (THC) measured by EPA Method 25A less the sum of the methane and ethane emissions as measured by EPA Method 18 on a concurrent sample. Alternatively, the permittee may elect to assume that all THC are regulated VOC emissions. [Rule 62-212.400(5)(c), F.A.C.]

8. Standards Based on CEMS: The following emission standards apply when firing bagasse, distillate oil, or a combination of these fuels and under all load conditions.

   a. Carbon Monoxide (CO): As determined by CEMS data, CO emissions shall not exceed 1285 tons per consecutive 12 months. *{Permitting Note: Compliance with the annual CEMS standard ensures that the project is not subject to PSD preconstruction review for CO emissions.}* [Rules 62-4.070(3) and 62-212.400(2)(g), F.A.C.]

   b. Nitrogen Oxides (NOx): As determined by CEMS data, NOx emissions shall not exceed 81 ppmvd @ 7% oxygen based on a 30-day rolling average. [Rule 62-212.400(5)(c), F.A.C.]

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

9. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with the following. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. A full written report on the malfunctions shall be submitted in a quarterly report. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

10. Excess Emissions - Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

11. Excess Emissions - Allowed: Unless otherwise specified by this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

12. Excess Emissions – CO, NOx, and Opacity Requirements: As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.

   a. *CO Emissions*: All valid CO data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the 12-month rolling emissions standard based on CEMS data. Emissions in excess of the 12-month rolling emissions standard are not allowed.

   b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, and malfunction may be excluded from the determination of compliance with the 30-day rolling emissions standard, provided:

      1) Best operational practices are used to minimize emissions;

      2) For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional;

      3) For malfunctions, excluded data shall not exceed two hours in any 24-hour period and the permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

      4) For the period of excluded data, NOx emissions shall not exceed 162 ppmvd @ 7% oxygen based on a block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction (alternative standard).

   c. *Opacity*: During startup and shutdown, the stack opacity shall not exceed 20% opacity based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity. *{Permitting Note: This alternate opacity standard does not impose a separate annual testing requirement.}*

TESTING REQUIREMENTS

13. Boiler Performance Test: Within 180 days of first fire on bagasse, the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted when firing only bagasse and shall be at least three hours long. The bagasse fuel firing rate (tons per hour) shall be carefully monitored and

recorded. A sample of the as-fired bagasse shall be analyzed for the heating value (Btu/lb) and moisture content (%). The actual heat input rate (MMBtu/hour) shall be determined using two methods: the bagasse feed rate with fuel analysis and steam parameters with enthalpies. Results of the test shall be submitted to the Department within 45 days of completion. The tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. [Rule 62-4.070(3), F.A.C.]

14. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, Boiler 8 shall be tested to demonstrate initial compliance with the emission standards for ammonia slip, CO, NOx, PM, SO_2, VOC, and opacity. The tests shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after the initial startup. Subsequent compliance stack tests for each of these pollutants shall also be conducted during each federal fiscal year (October 1^{st} to September 30^{th}). Tests shall be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate when firing only bagasse. CO CEMS data shall be reported for each run of the required test for VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for CO and NOx emissions may be used to demonstrate compliance with the initial stack test standards for these pollutants. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment. *{Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}* [Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

15. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
CTM-027	Measurement of Ammonia Slip *{Note: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}*
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NOx Emissions (Instrumental)
9	Visual Determination of the Opacity
10	Measurement of Carbon Monoxide Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NOx, PM, and SO_2 Emission Rates
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

MONITORING REQUIREMENTS

16. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (° F), steam pressure (psig), and steam production rate (lb/hour). Records shall be maintained on site and made available upon request. [Design; Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

17. Fuel Monitoring: The permittee shall monitor each fuel in accordance with the following provisions. [Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

    a. *Distillate Oil*: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain an oil flow meter with integrator. At the end of each day that oil is fired, the oil flow meter integrator shall be read and recorded in a written log. Initial compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority. During each federal fiscal year (October 1st to September 30th), the permittee shall take a sample from the storage tank and analyze for the fuel sulfur content. Sampling for the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90 (or more recent versions when available). For each delivery of distillate oil, the permittee shall maintain a permanent record of each certified fuel sulfur analysis provided by the fuel vendor. Records shall specify the date of delivery, the gallons delivered, the fuel sulfur content and test method.

    b. *Bagasse*: A representative sample of bagasse shall be taken each calendar quarter and analyzed for the following: heating value (Btu/lb, as fired and dry); moisture content (percent by weight); sulfur content (percent by weight, dry); and ash content (percent by weight, dry). Records of the results of these tests shall be maintained on site and made available upon request.

18. CEMS: The permittee shall install, calibrate, operate and maintain continuous emission monitoring systems (CEMS) to measure and record concentrations of CO, NOx, and O_2 in the exhaust of Boiler 8 in a manner sufficient to demonstrate continuous compliance with the CEMS standards specified in this permit. The permittee shall notify the Compliance Authority within one working day of discovering emissions in excess of a CEMS standard subject to the specified averaging period. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial stack tests.

    a. *CO Monitors.* The CO monitor shall be installed to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have automatic dual span capabilities with maximum span values of 1000 ppmvd and 10,000 ppmvd.

    b. *NOx Monitors.* The NOx monitor shall be installed to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have a maximum span value of 250 ppmvd.

    c. *Diluent Monitors.* An oxygen monitor shall be installed at each CO and NOx monitor location to correct measured CO and NOx emissions to the required oxygen concentrations. The O_2 monitor shall meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

d. *1-Hour Averages (CO and NOx).* 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of "ppmvd @ 7% oxygen".

e. *24-Hour Averages (CO)*: Each 24-hour block shall begin at midnight of each operating day and shall be determined by averaging 24 consecutive 1-hour averages for each operating day. If the boiler operates less than 24 hours during the block, the 24-hour average shall be determined by averaging the available valid 1-hour block averages for actual boiler operation. Final results shall be recorded in terms of "ppmvd @ 7% O_2" and "pounds per day". [Rule 62-212.400(BACT), F.A.C.]

f. *30-Day Averages (NOx)*: The 30-day rolling average shall be determined by averaging all 1-hour averages for 30 successive boiler operating days. A boiler operating day begins and ends at midnight of each day and includes any day that fuel is combusted. Final results shall be recorded in terms of "ppmvd @ 7% O_2".

g. *Annual Averages (CO)*: The 12-month rolling total shall be determined by summing the daily CO mass emission rates (pounds per day) for the 12-month period. The result shall be reported in terms of "tons per consecutive 12 months".

h. *Data Exclusion.* Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 12 in this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

i. *Availability.* Monitor availability for each CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

19. COMS: In accordance with the provisions of NSPS Subparts A and Db, the permittee shall install, operate, and maintain a continuous opacity monitoring system (COMS) to demonstrate continuous compliance with the opacity standard. *{Permitting Note: NSPS Subpart Db establishes an opacity standard for the firing of "coal, oil, wood or mixtures of these fuels", which applies at all times except startup, shutdown, or malfunction. Therefore, the COMS is required by NSPS Subpart Db when Boiler 8 fires distillate oil alone or in combination with bagasse. See Appendix D of this permit for additional related NSPS requirements.}* [Rule 62-204.800, F.A.C.; 40 CFR 60.48b(a)]

20. Alternate Opacity Monitoring Plan: With prior written approval from EPA Region 4, the permittee may employ the following alternate sampling procedures in lieu of the requirement to install and operate a COMS. The procedures apply to the firing of distillate oil.

    a. A certified EPA Method 9 observer shall perform a twelve-minute opacity test once per daylight shift during the period that the highest distillate oil firing rate occurs.

    b. A certified EPA Method 9 observer shall perform a twelve-minute opacity test when the boiler achieves the normal operational load after a cold boiler startup with distillate oil.

    c. Required observations shall be made in accordance with the provisions of EPA Method 9.

    d. The observer shall maintain a log, which includes all of the information required by EPA Method 9 for each set of observations and the distillate oil firing rate (gph) during the observations.

    e. Within 30 days after each calendar quarter, the permittee shall submit a copy of the observation log to the Compliance Authority for each observation performed during the quarter. The information shall also include a summary of the fuel usage and fuel analysis to verify that Boiler 8 has not exceeded the 10% annual capacity factor limit.

    f. The permittee shall follow the boiler manufacturer's maintenance schedule and procedures to assure that serviceable components are well maintained.

    g. If Boiler 8 exceeds the annual capacity factor limit of 10% for the combustion of distillate oil or is unable to regularly comply with the applicable opacity standard in §60.43b(f) when firing distillate oil, the permittee shall install and operate a COMS to demonstrate compliance with the opacity standards of the permit.

    [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

    {Permitting Note: At the time of the final permit issuance, EPA Region 4 had not yet approved the above alternate sampling procedure.}

21. ESP Monitoring Plan: To ensure proper functioning and effective performance of the electrostatic precipitator (ESP), the permittee shall submit a final ESP Monitoring Plan in accordance with the following requirements.

    a. *Testing Program*: Within 90 days of the initial compliance stack tests, the permittee shall complete a testing program designed to establish the minimum total secondary power input to the ESP that indicates effective performance.

    b. *Monitoring Provisions*: As part of the application for a Title V air operation permit, the permittee shall submit a final ESP Monitoring Plan that includes the following:

        1) Based on the testing program, the plan shall specify the minimum total ESP secondary power input requirement (kW, 1-hour block average) that indicates effective performance.

        2) The plan shall identify procedures to continuously monitor the ESP secondary voltage and secondary current, which will be used to calculate and record the total ESP secondary power input.

3) Continuous measurements shall be averaged into 15-minute blocks, which in turn will be averaged into 1-hour blocks beginning at the top of each hour.

4) Excursions below the minimum level specified require investigation and corrective action.

5) The proposed plan shall incorporate appropriate QA/QC requirements to ensure valid data.

[Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

22. <u>SNCR Urea Injection</u>: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea injection rate for the SNCR system. The permittee shall document the general range of urea flow rates required to meet the NOx standard over the range of load conditions by comparing NOx emissions with urea flow rates. During NOx monitor downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. [Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

23. <u>Wet Cyclone</u>: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain the following equipment on each wet cyclone: flow meter to monitor the water flow rate (gph) and a manometer (or equivalent) to monitor the pressure drop (inches of water). At least once each 8-hour work shift, the flow rate and pressure drop shall be observed and recorded in a written log. [Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

RECORDS AND REPORTS

24. <u>Stack Test Reports</u>: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (MMBtu/hour), bagasse firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

25. <u>Monthly Operations Summary</u>: By the tenth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month of operation: hours of operation, distillate oil consumption, pounds of steam per month, and the updated 12-month rolling totals for each of these operating parameters. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. <u>Quarterly CO and NOx Emissions Report</u>: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, and CEMS systems monitor availability for the previous quarter. See Appendix G of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

B. Bagasse Handling System

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
027	Bagasse Handling System

EQUIPMENT

1. Modification of Existing System: The permittee is authorized to modify the existing bagasse handling system to accommodate the additional bagasse required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed bagasse to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the bagasse throughput of the handling system. [Design; Rule 62-212.400(2)(e) and (g), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive particulate matter, bagasse conveyors shall be enclosed. Dust collectors shall be installed on the conveyor transfer points. The preliminary design for the bagasse conveyor dust collection system is based on the following specifications.

Dust Collector	Manufacturer	Model No.	Flow Rate (acfm)	Outlet (grains/afc)	Approximate Outlet Height (feet)
1	Prime Systems	BV-6X8-120	3550	0.02	57
2	Prime Systems	BV-8X8-120	3100	0.02	62
3	Prime Systems	BV-8X7-120	4725	0.02	61
4	Prime Systems	BV-6X8-120	3550	0.02	57
5	Prime Systems	BV-6X8-120	3550	0.02	57

{Permitting Note: This system has previously been permitted and is under construction. The original plan called for the installation of six dust collectors. With the elimination of transfer belt conveyor No. 2, only the five duct collectors described above will be installed.} [Design]

EMISSIONS STANDARDS

3. Opacity: As determined by EPA Method 9, there shall be no visible emissions (≤ 5% opacity) from the dust collector outlets. [Rule 62-212.400(5)(c), F.A.C.]

TESTING REQUIREMENTS

4. Opacity Tests: Within 180 days of completing construction of the bagasse handling system and during the sugar mill season, an initial test shall be conducted in accordance with EPA Method 9 to demonstrate compliance with the opacity standard. Tests shall be conducted while the sugar mill and boilers are in normal operation. Each test shall be at least 30 minutes in duration. Subsequent tests shall be repeated for each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the opacity standard. [Rules 62-212.400(5)(c) and 62-297.310(7)(a)4, F.A.C.]

REPORTS

5. Test Report: Within 45 days of conducting an opacity test, the permittee shall submit a report to the Compliance Authority summarizing the results of the test. [Rule 62-297.310(8), F.A.C.]

Contents

Citation Formats

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7 or §60.7]

Means: Title 40, Part 60, Section 7

General Conditions

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

General Conditions

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Common Requirements

{Permitting Note: Unless otherwise specified by permit, the following conditions apply to all emissions units and activities at this facility.}

Definitions

1. Excess Emissions: Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot-blowing, load changing or malfunction. [Rule 62-210.200(106), F.A.C.]

2. Shutdown: The cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

3. Startup: The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(246), F.A.C.]

4. Malfunction: Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

Emissions and Controls

5. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

7. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

8. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

9. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A:C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

10. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

11. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

12. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as confining, containing, covering, and/or applying water to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input: *{Permitting Note: Rule 62-296.405(2), F.A.C. specifies that that new units are subject to the applicable standards in NSPS Subparts D or Da for opacity, particulate matter, sulfur dioxide, and nitrogen oxides. However, NSPS Subpart D is not applicable because the project is also subject to the more recent NSPS Subpart Db, which states that such units are not also subject to NSPS Subpart D. See §60.40b(j) in Appendix D. NSPS Subpart Da is not applicable to this project because the boiler is not an electric utility steam generating unit.}*

15. Carbonaceous Fuel Burning Equipment: Rule 62-296.410(2)(b), F.A.C. establishes the following standards for new emissions units with burners of a capacity equal to or greater than 30 MMBtu per hour total heat input.

    a. *Visible Emissions*: 30 percent opacity except that 40 percent opacity is permissible for not more than two minutes in any one hour.

    b. *Particulate Matter*: 0.2 pounds per MMBtu of heat input of carbonaceous fuel plus 0.1 pounds per million Btu heat input of fossil fuel.

{Permitting Note: The BACT standards specified in the permit are much more stringent than the standards specified in Rules 62-296.405(2) and 62-296.410(2)(b), F.A.C.}

TESTING REQUIREMENTS

16. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

17. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    [Rule 62-297.310(4), F.A.C.]

20. Determination of Process Variables

    a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

21. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

22. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

23. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

24. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

    1. The type, location, and designation of the emissions unit tested.
    2. The facility at which the emissions unit is located.
    3. The owner or operator of the emissions unit.
    4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
    5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
    6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
    7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
    8. The date, starting time and duration of each sampling run.
    9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
    10. The number of points sampled and configuration and location of the sampling plane.
    11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
    12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

25. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. Information recorded and stored as an electronic file shall be made available within at least three days of a request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

26. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

NSPS Requirements

The following emissions unit is subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler firing bagasse rated at a maximum continuous steam production rate of 500,000 pounds per hour (24-hour average)

40 CFR 60, Subpart A - NSPS General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units

Boiler 8 shall comply with the applicable requirements of Subpart Db in 40 CFR 60, which are adopted by reference in Rule 62-204.800(7)(b), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and related requirements are shown in italics immediately following the pertinent section. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.}

§60.40b Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu/hour.

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(g) In delegating implementation and enforcement authority to a State under Section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State: (1) §60.44b(f); (2) §60.44b(g); and (3) §60.49b(a)(4).

{Permitting Note: NSPS Subpart Db applies because the maximum heat input from oil firing is 562 MMBtu per hour for the new unit.}

§60.41b Definitions

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydro-desulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference - see §60.17).

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

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

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

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

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

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

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

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

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

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 0.5 lb/million BTU heat input.

§60.42b Standard for Sulfur Dioxide

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil (0.5% sulfur by weight). The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emission standard for the boiler flue gas or a percent reduction requirement because the permit restricts distillate oil to no more than 0.05% sulfur by weight. The permit includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.43b Standard for Particulate Matter

(b) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 0.10 lb/million Btu heat input.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

{Permitting Note: NSPS Subpart Db does not impose a particulate matter emission standard for the boiler flue gas because no equipment will be necessary to reduce SO_2 emissions. The permit limits stack opacity to this level or less.}

§60.44b Standard for Nitrogen Oxides

(a) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

(1) Natural gas and distillate oil:

(i) Low heat release rate: 0.10 lb/million BTU of heat input (expressed as NO_2), or

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixture of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis.

{Permitting Note: Boiler 8 is a low heat release rate boiler (20,497 Btu/ft^3 on bagasse and 11,184 Btu/ft^3 on distillate oil) and will fire only distillate oil during a cold startup. However, such a startup will last only a few hours before bagasse is introduced. As described in paragraph (c) above, NSPS Subpart Db does not impose a NOx standard for the boiler flue gas when firing a combination of bagasse and distillate oil because the permit limits distillate oil firing to an annual capacity factor of no more than 10%.}

§60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(j) The owner or operator of an affected facility that combusts very low sulfur oil ($\leq$ 0.5% sulfur by weight) is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emissions limit for the boiler flue gas because the boiler will combust only distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(a) The opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under §60.44b apply at all times.

(d) To determine compliance with the particulate matter and emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8 using the following procedures and reference methods: (7) Method 9 is used for determining the opacity of stack emissions.

{Permitting Note: NSPS Subpart Db imposes only an opacity standard because the boiler is restricted to an annual capacity factor of no more than 10% for firing oil. The permit requires testing in accordance with EPA Method 9.}

§60.47b Emission Monitoring for Sulfur Dioxide

(f) The owner or operator of an affected facility that combusts very low sulfur oil (≤ 0.5% sulfur by weight) is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides

(a) The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

{Permitting Note: In lieu of the continuous opacity monitoring requirements, the permittee has requested approval from EPA Region 4 for an alternate procedure that includes additional EPA Method 9 observations when firing oil and monitoring the total ESP secondary voltage as an indicator of proper functioning and effective performance of the ESP.}

§60.49b Reporting and Recordkeeping Requirements

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

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

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i), and

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

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §60.42b, §60.43b, and §60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in Appendix B.

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

{Permitting Note: In lieu of the COMS, the permittee has requested approval from EPA Region 4 for an alternate procedure that includes additional Method 9 observations when firing oil and monitoring the total ESP secondary voltage as an indicator of proper functioning and effective performance of the ESP.. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur.}

Project Description

U.S. Sugar Corporation proposes to install a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 550,000 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. The maximum continuous steam production is 500,000 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour averages). Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used fire the primary fuel of bagasse. Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. The project will also modify the existing bagasse handling system to accommodate the additional bagasse required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed bagasse to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the bagasse throughput of the bagasse handling system.

Air Pollution Control Equipment

Boiler 8: Particulate matter will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP) with approximately a 99% reduction. Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system (~ 50% reduction). Other NOx reduction techniques include low NOx burners for distillate oil, overfire air, and low nitrogen fuels. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide.

Bagasse Handling System: To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Pollutant	Standards - Stack Test [a]	Standards – CEMS [b]
EU-027: Bagasse Handling System		
Opacity [c]	There shall be no visible emissions (≤ 5% opacity) from the dust collector outlets.	
EU-028: Boiler 8		
CO [d]	0.38 lb/MMBtu (Equivalent: 363 ppmvd @ 7% O_2)	1285 tons per consecutive 12 months, (rolling total)
NOx	0.14 lb/MMBtu (Equivalent: 81 ppmvd @ 7% O_2)	81 ppmvd @ 7% O_2, 30-day rolling average (normal operation) 162 ppmvd @ 7% O_2, average during startup or shutdown
PM	0.026 lb/MMBtu	Not Applicable
SO_2 (Surrogate for SAM)	0.06 lb/MMBtu (Equivalent: 25 ppmvd @ 7% O_2)	Not Applicable
	Fuel Specification: Distillate oil shall be new No. 2 oil containing no more than 0.05% sulfur by weight.	
VOC	0.05 lb/MMBtu (Equivalent: 111 ppmvd @ 7% O_2)	Not Applicable
Opacity [c]	During normal operation, stack opacity shall not exceed 20% based on a 6-minute block average. During startup or shutdown, stack opacity shall not exceed 20% based on a 6-minute block average except for one 6-minute block per hour that shall not exceed 27%.	

a. These standards apply when firing bagasse, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The permit also establishes maximum hourly mass emission rates based on operation at permitted capacity. Compliance with the standards based on stack tests shall be determined by the following EPA stack test methods: CO (Method 10); NOx (Method 7E); PM (Method 5); SO_2 (Method 6C); VOC (Methods 18 and 25A, as propane). Compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

b. These standards apply when firing bagasse, distillate oil, or a combination of these fuels and under all load conditions. Compliance with the CO and NOx CEMS-based standards shall be demonstrated by data collected from the required continuous emissions monitoring systems (CEMS) required for these pollutants. The permit allows specific NOx CEMS data to be excluded from the compliance determination (30-day rolling average) when the SNCR system is not functioning due to startup, shutdown, or malfunction. The alternate NOx standard then applies, which is an average of the CEMS data for the period of startup or shutdown. The CO monitor shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The NOx monitor shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. An oxygen monitor shall be installed and meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60 to correct the CO and NOx emission rates.

c. NSPS Subpart Db requires a Continuous Opacity Monitoring System (COMS) for new industrial boilers firing "coal, oil, wood or mixtures of these fuels", which applies at all times except startup, shutdown, or malfunction. Therefore, the COMS is required by NSPS Subpart Db when Boiler 8 fires distillate oil alone or in combination with bagasse. In lieu of the COMS requirements for Boiler 8, the permittee has requested approval from EPA Region 4 for an alternate sampling procedure that includes additional EPA Method 9 observations when firing oil and monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP. If approved by EPA Region 4, the permittee may use the alternate sampling procedure.

d. Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The permit requires the permanent shutdown of Boiler 3 prior to operating new Boiler 8.

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for this project.

Determination By:

(DRAFT)

______________________________ __________

Jeff Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

______________________________ __________

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

______________________________ __________

Michael G. Cooke, Director (Date)
Division of Air Resources Management

Good Combustion and Operating Practices

The determination of Best Available Control Technology (BACT) for emissions of carbon monoxide and volatile organic compounds (VOC) from Boiler 8 relied on an efficient boiler design and good combustion and operating practices. To the extent practicable, the permittee shall employ the following procedures to minimize emissions and promote good combustion and pollution control.

Startup and Shutdown

1. Training: All operators and supervisors shall be properly trained to operate and maintain Boiler 8 as well as the pollution control and monitoring equipment in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions during startups, shutdowns, and malfunctions.
2. Boiler Startup: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately 4 to 5 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse will be fed until a fire is established across the entire grate. The full steaming rate can be reached about 30 to 60 minutes after first feeding bagasse.
3. PM Controls: The wet cyclone collectors will be activated before firing any fuel. Prior to activation, the ESP will be purged with ambient air for about 30 to 60 minutes. Distillate oil may be fired during startup prior to energizing the electrostatic precipitator (ESP). The ESP will be on line and functioning properly before any bagasse is fired. The ESP will remain on line until the bagasse feed has stopped and combustion on the grate is substantially complete.
4. NOx Controls: When the SNCR manufacturer's minimum operating temperature requirement is met, the SNCR system will be activated for NOx control. For a cold startup, this temperature is generally reached within 4 - 5 hours of initial distillate oil firing. During normal operation, the SCNR control system will automatically adjust the urea injection rate and zones to meet the specified NOx standard based on the current urea injection rate, boiler load, furnace temperature, and NOx emissions. During shutdown, the SNCR system shall remain operational until the operating temperature drops below the minimum requirement.
5. Good Combustion Practices: To the extent practicable, the permittee shall maintain the following flue gas levels as indicators of good combustion:

   a. *Oxygen*: The permittee shall install, maintain, and operate a flue gas oxygen monitor on Boiler 8. When firing bagasse during normal operation, the flue gas oxygen content is expected to range from 3% and 4%. High fuel moisture, high ash content, and low load conditions may result in higher flue gas oxygen contents (5% - 6%). When firing only distillate oil, the flue gas exhaust oxygen content is expected to range from 8% and 9% due to tramp air required for cooling of the stoker, pneumatic distributors, and overfire air nozzles. Operators shall ensure that the flue gas oxygen content is sufficient for good combustion.

   b. *Carbon Monoxide (CO)*: Carbon monoxide is an indicator of incomplete fuel combustion. In addition to insufficient oxygen, high fuel moisture, high ash content and low load conditions may result in elevated levels of carbon monoxide. When firing bagasse during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen based on a 24-hour average, excluding emissions during startup and shutdown. The required carbon monoxide CEMS shall report daily CO emission averages in these units. The operator shall use the measured CO emissions at the stack as an indicator of the combustion efficiency and adjust boiler operating conditions as necessary. *{Permitting Note: The stack exhaust is expected to be 1% - 2% (oxygen content) higher than the boiler exhaust due to infiltration from the entire system.}*

   When firing carbonaceous fuels such as bagasse, many factors may affect efficient combustion. The above levels represent adherence to good combustion practices under normal operating conditions. Operation outside these levels is not a violation in and of itself. Repeated operation beyond these levels without taking corrective actions to regain good combustion could be considered "circumvention" in accordance with Rule 62-210.650, F.A.C.
6. Boiler Shutdown: To initiate shutdown, the bagasse fuel feed is terminated. The SNCR systems shall remain functional until operating conditions fall outside of the manufacturer's recommendations. The wet cyclone collectors and ESP shall continue to operate until bagasse combustion on the fuel grate is substantially complete.

Quarterly CO and NOx Emissions Report

Current Title V Permit No. ____________________

Facility Name	**ARMS ID No.**	**ARMS EU ID No.**
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	0510003	028

Emissions Unit Description

Boiler 8 is a spreader stoker boiler with maximum continuous steam rate of 500,000 lb/hour. Control equipment includes:

- CO/VOC – Efficient combustion design and good operating practices
- NOx – Low NOx oil burners and selective non-catalytic reduction (SNCR) system
- PM/PM10 – Wet cyclone collectors and electrostatic precipitators

Primary Fuel	**Auxiliary Fuels**
Bagasse – Fibrous plant material remaining after sugarcane is milled	Distillate oil (≤ 0.05% sulfur by weight)

Year	**Calendar Quarter of Operation Covered** ***(Check one.)***	**Unit Operation in Calendar Quarter**
	___ 1 ___ 2 ___ 3 ___ 4	________ hours

Continuous Emissions Monitoring System (CEMS) Information

Pollutant Monitored: _____ CO _____ NOx   Manufacturer: ____________________

Date of last certification or audit: ____________________   Model No. ____________________

Emission Data Summary

1. Standard: ____________________
2. Hours of excess emissions in reporting period due to:
   a. Startup/shutdown .... _____
   b. Control equipment problems .... _____
   c. Process problems .... _____
   d. Other known causes .... _____
   e. Unknown causes .... _____
2. Total hours of excess emissions .... _____
3. (Total hours of excess emissions) / (Total hours of source operating time) x (100%) ..... _____

Note: Report "excess emissions" for any emission averages that are in excess of a permitted emissions standard and averaging period.

CEMS Performance Summary

1. Hours of CEMS downtime in reporting period due to:
   a. Monitor equipment malfunctions .... _____
   b. Non-monitor equipment malfunctions .... _____
   c. Quality assurance calibration .... _____
   d. Other known causes .... _____
   e. Unknown causes .... _____
2. Total hours of CEMS downtime .... _____
3. (Total hours of CEMS downtime) / (Total hours of source operating time) x (100%).... _____

If monitor availability is not at least 95%, provide a report identifying the problems and a plan of corrective actions that will be taken to achieve 95% availability

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startups .... _____   c. Malfunctions .... _____
   b. Shutdowns .... _____   d. Total .... _____
3. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
4. On a separate page, describe any changes to the CEMS, process equipment, or control equipment during last quarter.

Emission Rates

On a separate page, report the actual emissions for: each rolling 12-month total (tons) of CO emissions for each month in the quarter, and each 30-day rolling NOx average (ppmvd @ 7% oxygen) for each compliance period in the quarter.

Certification

I certify that the information contained in this report is true, accurate, and complete.

Print Name / Title	**Signature / Date**

SENDER: *COMPLETE THIS SECTION*	*COMPLETE THIS SECTION ON DELIVERY*
■ Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. ■ Print your name and address on the reverse so that we can return the card to you. ■ Attach this card to the back of the mailpiece, or on the front if space permits.	A. Received by (*Please Print Clearly*) L Harris B. Date of Delivery 9-29-03 C. Signature X L Harris ☐ Agent ☐ Addressee D. Is delivery address different from item 1? ☐ Yes If YES, enter delivery address below: ☐ No
1. Article Addressed to: Mr. William A. Raiola V.P. of Sugar Processing Operations United States Sugar Corporation Post Office Drawer 1207 Clewiston, FL 33440-1207	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? (*Extra Fee*) ☐ Yes
2. 7001 0320 0001 3692 6068	

PS Form 3811, July 1999   Domestic Return Receipt   102595-99-M-1789

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

7001 0320 0001 3692 6068

OFFICIAL USE

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To William A. Raiola

Street, Apt. No.; or PO Box No. PO Drawer 1207

City, State, ZIP+4 Clewiston, FL 33440-1207

PS Form 3800, January 2001   See Reverse for Instructions

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief
Bureau of Air Regulation

THROUGH: Al Linero, Manager *AA* 9/18
New Source Review Section

FROM: Jeff Koerner, New Source Review Section *JK*

DATE: September 18, 2003

SUBJECT: Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft PSD Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is October 3, 2003. I recommend your approval of the attached Draft Permit for this project.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project

PROJECT DESCRIPTION

The United States Sugar Corporation (U.S. Sugar) operates the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The facility currently has five existing boilers that primarily fire bagasse to provide steam for the mill and refinery. U.S. Sugar proposes to construct a new spreader stoker boiler (Boiler 8) with a maximum continuous steam production rate of 500,000 pounds per hour to support the sugar mill and refinery operations of the existing plant. It will purportedly be the largest bagasse-fired boiler in the United States. It will also fire distillate oil as a restricted alternate fuel for startup and supplemental uses. As part of the project, existing Boiler 3 will be permanently shut down and the bagasse handling system will be modified to accommodate Boiler 8. Actual emissions of several small existing miscellaneous activities in the mill and refinery may also occur.

The project is subject to PSD preconstruction review for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. The draft permit includes emissions standards that represent the Department's preliminary determination of the Best Available control Technology (BACT) for each PSD-significant pollutant. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design along with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery J. Koerner 9-18-03

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441