Florida Department of Environmental Protection

Memorandum

TO: Michael G. Cooke, Division of Air Resource Management

THRU: Trina Vielhauer, Bureau of Air Regulation
Al Linero, Air Permitting South Program

FROM: Jeff Koerner, Air Permitting South Program

DATE: October 20, 2004

SUBJECT: Project No. 0510003-024-AC
Revised Air Permit No. PSD-FL-333A
U. S. Sugar Corporation – Clewiston Sugar Mill
Shakedown Provisions

The Final Permit for this project is attached for your approval and signature, which revises the original PSD air construction permit for new Boiler 8 at U.S. Sugar's Clewiston sugar mill and refinery. This existing facility is located in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The new boiler is currently under construction and will be the largest sugar mill boiler in the country. 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. The revised permit addresses an appropriate shakedown period for the boiler/SNCR system, authorizes brief periods of operation without the SNCR functioning for purposes of gathering uncontrolled NOx emissions, and allows the firing of de-watered DAF filter material consisting mostly of bagasse.

The Department distributed an "Intent to Issue Permit" package on September 13, 2004. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on September 30, 2004. The Department received the proof of publication on October 11, 2004. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

Day #90 is January 3, 2005. I recommend your approval of the attached Final Permit for this project.

Mike –
Yes. This is an impressive project -- esp. for the sugar industry!
Trina

Attachments

SENDER: *COMPLETE THIS SECTION*

- 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.

1. Article Addressed to:

Mr. William A. Raiola, V.P. of Sugar
Processing Operations
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (*Printed Name*)

C. Date of Delivery 11/8/04

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

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Mr. William A. Raiola, V.P. of Sugar
Processing Operations
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

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FINAL DETERMINATION

PERMITTEE

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

Authorized Representative:

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

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation - Air Permitting South Program
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Air Permit No. PSD-FL-333A
Project No. 0510003-024-AC
U.S. Sugar Clewiston Sugar Mill and Refinery
Boiler 8 Project

In accordance with original Permit No. PSD-FL-333, Boiler 8 is being constructed at 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. This current permitting action revises the original air construction permit for Boiler 8 to specifically address the shakedown period for the boiler/SNCR system, authorized periods of uncontrolled NOx emissions, and the firing of de-watered DAF filter material.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on September 13, 2004. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on September 30, 2004. The Department received the proof of publication on October 11, 2004. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

No comments on the Draft Permit were received from the public, the Department's South District Office, the EPA Region 4 Office, or the National Park Service. With regard to the DAF filter material described in Appendix I, the applicant requests that the fuel sulfur restriction ($\leq$ 0.05% sulfur by weight) be removed. The applicant points out that fuel oil from other boilers could also be included in the DAF filter material. The other boilers are authorized to fire fuel oil containing sulfur as high as 2.5% by weight. In addition, the applicant notes that any sulfur dioxide emissions generated from the DAF filter material would be minimal. The Department agrees that the restriction on fuel sulfur for the small amounts of DAF filter material is unnecessary. Fuel sulfur contents are already limited in the existing air construction and operation permits for each boiler. The requirement was removed from the permit.

The Department also revised the first two sentences under the "Statement of Basis" to better describe the project.

CONCLUSION

Only minor revisions were made to correct typographical errors. The final action of the Department is to issue the permit with the changes described above.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333A
Project No. 0510003-024-AC
Revised Permit

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

Enclosed is Final Air Permit No. PSD-FL-333A, which revises the original air construction permit to specifically address the shakedown period for the boiler/SNCR system, authorized periods of uncontrolled NOx emissions, and the firing of de-watered DAF filter material. The new equipment will be installed at 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. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

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 Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/04/04 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.

(Clerk) 11/04/04 (Date)

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

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-333A
Project No. 0510003-024-AC
Facility ID No. 0510003
SIC Nos. 2061, 2062
Permit Expires: July 1, 2007

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

Boiler 8 is being constructed under original Permit No. PSD-FL-333 issued on November 20, 2003. It will be a new bagasse-fired boiler with a maximum heat input rate of 1030 MMBtu/hour. This permitting action is a revision of the original air construction permit to specifically address the shakedown period for the boiler and SNCR system, authorized periods of uncontrolled NOx emissions, and the firing of de-watered DAF filter material. The revised 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

Michael G. Cooke, Director
Division of Air Resource Management

11/3/04
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 (≤ 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 facility as defined in Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63.

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. Summary of Final BACT Determinations

Appendix F. Good Combustion and Operating Practices

Appendix G. Quarterly CO and NOx Emissions Report

Appendix H. Shakedown Period

Appendix I. De-Watered DAF Filter Material

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. Permit No. PSD-FL-333A revises original Permit No. PSD-FL-333 to specifically address the shakedown period for the boiler and SNCR system, authorized periods of uncontrolled NOx emissions, and the firing of de-watered DAF filter material.

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.]

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 no more 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 is 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 of nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO2), 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); the federal New Source Performance Standards (NSPS) of Subpart Db (industrial boilers) in 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C.; and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) of Subpart DDDDD (industrial boilers) in 40 CFR 63.}

EQUIPMENT

1. Shutdown of Boiler 3: No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of first fire in Boiler 8. Shakedown of the boiler is defined in Appendix H of this permit. During the authorized shakedown period:
   a. Boiler 8 may operate with the other existing boilers to ensure proper integration with the sugar mill and refinery. Any fuel oil fired in Boilers 1, 2, and 3 shall contain no more than 1.6% sulfur by weight.
   b. Boilers 3 and 8 may operate concurrently for no more than 90 individual days during which the combined steam production from Boilers 3 and 8 shall not exceed a daily average of 250,000 pounds per hour. After first fire and shakedown of Boiler 8, Boiler 3 shall be permanently shutdown prior to commencement of commercial operation of Boiler 8 or after completion of the crop season, whichever occurs first. For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September.

No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of the permanent shutdown of Boiler 3 and of beginning commercial operation of Boiler 8. *{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. The authorized shakedown period provides a reasonable period to start up the newly designed Boiler 8, test operations, and make necessary adjustments. A limited amount of concurrent operation is allowed because Boiler 8 is replacing Boiler 3 and must be fully tested during the crop season.}* [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 design conditions of 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. Urea injection rates and zones will be determined based on parameters such as 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. In addition, incidental amounts of de-watered DAF filter material may be commingled with bagasse and

fired in Boiler 8 in accordance with the requirements in Appendix I of this permit. [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. The mass emission rates (pounds per hour) are based on the maximum 24-hour heat input rate. 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): To the extent practicable, short term emissions of carbon monoxide shall be controlled by implementing the good combustion and operating practices identified in Appendix F. *{Permitting Note: The Department intends to re-open this permit and include the 40 CFR 63 Subpart DDDDD requirements as appropriate.}* [Rules 62-4.070(3), 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 standard is an "initial demonstration standard" intended to show the capabilities of the SNCR system as designed. After the initial compliance test, subsequent compliance shall be demonstrated with the long-term CEMS-based standard specified in Condition 8b.}* [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 0.38 lb/MMBtu during any consecutive 12 months excluding periods of startup, shutdown, and malfunction. As determined by CEMS data, CO emissions shall not exceed 1285 tons during any consecutive 12 months including periods of startup, shutdown, and malfunction. *{Permitting Note: Compliance with the annual mass emission 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 0.14 lb/MMBtu based on a 30-day rolling average. [Rule 62-212.400(5)(c), F.A.C.]

{Permitting Note: Appendix H of this permit specifies additional requirements regarding the initial shakedown period and initial demonstration of compliance for the CEMS-based standards.}

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. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [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*: Provided best operational practices are used to minimize emissions, CO CEMS data collected during startups, shutdowns, and malfunctions may be excluded from the determination of compliance with the CO standard based on heat input rate (lb/MMBtu, 12-month rolling average). However, all valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total).

b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, malfunction, and authorized periods of uncontrolled NOx monitoring 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 (eight 15-minute CEMS blocks or quadrants of an hour). The permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

   4) For two hours each month, the permittee may operate the boiler without the SNCR system in order to collect uncontrolled NOx emissions data with the CEMS. For purposes of collecting uncontrolled NOx emissions data to adjust the SNCR system, excluded data shall not exceed two, 1-hour values during any calendar month. *{Permitting Note: Based on the final design specifications, uncontrolled NOx emissions are expected to be 0.30 lb/MMBtu. Uncontrolled NOx data collected during these periods will be used to adjust the SNCR system as necessary.}*

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. This alternate opacity standard does not impose a separate annual testing requirement.

CO and NOx CEMS data excluded due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring shall be summarized and reported in the "Quarterly CO and NOx Emissions Report" required by this permit. *{Permitting Note: Allowances for these periods are provided for carbon monoxide and nitrogen oxides because compliance is continuously demonstrated by CEMS data. Similarly, an alternate standard is identified for opacity during startup and shutdown because compliance is readily observable. As sulfur dioxide emissions are a function of the fuel sulfur, it is not expected that startups or shutdowns would cause excess emissions of this pollutant. It is possible that emissions of particulate matter and volatile organic compounds could exceed the permit standards in terms of "lb/MMBtu" during startups and shutdowns. However, the Department has good reason to believe that the mass emission rates of these pollutants (lb/hour) will not exceed the specified standards due to reduced loads and fuel firing rates. In any case, the specified test methods are generally applicable only during steady-state operation. Therefore, no alternate emissions standards are specified and compliance shall determined by the test methods and procedures specified in this permit.}*

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 boiler steam conditions and production rate shall be monitored and recorded during the test. The bagasse fuel firing rate (tons per hour) shall be calculated and recorded based on the steam parameters. 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:

(a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency of 62%. Results of the test shall be submitted to the Department within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. [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, 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 ammonia slip, PM, SO_2, VOC, and opacity shall also be conducted during each federal fiscal year (October 1st to September 30th). 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 tests for NOx and VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for NOx emissions may be used to demonstrate compliance with the initial stack test standards for this pollutant. 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 "lb/MMBtu".

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 "lb/MMBtu" 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 "lb/MMBtu".

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. Alternate Opacity Monitoring Plan: Based on written approval from EPA Region 4, the permittee shall 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 in accordance with the provisions of NSPS Subparts A and Db to demonstrate compliance with the opacity standards of the permit.

    {Permitting Note: In a letter dated September 22, 2003, EPA Region 4 approved the above Alternate Opacity Monitoring Plan.} [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

20. 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, 3-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 and 3-hour block averages beginning at the top of each hour, excluding monitoring malfunctions, associated repairs, and required QA/QC activities.

        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.]

21. SNCR Urea Injection: 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.]

22. Wet Cyclone: 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

23. Stack Test Reports: 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), calculated bagasse firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

24. Monthly Operations Summary: 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.]

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled NOx emissions monitoring and CEMS systems monitor availability for the previous quarter. If CO or NOx CEMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. 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.]

FEDERAL REQUIREMENTS

26. NSPS Subpart Db: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix D of this permit summarizes these requirements.

27. NESHAP Subpart DDDDD: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63 for "Industrial/Commercial/Institutional Boilers and Process Heaters". *{Permitting Note: The final rule for Subpart DDDDD was not yet published in the Federal Register when draft permit for this revision was issued. The final rule does not become effective until November 11, 2004. The entire rule is available from EPA or can be downloaded from the Department's web site at "http://www.dep.state.fl.us/air/permitting/writertools/t3neshap.htm".}*

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 ($\leq$ 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 (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).
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.

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. *{Not applicable; see "Permitting Note" at end of section.}*

(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)

{Not applicable; see "Permitting Note" at end of section.}

(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. *{Not applicable; see "Permitting Note" at end of section.}*

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis. *{Not applicable; see "Permitting Note" at end of section.}*

{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 distillate oil during startup or as a supplemental fuel. 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 (≤ 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, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil.}*

§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. *{Not applicable; see "Permitting Note" at end of section.}*

(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 continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing 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. The permit also restricts the firing of distillate oil to an annual capacity factor of no more than 10%.}

Summary of Final BACT Determinations

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]	Good Combustion Practices	0.38 lb/MMBtu, 12-month rolling average 1285 tons per consecutive 12 months, (rolling total)
NOx	0.14 lb/MMBtu {Initial demonstration standard; subsequent compliance based on CEMS.}	0.14 lb/MMBtu, 30-day rolling average
PM	0.026 lb/MMBtu	Not Applicable
SO_2 (Surrogate for SAM)	0.06 lb/MMBtu	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	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: NOx (EPA Method 7E); PM (EPA Method 5); SO_2 (EPA Method 6C); VOC (EPA Methods 18 and

25A, as propane); and opacity (EPA Method 9). 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, malfunction, or authorized periods of uncontrolled NOx monitoring. 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, EPA Region 4 approved (September 22, 2003) an alternate sampling procedure that includes additional EPA Method 9 observations when firing distillate oil. In addition, the draft permit requires monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP.

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 the commercial operation of 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 the original project.

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: _____ e. Total _____
   b. Shutdowns: _____ d. Uncontrolled NOx Monitoring: _____
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**

Shakedown Period

Boiler 8 will be a new type of spreader-stoker specifically designed for the efficient combustion of bagasse. Bagasse is the fibrous byproduct remaining from sugarcane after the milling process. The sugarcane milling season runs from October through April. The proposed startup date for the new boiler is January of 2005, which is approximately halfway through the sugarcane milling season. It is expected that a short, initial shakedown period will be necessary for the boiler prior to shakedown of the SNCR system. Although the facility also includes a refinery that operates during the milling off-season, Boiler 8 is not expected to operate much during the off season unless refinery steam demands are high enough to take advantage of large steam production rate from this unit. For these reasons, the Department authorizes the following shakedown period in accordance with the specific conditions, which are in addition to those specified in Section 3 of the permit.

1. Shakedown: Shakedown is limited to the first 360 calendar days after first fire in the boiler and shall not exceed 180 operational days after first fire in the boiler. An "operational day" is any day that Boiler 8 fires any fuel. During shakedown, Boiler 8 shall not operate more than 60 days during the off-season. For this plant, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. Shakedown is complete once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.
2. SNCR System: During the shakedown period, the permittee is authorized to operate the boiler without the SNCR system for purposes of commissioning the boiler and collecting uncontrolled NOx emissions data, provided:
   a. During the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed a total of 240 hours;
   b. After the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed 2 hours each day; and
   c. Notwithstanding the above periods, the operator shall fully utilize the SNCR system to the extent practicable and according to the manufacturer's recommended procedures.
3. CO and NOx CEMS: The CO and NOx CEMS shall be installed and certified within the first 45 operational days of shakedown. CEMS data collected on the first full day following completion of the shakedown period shall be used to begin demonstrating compliance with the CEMS-based emissions standards of the permit.
4. Initial Stack Tests: All initial stack tests required by this permit shall be conducted during the defined shakedown period, but no later than 60 days after achieving the maximum production rate, which is defined as a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average. The permittee shall provide written notification to the Permitting and Compliance Authorities within 10 days of achieving this maximum production rate.

{Permitting Note: After demonstrating compliance and commencing commercial operation, the conditions of Appendix H will become obsolete and need not be included in the Title V air operation permit. The above requirements do not supersede any federal requirements regarding shakedowns for purposes of complying with NSPS or NESHAP regulations. Boiler 8 has a maximum heat input rate greater than 100 MMBtu/hour and is permitted to fire bagasse as the primary fuel with distillate oil as a startup and supplemental fuel. As such, it is an "affected facility" as defined in NSPS Subpart Db of 40 CFR 60. This NSPS regulates emissions of sulfur dioxide, particulate matter, opacity, and nitrogen oxides for the firing of coal, oil, or natural gas (or mixtures of these fuels with other fuels). However, the NSPS standards for particulate matter and sulfur dioxide are not applicable because the new boiler does not employ add-on controls to reduce sulfur dioxide emissions. Instead, sulfur dioxide emissions are limited by the firing of very low sulfur distillate oil and bagasse. In turn, the nitrogen oxide emission standard does not apply because the annual capacity factor for the very low sulfur distillate oil is less than 10% as conditioned by the permit. Only opacity is regulated by NSPS Subpart Db for this new boiler when firing distillate oil. Boiler 8 is also subject to the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.}

De-Watered DAF Filter Material

Description

As a maintenance practice, surface areas at the mill are periodically washed with water to remove debris. The wash water is collected in a series of drains and directed to the Dissolved Aeration Flotation (DAF) system to remove solids. Collected materials include bagasse, used oil, and lime. Bagasse results from spills at the sugar mill and boiler conveyor system. Small amounts of used oil consisting of hydraulic fluid and lubrication oil may be spilled or leaked to the floor from miscellaneous equipment throughout the sugar mill. A conservative estimate of use oil washed to the drains is 500 pounds per day. This used oil does not contain any polychlorinated byphenols (PCBs). Slaked lime is added to the DAF system to act as a coagulant in the clarification process. Drain water passes through the DAF filter and is discharged to the facility's permitted wastewater treatment system.

The DAF filter removes approximately 15,000 pounds of material per day, which consists of roughly 13,500 pounds of liquid per day and 1500 pounds of solids per day. The filter material is then pressed to remove approximately 10,000 pounds of liquids per day, which is also transferred to the permitted wastewater treatment system. The remaining "de-watered" DAF filter material now contains approximately 3000 pounds of water, 1500 pounds of solids (mostly bagasse), and 500 pounds of used oil (assuming all of the oil remains with the solids). Disregarding the used oil, the de-watered DAF filter material would consist mostly of bagasse with a moisture content of about 65% by weight. The sugar mill boiler typically fire bagasse with a moisture content of about 55% by weight. As much as 2.5 tons per day and 915 tons per year of DAF filter material could be generated. The amounts are not significant compared to the capacity of the existing boilers to fire a high-moisture solid fuel.

Requirements

1. Firing: The permittee may co-fire incidental amounts de-watered DAF filter material. To the extent practicable, the de-watered DAF filter material shall be commingled with bagasse in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C.]
2. Expansion: Prior to expanding the DAF system, the permittee shall notify the Permitting Authority and determine whether an air construction permit is required. [Rule 62-4.070, F.A.C.]
3. Used Oil Specifications: The de-watered DAF filter material may contain incidental amounts of used oil (lubrication oil or hydraulic fluids) generated on site at this facility. The permittee shall maintain records sufficient to document that the used oil meets the following requirements:
   a. The used oil shall not contain PCBs.
   b. The used oil shall meet the following EPA specifications for "on-specification used oil" in Subpart B of 40 CFR 279:

      Arsenic shall not exceed 5.0 ppm;
      Cadmium shall not exceed 2.0 ppm;
      Chromium shall not exceed 10.0 ppm;
      Lead shall not exceed 100.0 ppm;
      Total halogens shall not exceed 1000.0 ppm; and
      The flash point shall not be less than 100 degrees F.

   Used oil that does not meet the above requirements shall not be burned at this facility. [Rule 62-4.070, F.A.C.; Subpart B, 40 CFR 279]
4. Records: The permittee shall keep records sufficient to document compliance with the above requirements. The records shall be made available when requested by the Compliance Authority. [Rule 62-4.070, F.A.C.]

United States Sugar Corporation

111 Ponce de Leon Ave.
Clewiston, Florida 33440-1207
Telephone 863/902-2703
Fax 863/902-2729

Please take note of our change of address

October 5, 2004

Director of District Management
Florida Department of Environmental Protection
Post Office Box 2549
Fort Myers, Florida 33902-2549

RE: United States Sugar Corporation, Clewiston Mill Boiler No. 8
Hendry County, Florida
Project No. 0510003-024-AC Revised Draft Permit No. PSD-FL-333A

Gentlemen:

We are enclosing Affidavit of Publication certifying that the "Public Notice of Intent to Issue Air Permit" of reference was published in the legal section of the September 30, 2004 issue of THE *CLEWISTON NEWS*.

Please advise if there is anything further we need provide in this respect.

Sincerely,

UNITED STATES SUGAR CORPORATION

Donald Griffin
Specialty Sugar Manager

Enclosure

Cc: Michael Low
Peter Briggs
David Buff

The Clewiston News

Published Weekly Clewiston, Florida

AFFIDAVIT OF PUBLICATION

State of Florida

County of Hendry

Before the undersigned authority, personally appeared Tracy Whirls, who on oath says she is the Associate Editor of the Clewiston News, a weekly newspaper published at Clewiston in Hendry County, Florida, that the attached copy of advertisement being a Notice in the matter of US Sugar Corp - Notice of Intent ad# S21773 in the ______ court, was published in said newspaper in the issue(s) of September 30 2004.

Affiant further says that the said Clewiston News is a newspaper published at Clewiston, in said Hendry County, continuously published in said Hendry County, Florida, each week, and has been entered as periodicals matter at the post office in Clewiston, in said Hendry County, Florida, for a period of one year next preceding the first publication says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Tracy Whirls

Tracy Whirls

Sworn to and subscribed before me this 30th day of September 2004

Wanda W. Graham

Wanda W. Graham Notary Public

WANDA W. GRAHAM
MY COMMISSION # DD 200561
EXPIRES: May 5, 2007
Bonded Thru Notary Public Underwriters

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 0510003-024-AC, Revised Draft Permit No. PSD-FL-333A
United States Sugar Corporation, Clewiston Sugar Mill and Refinery
Hendry County, Florida

Applicant: The applicant for this project is the United States Sugar Corporation. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is the Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

Facility Location: The applicant proposes several changes to conditions in Air Permit No. PSD-FL-333, which authorizes the construction of Boiler 8. The new boiler is being constructed at U.S. Sugar Corporation's existing Clewiston sugar mill and refinery located in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposes several changes to the air construction permit for Boiler 8 to address initial operation during the shakedown period. Shakedown is a necessary part of the construction process in which the equipment is operated, evaluated, and adjusted to achieve the design specifications. The draft permit includes several related revisions. First, the shakedown period was clarified and deadlines for demonstrating compliance were specified. The draft permit now allows up to 2 hours of operation each month without the selective non-catalytic reduction system, which controls emissions of nitrogen oxides (NOx). this will allow the plant to gather uncontrolled NOx emissions data in order to adjust the control system. The original permit included an alternate NOx emissions standard that applied only during periods uncontrolled emissions (startup, shutdown, and malfunction). It is replaced with a requirement to simply report these uncontrolled NOx emissions.

The applicant also requested authorization to fire incidental amounts of dewatered filter material from the Dissolved Aeration Flotation (DAF) system, a part of the permitted wastewater treatment system. This material will be commingled with bagasse on the existing conveyor system and distributed among the operational boilers for firing. The described changes will not result in any significant emissions increases.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.) The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-3381. The South District's telephone number is 239/332-6975.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57 F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and required, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.
521773 CGS 9/30/04

Memorandum # Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief
Bureau of Air Regulation

THROUGH: Al Linero, Manager
Air Permitting South

FROM: Jeff Koerner, Air Permitting South

DATE: September 8, 2004

SUBJECT: Draft Air Permit No. PSD-FL-333A
Project No. 0510003-024-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project – Revision for Shakedown and DAF Filter Material

Attached for your review are the following items:

- Intent to Issue Revised Air Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft 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 November 20, 2004. I recommend your approval of the attached Draft Permit for this project.

Attachments

9-8-04

U.S. Sugar Corp.
Clewiston Mill

Al,

This is the revision to the PSD permit for new Boiler 8, which we discussed previously. It specifies "shakedown" requirements and allows up to 2 hours/month to operate w/o the SNCR system to gather "uncontrolled" NO_x emissions data. It also allows them to fire filter material from the WWT system which consists primarily of bagasse.

Thanks! Jeff

SENDER: *COMPLETE THIS SECTION*

- 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.

1. Article Addressed to:

Mr. William A. Raiola
Vice President of Sugar Processing
Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Rachel Felton ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Rachel Felton
C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2. Article Number (*Transfer from service label*) 7000 1670 0013 3110 3315

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 3315

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

Sent To
Mr. William A. Raiola, V.P. of Sugar Processing Operations
Street, Apt. No.; or PO Box No.
Clewiston Sugar Mill and Refinery
City, State, ZIP+4
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

PS Form 3800, May 2000 See Reverse for Instructions

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

Draft Air Permit No. PSD-FL-333A
Project No. 0510003-024-AC
Clewiston Sugar Mill and Refinery
Boiler 8 –Shakedown Revisions

PROJECT DESCRIPTION

The United States Sugar Corporation (U.S. Sugar) operates the existing Clewiston sugar mill and refinery in Hendry County, Florida. U.S. Sugar is currently constructing a new spreader stoker boiler (Boiler 8) that will purportedly be the largest bagasse-fired boiler in the United States. Based on the determination of "Best Available Control Technology", emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Boiler 8 is expected to be the first "bagasse-only" boiler to utilize an SNCR system. The final boiler design specified a maximum uncontrolled NOx emission rate of 0.30 lb/MMBtu, which is about 7% higher than the preliminary design. Based on the final designs of the boiler and controls, the permittee requests several specific changes related to shakedown, the SNCR system, and NOx emissions. It is proposed to revise the draft permit as follows.

- The shakedown period is clarified from "180 days" to "180 operational days", but not to exceed 360 days after first fire in the boiler. This will allow shakedown to include portions of two crop seasons, if necessary. Operation during shakedown in the off-season is limited to 60 days because the boiler is expected to have limited capacity at this time.
- Shakedown ends once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.
- The revised permit clarifies that the boiler may operate without the SNCR system during shakedown for restricted periods in order to gather necessary uncontrolled NOx emission rates across a range of operating parameters.
- After completing shakedown, the revised permit allows up to 2 hours of operation each month without the SNCR system. This will allow the plant to gather uncontrolled NOx emissions data and adjust the control of the SNCR system accordingly. This changes results in an insignificant amount of emissions.
- The original permit included an alternate NOx standard (0.28 lb/MMBtu) that applied only during periods of *uncontrolled emissions* (startup, shutdown, and malfunction). It is replaced with a requirement to simply report these periods of uncontrolled NOx emissions. The change is based on the final boiler design, which specifies a maximum uncontrolled NOx emission rate of 0.30 lb/MMBtu. It is also based on the realization that the alternate standard was really a placeholder for the expected maximum uncontrolled NOx emission rate.
- U.S. Sugar also supplemented the initial application with a request to fire de-watered filter material from the Dissolved Aeration Flotation (DAF) system. This consists of material washed from the sugar mill floor including bagasse, water, hydraulic fluid, and lubrication oil. Lime is added to the system as a coagulant. The used oils meet EPA's on-specification requirements. The DAF filter material is blended with bagasse on the conveyor system and fired in all of the boilers. At an estimated 2.5 tons per day, this incidental amount of material will result in an insignificant amount of emissions.

The changes do not trigger PSD applicability for any new pollutants.

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
Jeffery F. Koerner, P.E.
Registration Number: 49441

9-8-04
(Date)

Department of
Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

September 13, 2004

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-333A
Project No. 0510003-024-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Boiler 8 – Shakedown Revisions and DAF Filter Material

Dear Mr. Raiola:

On June 28, 2004, U.S. Sugar submitted an application to revise Air Permit No. PSD-FL-333 to primarily address details regarding the shakedown period associated with the SNCR system that will be installed on new Boiler 8. On August 23, 2004, U.S. Sugar substantially modified this application to include the firing of incidental amounts of de-watered DAF filter material. Boiler 8 is currently under construction at the Clewiston sugar mill, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, 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-333A
Project No. 0510003-024-AC
Clewiston Sugar Mill and Refinery
Boiler 8 – Shakedown Revisions
Hendry County, Florida

Facility Location: The applicant requests a revision of conditions in Air Permit No. PSD-FL-333, which authorizes construction of new Boiler 8. The new boiler is being constructed at U.S. Sugar Corporation's existing Clewiston sugar mill and refinery, which is located in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposes several changes to the air construction permit for Boiler 8 to address initial operation during the shakedown period. Shakedown is a necessary part of the construction process in which the equipment is operated, evaluated, and adjusted to achieve the design specifications. The draft permit includes several related revisions. First, the shakedown period was clarified and deadlines for demonstrating compliance were specified. The draft permit now allows up to 2 hours of operation each month without the selective non-catalytic reduction system, which controls emissions of nitrogen oxides (NOx). This will allow the plant to gather uncontrolled NOx emissions data in order to adjust the control system. The original permit included an alternate NOx emissions standard that applied only during periods uncontrolled emissions (startup, shutdown, and malfunction). It is replaced with a requirement to simply report these uncontrolled NOx emissions.

The applicant also requested authorization to fire incidental amounts of de-watered filter material from the Dissolved Aeration Flotation (DAF) system, a part of the permitted wastewater treatment system. This material consists of bagasse, water, lime and small amounts of lubrication oil and hydraulic fluid. The material will be commingled with bagasse on the existing conveyor system and distributed among the operational boilers for firing. The described changes will not result in any significant emissions increases. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-3381. The South District's telephone number is 239/332-6975.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet 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 Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of fourteen (14) days from the date of publication of the attached Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

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 "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the 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 9/13/04 to the persons listed below.

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 Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 9/13/04 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 0510003-024-AC, Revised Draft Permit No. PSD-FL-333A
United States Sugar Corporation, Clewiston Sugar Mill and Refinery
Hendry County, Florida

Applicant: The applicant for this project is the United States Sugar Corporation. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is the Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

Facility Location: The applicant proposes several changes to conditions in Air Permit No. PSD-FL-333, which authorizes the construction of Boiler 8. The new boiler is being constructed at U.S. Sugar Corporation's existing Clewiston sugar mill and refinery located in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposes several changes to the air construction permit for Boiler 8 to address initial operation during the shakedown period. Shakedown is a necessary part of the construction process in which the equipment is operated, evaluated, and adjusted to achieve the design specifications. The draft permit includes several related revisions. First, the shakedown period was clarified and deadlines for demonstrating compliance were specified. The draft permit now allows up to 2 hours of operation each month without the selective non-catalytic reduction system, which controls emissions of nitrogen oxides (NOx). This will allow the plant to gather uncontrolled NOx emissions data in order to adjust the control system. The original permit included an alternate NOx emissions standard that applied only during periods uncontrolled emissions (startup, shutdown, and malfunction). It is replaced with a requirement to simply report these uncontrolled NOx emissions.

The applicant also requested authorization to fire incidental amounts of de-watered filter material from the Dissolved Aeration Flotation (DAF) system, a part of the permitted wastewater treatment system. This material consists of bagasse, water, lime and small amounts of lubrication oil and hydraulic fluid. The material will be commingled with bagasse on the existing conveyor system and distributed among the operational boilers for firing. The described changes will not result in any significant emissions increases.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-3381. The South District's telephone number is 239/332-6975.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Project No. 0510003-024-AC
Air Permit No. PSD-FL-333A
Clewiston Sugar Mill and Refinery
ARMS Facility ID No. 0510003
Boiler 8 – Shakedown Revision

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 Resource Management
Bureau of Air Regulation
Air Permitting South Program
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

September 8, 2004

1. GENERAL PROJECT INFORMATION

Application Processing Schedule

05/03/04	Received some final design information and discussion of shakedown issue.
06/30/04	Received application requesting PSD Permit revisions regarding shakedown.
08/23/04	Received a modification of the previous application regarding the DAF filter material.
08/27/04	Received email from Golder Associates providing details of the DAF system.
08/30/04	Received second email from Golder Associates describing the DAF system; 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 existing boilers that fire bagasse and fuel oil. A sixth boiler (Boiler 8) is being constructed. Particulate matter emissions are controlled with wet scrubbers for Boilers 1 through 4 and with an electrostatic precipitator for Boilers 7 and 8. 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 existing facility is identified as a potential major source of hazardous air pollutants (HAP).

Title IV: The existing facility operates 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 facility as defined in Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63.

Project Description

In November of 2003, the Department issued Permit No. PSD-FL-333 to the U.S. Sugar Corporation (USSC), which authorized construction of Boiler 8 at the Clewiston Mill. The new boiler will likely be the largest sugar mill boiler in the United States with a maximum continuous heat input rate of 936 MMBtu per hour and steam generating rate of 500,000 pounds per hour. It was designed from the ground up specifically for the firing of bagasse to support the sugar mill and refinery operations of the existing plant.

The project consists of the following specific equipment: a balanced draft, membrane wall boiler (McBurney Corporation); a Magasiner technology twin spreader stoker (Gogeneration Systems Ltd); a supplemental distillate oil firing system (Peabody); non-saturating cyclone sand collectors (Thermal Energy Systems); an electrostatic precipitator (ESP) system (PPC Industries); and a selective non-catalytic reduction (SNCR) system (Fuel Tech). Pollutant emissions from the boiler will be controlled by the following equipment and techniques:

- CO and VOC emissions will be minimized by good combustion design and operating practices.
- NOx emissions will be reduced by a selective non-catalytic reduction (SNCR) system to inject urea.

- PM/PM_{10} emissions will be reduced by a wet cyclone sand separator followed by a dry ESP.
- SO_2 and sulfuric acid mist emissions will be minimized by the firing of low sulfur fuels including bagasse and distillate oil ($\leq$ 0.05% sulfur by weight).

The application was based on preliminary designs for the new equipment. The construction permit required submittal of the final designs within 90 days of making a final selection. As part of this application, USSC submitted the required final design specifications and satisfied the construction permit requirements. Due to the proposed NESHAP for industrial boilers (Subpart DDDDD), a strong emphasis in the final design of the boiler was placed on "complete combustion" to minimize CO emissions. This design resulted in higher furnace temperatures and possibly higher uncontrolled NOx emissions. The final boiler design specification indicated a maximum uncontrolled NOx emission rate of "0.30 lb/MMBtu" compared with the preliminary design rate of "0.28 lb/MMBtu" in the application. The uncontrolled NOx emission rate is critical in finalizing the design for the SNCR system and securing vendor guarantees.

As a result, USSC requests new conditions that specifically identify the shakedown period for the new boiler and control equipment. The purpose is to clarify the period of time needed to bring the new boiler and controls on line, establish uncontrolled NOx emission levels, tune the boiler and SNCR system, and work out any construction-related startup problems. Each request will be identified and discussed in the Section 3 of this technical evaluation.

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.). The new boiler remains subject to the applicable provisions in Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code.

Federal Regulations

NSPS: Boiler 8 remains subject to the applicable provisions of Subpart Db in 40 CFR 60, which is the New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Units.

NESHAP: Boiler 8 will be subject to the applicable provisions of Subpart DDDDD in 40 CFR 63, which are the National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters. Boiler 8 will be considered a new, large solid fuel fired boiler. NESHAP Subpart DDDDD became final at the end of February 2004, but has not yet been published in the Federal Register. The Department did not include the Subpart DDDDD requirements as part of this revised permit because changes have occurred for recently promulgated federal rules between "signed final" and "published final" versions. Therefore, Condition 26 was added to simply specify that Boiler 8 is subject to all applicable NESHAP Subpart DDDDD requirements.

Prevention of Significant Deterioration (PSD) Preconstruction Review

The existing Clewiston sugar mill and refinery is a PSD-major facility as defined in Rule 62-212.400, F.A.C. The original air construction permit project included the shutdown of existing Boiler 3 as well as the construction of new Boiler 8. Based on the resulting net emissions increases, the original project was subject to PSD preconstruction review for emissions of nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The Department determined the Best Available Control Technology requirements for each of these pollutants. Emissions of carbon monoxide (CO) netted out of PSD review with the shutdown of Boiler 3. The applicant's requests to revise permit conditions do not affect the Department's previous BACT determinations or trigger new PSD preconstruction review requirements.

3. PROJECT REVIEW – SHAKEDOWN REVISIONS

Request to Revise Condition 1 in Section 3A

Applicant's Request: This condition currently includes the requirement, that "... The permittee shall have a maximum of 180 days from first fire to perform the necessary shakedown for Boiler 8." USSC maintains that it intends to bring the new boiler and control equipment on line as quickly as possible. However, the new designs being used in this project (i.e., boiler, stoker, SNCR system, etc.) require a thorough and critical evaluation at startup. The new designs could present unique problems during the initial shakedown period. These construction-related problems must be worked through in order to fine tune and ready the systems for commercial operation.

In addition, it is expected that Boiler 8 will start up in mid-crop season (January), which could delay completion of the equipment shakedown. During the crop season (October through April), bagasse is readily available and demand for steam from the mill is high. However, during the off-season (May through September), demand for steam from the refinery is greatly reduced and it may be inefficient to run the new boiler for prolonged periods. Therefore, USSC requests that the "180 days" be clarified to mean "180 operating days". This would allow the shakedown period to include two different crop seasons if necessary.

Finally, it is important for USSC to identify the "as-built" flue gas temperatures and maximum uncontrolled NOx emission rates for a variety of operating conditions. These parameters are critical in determining the final physical placements of the urea injectors, the appropriate urea injection rates and configurations for the given conditions, and the final tuning of the automatic controls for the SNCR system. Urea will be injected at three different levels into the top of the boiler at the proper temperature range to ensure that the non-catalytic NOx reduction occurs. This makes it difficult to reliably monitor uncontrolled NOx emission rates unless the SNCR system is temporarily disabled. Therefore, USSC requests specific opportunities during shakedown to monitor uncontrolled NOx emissions without the SNCR system in operation.

Department's Response: The Department recognizes that Boiler 8 will likely be the largest sugar mill boiler in the United States and the application of SNCR technology is relatively new to this industry. Besides the New Hope Power cogeneration facility which fires wood chips as well as bagasse, it is perhaps the only other bagasse-fired boiler with an SNCR system. The Department agrees to clarify the shakedown period for this new project. The Department proposes to replace the sentence in Condition 1 regarding shakedown for Boiler 8 with, "Shakedown of the boiler is defined in Appendix H of this permit." Appendix H includes a discussion of shakedown and the following specific requirements:

1. Shakedown: Shakedown is limited to the first 360 calendar days after first fire in the boiler and shall not exceed 180 operational days after first fire in the boiler. An "operational day" is any day that Boiler 8 fires any fuel. During shakedown, Boiler 8 shall not operate more than 60 days during the off-season. For this plant, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. Shakedown is complete once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.
2. SNCR System: During the shakedown period, the permittee is authorized to operate the boiler without the SNCR system for purposes of commissioning the boiler and collecting uncontrolled NOx emissions data, provided:
    a. During the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed a total of 240 hours;
    b. After the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed 2 hours each day; and
    c. Notwithstanding the above periods, the operator shall fully utilize the SNCR system to the extent practicable and according to the manufacturer's recommended procedures.

3. CO and NOx CEMS: The CO and NOx CEMS shall be installed and certified within the first 45 operational days of shakedown. CEMS data collected on the first full day following completion of the shakedown period shall be used to begin demonstrating compliance with the CEMS-based emissions standards of the permit.
4. Initial Stack Tests: All initial stack tests required by this permit shall be conducted during the defined shakedown period, but no later than 60 days after achieving the maximum production rate, which is defined as a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average. The permittee shall provide written notification to the Permitting and Compliance Authorities within 10 days of achieving this maximum production rate.

The above requirements clarify the duration of shakedown, allow limited monitoring of uncontrolled NOx emissions, specify CEMS installation, identify the initial compliance demonstration for CEMS-based standards, and establish the deadline for conducting initial compliance stack tests. The Department also made the following related changes to the permit:

Section 3A, Condition 1: Added the following definition, "For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September." Although defined in the Title V permit, the term "crop season" is not otherwise defined in this PSD permit.

Section 3A, Condition 8: Added the following reference to new Appendix H, "{Permitting Note: Appendix H of this permit specifies additional requirements regarding the shakedown period and initial demonstration of compliance for the standards based on CEMS data.}

Request to Revise Condition 12 in Section 3A

Applicant's Request: This condition states that, "For the period of excluded data, NOx emissions shall not exceed 0.28 lb/MMBtu based on a block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction (alternative standard)." The basis for the alternate standard is the preliminary boiler design specification. As previously mentioned, the maximum uncontrolled NOx emissions rate is now expected to be higher based on the final boiler design. Emissions during startup, shutdown, and malfunction are difficult to control and should not be limited. Therefore, the applicant requests that this requirement be replaced with a permitting note that simply identifies the highest expected uncontrolled NOx emissions rate of 0.30 lb/MMBtu.

The applicant also requests authorization to operate the boiler without the SNCR system for 2 hours per month. This would allow the plant to collect uncontrolled NOx emissions data, which is then used to tune the SNCR system and adjust the control system accordingly. In addition, the applicant requested clarification of the "2 hours" of data exclusion to mean up to eight, 15-minute CEMS blocks (quadrants of an hour). This will provide flexibility in handling some of the short term upsets that can be caused by the mill operations.

Department's Response: The Department agrees that the alternate standard was specified as the maximum expected uncontrolled NOx emission rate (0.28 lb/MMBtu) based on the preliminary boiler design. For comparison purposes, the cogeneration boilers constructed in 1997 at the New Hope Power facility have actual uncontrolled NOx emissions ranging from approximately 0.22 to 0.25 lb/MMBtu. The CO emission standard for the cogeneration boilers is "0.50 lb/MMBtu based on a 30-day rolling average". These cogeneration boilers fire bagasse and wood chips and are about three quarters of the size of proposed Boiler 8. Due to the inverse relationship between CO and NOx for spreader stoker boilers, it is reasonable to expect that a boiler being designed to meet the new NESHAP requirements for CO emissions (~ 0.32 lb/MMBtu, 24-hour average) would have higher uncontrolled NOx emissions approaching 0.30 lb/MMBtu or higher.

The Department agrees that the alternate standard for startup and shutdown is actually a placeholder for the highest expected uncontrolled emission rate. As such, it does not really serve the original intended purpose, which was to ensure that emissions during these periods are minimized. Therefore, the Department agrees to the applicant's request. However, the Department will specify that all excluded emissions data be reported in the required Quarterly NOx and CO Emissions Report.

The Department also agrees to allow up to 2 hours of operation without the SNCR each month to collect uncontrolled NOx emissions data for purposes of adjusting the SNCR system. The maximum potential increase in emissions would be:

NOx Increase (TPY) = (0.30 lb/MMBtu - 0.14 lb/MMBtu) (936 MMBtu per hour) (24 hours per year) (ton/2000 lb)

1.8 tons per year of NOx

This amount is not significant when compared to the importance of identifying the uncontrolled NOx emissions rate and adjusting the SNCR system. It would not change PSD applicability for any pollutants. In addition, the Department agrees to clarify that up to eight, 15-minutes blocks of CEMS data may be excluded due to malfunctions. Condition 12 was revised accordingly and Condition 25 was revised to add the requirement to report these periods of uncontrolled emissions in the required Quarterly NOx and CO Emissions Report. Appendix G was revised to include this reporting.

4. PROJECT REVIEW – DAF FILTER MATERIAL

Request to Fire De-Watered DAF Filter Material

On August 23, 2004, U.S. Sugar modified their initial application to include authorization to fire material from the Dissolved Aeration Flotation (DAF) system in Boiler 8. As a maintenance practice, surface areas at the mill are periodically washed with water to remove debris. The wash water is collected in a series of drains and directed to the DAF filter to remove solids. Collected materials include bagasse, used oil, and lime. Bagasse results from spills at the sugar mill and boiler conveyor system. Small amounts of used oil consisting of hydraulic fluid and lubrication oil may be spilled or leaked to the floor from miscellaneous equipment throughout the sugar mill. A conservative estimate of use oil washed to the drains is 500 pounds per day. This used oil does not contain any polychlorinated byphenols (PCBs). Slaked lime is added to the DAF system to act as a coagulant in the clarification process. Drain water passes through the DAF filter and is discharged to the facility's permitted wastewater treatment system.

The applicant estimates that the DAF filter removes approximately 15,000 pounds of material per day, which consists of roughly 13,500 pounds of liquid per day and 1500 pounds of solids per day. The filter material is then pressed to remove approximately 10,000 pounds of liquids per day, which is directed to the permitted wastewater treatment system. The remaining "de-watered" DAF filter material now contains approximately 3000 pounds of water, 1500 pounds of solids (mostly bagasse), and 500 pounds of used oil (assuming all of the oil remains with the solids). Therefore, as much as 2.5 tons per day and 915 tons per year of DAF filter material could be generated.

The DAF filter material will be transferred to the bagasse conveyor system, which is capable of handling this material. It will be commingled with bagasse and distributed among the operational boilers. The filter material will burn like bagasse. The estimated daily rate of 2.5 tons per day represents much less than 1% of the nominal bagasse firing rate during the crop season. This incidental amount will have no impact on emissions.

Department Response

Disregarding the used oil, the de-watered DAF filter material would consist mostly of bagasse with a moisture content of about 65% by weight. A maximum of 2.5 tons per day of the DAF material would be blended with bagasse on the conveyor feed system and distributed to all of the boilers. For comparison purposes, Boiler 8 is capable of firing about 130 tons of bagasse per hour with a normal moisture content of about 55% by weight. The daily amount of de-watered DAF filter material comprises less than 2% of hourly feed rate for Boiler 8 alone or much less than a half percent of the daily feed rate for Boiler 8 alone. However, the DAF filter material would also be distributed among other boilers.

Boiler 8 is being constructed to fire bagasse with high moisture contents. The estimated maximum amounts of de-watered DAF filter material are incidental to the bagasse-firing capabilities of the boilers. Any used oil in the DAF filter material would qualify as "on-specification" used oil and would have some energy recovery benefits. The current Title V permit authorizes several of the boilers to fire "on-specification" used oil. In addition, the Title V permits also allows the firing of up to 500 cubic yards of soil contaminated with virgin petroleum products or "on-specification" used oil. The de-watered DAF filter material would tend to displace some of the normal bagasse feed when fired. However, even when evaluated alone, this amount of material will result in insignificant amounts of air emissions. The following table summarizes the maximum expected emissions from firing 915 tons of de-watered DAF material based on the highest emission factors for the boilers at this facility.

Pollutant	Factor lb/MMBtu	Heating Value MMBtu/ton	Heat Input MMBtu/year	Emissions TPY	PSD Significant Emission Rate TPY	PSD Review?
CO	6.5	7.2	6588	21.4	100	No
NOx	0.20	7.2	6588	0.7	40	No
PM/PM_{10}	0.30	7.2	6588	1.0	15/25	No
SO_2	0.06	7.2	6588	0.2	40	No
VOC	0.5	7.2	6588	1.6	40	No

Emissions impacts from new Boiler 8 would be even less. The Department concludes that the requested incidental amounts of de-watered DAF filter material may be fired in the sugar mill boilers, including Boiler 8. Condition 4 was revised to authorize the firing of this material. Appendix I was added to describe the material and add the following requirements: incidental amounts of de-watered filter material may be commingled with bagasse; notification if the DAF system is ever expanded; and proper documentation regarding the "on-specification" used oil.

5. PRELIMINARY DETERMINATION

Copies of the application were provided to the EPA Region 4 office, the National Park Service, and the Department's South District Office. EPA Region 4 responded that it had no comments. 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 revision. 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. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit changes. 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-333A 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-333A
Project No. 0510003-024-AC
Facility ID No. 0510003
SIC Nos. 2061, 2062
Permit Expires: July 1, 2007

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 PERMIT

Michael G. Cooke, Director
Division of Air Resource 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 (≤ 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 facility as defined in Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63.

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. Summary of Final BACT Determinations
Appendix F. Good Combustion and Operating Practices
Appendix G. Quarterly CO and NOx Emissions Report
Appendix H. Shakedown Period
Appendix I. De-Watered DAF Filter Material

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. Permit No. PSD-FL-333A revises original Permit No. PSD-FL-333 to specifically address the shakedown period for the boiler and SNCR system, authorized periods of uncontrolled NOx emissions, and the firing of de-watered DAF filter material.

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.]

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 no more 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 is 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 of nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO2), 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) of Subpart Db (industrial boilers) in 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C.; and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) of Subpart DDDDD (industrial boilers) in 40 CFR 63.} ~~See Appendices C and D of this permit for these applicable requirements.}~~

EQUIPMENT

1. Shutdown of Boiler 3: No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of first fire in Boiler 8. Shakedown of the boiler is defined in Appendix H of this permit. ~~The permittee shall have a maximum of 180 days from first fire to perform the necessary shakedown for Boiler 8.~~ During the authorized shakedown period:
   a. Boiler 8 may operate with the other existing boilers to ensure proper integration with the sugar mill and refinery. Any fuel oil fired in Boilers 1, 2, and 3 shall contain no more than 1.6% sulfur by weight.
   b. Boilers 3 and 8 may operate concurrently for no more than 90 individual days during which the combined steam production from Boilers 3 and 8 shall not exceed a daily average of 250,000 pounds per hour. After first fire and shakedown of Boiler 8, Boiler 3 shall be permanently shutdown prior to commencement of commercial operation of Boiler 8 or after completion of the crop season, whichever

occurs first. For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September.

No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of the permanent shutdown of Boiler 3 and of beginning commercial operation of Boiler 8. *{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. The authorized shakedown period provides a reasonable period to start up the newly designed Boiler 8, test operations, and make necessary adjustments. A limited amount of concurrent operation is allowed because Boiler 8 is replacing Boiler 3 and must be fully tested during the crop season.}* [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 design conditions of 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. Urea injection rates and zones will be determined based on parameters such as 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.

In addition, incidental amounts of de-watered DAF filter material may be commingled with bagasse and fired in Boiler 8 in accordance with the requirements in Appendix I of this permit. [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 x 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. The mass emission rates (pounds per hour) are based on the maximum 24-hour heat input rate. 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): To the extent practicable, short term emissions of carbon monoxide shall be controlled by implementing the good combustion and operating practices identified in Appendix F. *{Permitting Note: The Department intends to re-open this permit and include the 40 CFR 63 Subpart DDDDD requirements as appropriate.}* [Rules 62-4.070(3), 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 standard is an "initial demonstration standard" intended to show the capabilities of the SNCR system as designed. After the initial compliance test, subsequent compliance shall be demonstrated with the long-term CEMS-based standard specified in Condition 8b.}* [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 0.38 lb/MMBtu during any consecutive 12 months excluding periods of startup, shutdown, and malfunction. As determined by CEMS data, CO emissions shall not exceed 1285 tons during any consecutive 12 months including periods of startup, shutdown, and malfunction. *{Permitting Note: Compliance with the annual mass emission 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 (NO_x): As determined by CEMS data, NO_x emissions shall not exceed 0.14 lb/MMBtu based on a 30-day rolling average. [Rule 62-212.400(5)(c), F.A.C.]

   {Permitting Note: Appendix H of this permit specifies additional requirements regarding the initial shakedown period and initial demonstration of compliance for the CEMS-based standards.}

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. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [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*: Provided best operational practices are used to minimize emissions, CO CEMS data collected during startups, shutdowns, and malfunctions may be excluded from the determination of compliance with the CO standard based on heat input rate (lb/MMBtu, 12-month rolling average). However, all valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total).

   b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, ~~and~~ malfunction, and authorized periods of uncontrolled NOx monitoring 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 (eight 15-minute CEMS blocks or quadrants of an hour). ~~and t~~The permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

      4) For two hours each month, the permittee may operate the boiler without the SNCR system in order to collect uncontrolled NOx emissions data with the CEMS. For purposes of collecting uncontrolled NOx emissions data to adjust the SNCR system, excluded data shall not exceed two, 1-hour values during any calendar month. *{Permitting Note: Based on the final design specifications, uncontrolled NOx emissions are expected to be 0.30 lb/MMBtu. Uncontrolled NOx data collected during these periods will be used to adjust the SNCR system as necessary.}*

      ~~4) For the period of excluded data, NOx emissions shall not exceed 0.28 lb/MMBtu 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. This alternate opacity standard does not impose a separate annual testing requirement.

   CO and NOx CEMS data excluded due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring shall be summarized and reported in the "Quarterly CO and NOx Emissions Report" required by this permit. {Permitting Note: ~~Alternate emissions standards were specified~~ Allowances for these periods are provided for carbon monoxide and nitrogen oxides because compliance is continuously demonstrated by CEMS data. Similarly, an alternate standard is identified for opacity during startup and shutdown because compliance is readily observable. As sulfur dioxide emissions are a function of the fuel sulfur, it is not expected that startups or shutdowns would cause excess emissions of this pollutant. It is possible that emissions of particulate matter and volatile organic compounds could exceed the permit standards in terms of "lb/MMBtu" during startups and shutdowns. However, the Department has good reason to believe that the mass emission rates of these pollutants (lb/hour) will not exceed the specified standards due to reduced loads and fuel firing rates. In any case, the specified test methods are generally applicable only during steady-state operation. Therefore, no alternate emissions standards are specified and compliance shall determined by the test methods and procedures specified in this permit.}

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 boiler steam conditions and production rate shall be monitored and recorded during the test. The bagasse fuel firing rate (tons per hour) shall be calculated and recorded based on the steam parameters. 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: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency of 62%. Results of the test shall be submitted to the Department within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. [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, 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 ammonia slip, PM, SO_2, VOC, and opacity shall also be conducted during each federal fiscal year (October 1st to September 30th). 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 tests for NOx and VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for NOx emissions may be used to demonstrate compliance with the initial stack test standards for this pollutant. 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 "lb/MMBtu".

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 "lb/MMBtu" 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 "lb/MMBtu".

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. <u>Alternate Opacity Monitoring Plan</u>: Based on written approval from EPA Region 4, the permittee shall 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 in accordance with the provisions of NSPS Subparts A and Db to demonstrate compliance with the opacity standards of the permit.

{Permitting Note: In a letter dated September 22, 2003, EPA Region 4 approved the above Alternate Opacity Monitoring Plan.} [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

20. <u>ESP Monitoring Plan</u>: 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, 3-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 and 3-hour block averages beginning at the top of each hour, excluding monitoring

malfunctions, associated repairs, and required QA/QC activities.

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.]

21. SNCR Urea Injection: 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.]

22. Wet Cyclone: 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

23. Stack Test Reports: 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), calculated bagasse firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

24. Monthly Operations Summary: 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.]

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled NOx emissions monitoring and CEMS systems monitor availability for the previous quarter. If CO or NOx CEMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. 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.]

FEDERAL REQUIREMENTS

26. NSPS Subpart Db: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix D of this permit summarizes these requirements.

27. NESHAP Subpart DDDDD: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63 for "Industrial/Commercial/Institutional Boilers and Process Heaters". *{Permitting Note: The final rule for Subpart DDDDD was not yet published in the Federal Register at the issuance of this permit.}*

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.

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 (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).

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.

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.

<u>§60.42b Standard for Sulfur Dioxide</u>

(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.}

<u>§60.43b Standard for Particulate Matter</u>

(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. *{Not applicable; see "Permitting Note" at end of section.}*

(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)

{Not applicable; see "Permitting Note" at end of section.}

(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. *{Not applicable; see "Permitting Note" at end of section.}*

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis. *{Not applicable; see "Permitting Note" at end of section.}*

{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 distillate oil during startup or as a supplemental fuel. 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 (≤ 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, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil.}*

§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. *{Not applicable; see "Permitting Note" at end of section.}*

(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 continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing 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. The permit also restricts the firing of distillate oil to an annual capacity factor of no more than 10%.}

Summary of Final BACT Determinations

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]	Good Combustion Practices	0.38 lb/MMBtu, 12-month rolling average 1285 tons per consecutive 12 months, (rolling total)
NOx	0.14 lb/MMBtu {Initial demonstration standard; subsequent compliance based on CEMS.}	0.14 lb/MMBtu, 30-day rolling average ~~0.28 lb/MMBtu , average during startup, shutdown, or malfunction period~~
PM	0.026 lb/MMBtu	Not Applicable
SO_2 (Surrogate for SAM)	0.06 lb/MMBtu	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	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: NOx (EPA Method 7E); PM (EPA Method 5); SO_2 (EPA Method 6C); VOC (EPA Methods 18 and

25A, as propane); and opacity (EPA Method 9). 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, or authorized periods of uncontrolled NOx monitoring. ~~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, EPA Region 4 approved (September 22, 2003) an alternate sampling procedure that includes additional EPA Method 9 observations when firing distillate oil. In addition, the draft permit requires monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP.

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 the commercial operation of 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 the original project.

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/PM_{10} – 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: _____ e. Total _____
   b. Shutdowns: _____ d. Uncontrolled NOx Monitoring: _____
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**

Shakedown Period

Boiler 8 will be a new type of spreader-stoker specifically designed for the efficient combustion of bagasse. Bagasse is the fibrous byproduct remaining from sugarcane after the milling process. The sugarcane milling season runs from October through April. The proposed startup date for the new boiler is January of 2005, which is approximately halfway through the sugarcane milling season. It is expected that a short, initial shakedown period will be necessary for the boiler prior to shakedown of the SNCR system. Although the facility also includes a refinery that operates during the milling off-season, Boiler 8 is not expected to operate much during the off season unless refinery steam demands are high enough to take advantage of large steam production rate from this unit. For these reasons, the Department authorizes the following shakedown period in accordance with the specific conditions, which are in addition to those specified in Section 3 of the permit.

1. Shakedown: Shakedown is limited to the first 360 calendar days after first fire in the boiler and shall not exceed 180 operational days after first fire in the boiler. An "operational day" is any day that Boiler 8 fires any fuel. During shakedown, Boiler 8 shall not operate more than 60 days during the off-season. For this plant, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. Shakedown is complete once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.
2. SNCR System: During the shakedown period, the permittee is authorized to operate the boiler without the SNCR system for purposes of commissioning the boiler and collecting uncontrolled NOx emissions data, provided:
   a. During the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed a total of 240 hours;
   b. After the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed 2 hours each day; and
   c. Notwithstanding the above periods, the operator shall fully utilize the SNCR system to the extent practicable and according to the manufacturer's recommended procedures.
3. CO and NOx CEMS: The CO and NOx CEMS shall be installed and certified within the first 45 operational days of shakedown. CEMS data collected on the first full day following completion of the shakedown period shall be used to begin demonstrating compliance with the CEMS-based emissions standards of the permit.
4. Initial Stack Tests: All initial stack tests required by this permit shall be conducted during the defined shakedown period, but no later than 60 days after achieving the maximum production rate, which is defined as a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average. The permittee shall provide written notification to the Permitting and Compliance Authorities within 10 days of achieving this maximum production rate.

{Permitting Note: After demonstrating compliance and commencing commercial operation, the conditions of Appendix H will become obsolete and need not be included in the Title V air operation permit. The above requirements do not supersede any federal requirements regarding shakedowns for purposes of complying with NSPS or NESHAP regulations. Boiler 8 has a maximum heat input rate greater than 100 MMBtu/hour and is permitted to fire bagasse as the primary fuel with distillate oil as a startup and supplemental fuel. As such, it is an "affected facility" as defined in NSPS Subpart Db of 40 CFR 60. This NSPS regulates emissions of sulfur dioxide, particulate matter, opacity, and nitrogen oxides for the firing of coal, oil, or natural gas (or mixtures of these fuels with other fuels). However, the NSPS standards for particulate matter and sulfur dioxide are not applicable because the new boiler does not employ add-on controls to reduce sulfur dioxide emissions. Instead, sulfur dioxide emissions are limited by the firing of very low sulfur distillate oil and bagasse. In turn, the nitrogen oxide emission standard does not apply because the annual capacity factor for the very low sulfur distillate oil is less than 10% as conditioned by the permit. Only opacity is regulated by NSPS Subpart Db for this new boiler when firing distillate oil. Boiler 8 is also subject to the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.}

De-Watered DAF Filter Material

Description

As a maintenance practice, surface areas at the mill are periodically washed with water to remove debris. The wash water is collected in a series of drains and directed to the Dissolved Aeration Flotation (DAF) system to remove solids. Collected materials include bagasse, used oil, and lime. Bagasse results from spills at the sugar mill and boiler conveyor system. Small amounts of used oil consisting of hydraulic fluid and lubrication oil may be spilled or leaked to the floor from miscellaneous equipment throughout the sugar mill. A conservative estimate of use oil washed to the drains is 500 pounds per day. This used oil does not contain any polychlorinated byphenols (PCBs). Slaked lime is added to the DAF system to act as a coagulant in the clarification process. Drain water passes through the DAF filter and is discharged to the facility's permitted wastewater treatment system.

The DAF filter removes approximately 15,000 pounds of material per day, which consists of roughly 13,500 pounds of liquid per day and 1500 pounds of solids per day. The filter material is then pressed to remove approximately 10,000 pounds of liquids per day, which is also transferred to the permitted wastewater treatment system. The remaining "de-watered" DAF filter material now contains approximately 3000 pounds of water, 1500 pounds of solids (mostly bagasse), and 500 pounds of used oil (assuming all of the oil remains with the solids). Disregarding the used oil, the de-watered DAF filter material would consist mostly of bagasse with a moisture content of about 65% by weight. The sugar mill boiler typically fire bagasse with a moisture content of about 55% by weight. As much as 2.5 tons per day and 915 tons per year of DAF filter material could be generated. The amounts are not significant compared to the capacity of the existing boilers to fire a high-moisture solid fuel.

Requirements

1. Firing: The permittee may co-fire incidental amounts de-watered DAF filter material. To the extent practicable, the de-watered DAF filter material shall be commingled with bagasse in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C.]

2. Expansion: Prior to expanding the DAF system, the permittee shall notify the Permitting Authority and determine whether an air construction permit is required. [Rule 62-4.070, F.A.C.]

3. Used Oil Specifications: The de-watered DAF filter material may contain incidental amounts of used oil (lubrication oil or hydraulic fluids) generated on site at this facility. The permittee shall maintain records sufficient to document that the used oil meets the following requirements:

   a. The used oil shall not contain PCBs.

   b. The sulfur content of the used oil shall not exceed 0.05% sulfur by weight.

   c. The used oil shall meet the following EPA specifications for "on-specification used oil" in Subpart B of 40 CFR 279:

      Arsenic shall not exceed 5.0 ppm;
      Cadmium shall not exceed 2.0 ppm;
      Chromium shall not exceed 10.0 ppm;
      Lead shall not exceed 100.0 ppm;
      Total halogens shall not exceed 1000.0 ppm; and
      The flash point shall not be less than 100 degrees F.

   Used oil that does not meet the above requirements shall not be burned at this facility. [Rule 62-4.070, F.A.C.; Subpart B, 40 CFR 279]

4. Records: The permittee shall keep records sufficient to document compliance with the above requirements. The records shall be made available when requested by the Compliance Authority. [Rule 62-4.070, F.A.C.]

United States Sugar Corporation

111 Ponce de Leon Ave.
Clewiston, Florida 33440-1207
Telephone 863/902-2703
Fax 863/902-2729

RECEIVED
AUG 23 2004
BUREAU OF AIR REGULATION

August 19, 2004

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, Fl. 32399-2400

Attention: Mr. Jeffery Koerner, P.E.

RE: United States Sugar Corporation (U.S. Sugar) – Clewiston Mill
Proposed New Boiler No. 8
DEP Project No. 0510003-021-AC (PSD-FL-333)
Application for Used Oil Burning
0510003-024-AC

Dear Mr. Koerner:

Enclosed in duplicate is an Application for Used Oil Burning in Boiler No. 8 at the Clewiston Mill.

Please advise if there is anything further we need provide in this regard.

Sincerely,

UNITED STATES SUGAR CORPORTION

Donald Griffin
Manager, Sepecialty Sugar

DG:jt

Enclosures: 2

cc: W. A. Raiola
Michael Low
Peter Briggs
Ron Blackburn, DEP

RECEIVED
AUG 23 2004
BUREAU OF AIR REGULATION

APPLICATION FOR
USED OIL BURNING
IN BOILER NO. 8
U.S. SUGAR CORPORATION
CLEWISTON MILL

Prepared For:
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

August 2004
0437570

DISTRIBUTION:
4 Copies – FDEP
2 Copies – U.S. Sugar Corporation
1 Copy – Golder Associates Inc.

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: United States Sugar Corporation	
2. Site Name: U.S. Sugar Clewiston Mill	
3. Facility Identification Number: 0510003	
4. Facility Location...: Street Address or Other Locator: W.C. Owens Ave. and S.R. 832 City: Clewiston County: Hendry Zip Code: 33440	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: William A. Raiola, Senior Vice President, Sugar Processing Operations
2. Application Contact Mailing Address... Organization/Firm: United States Sugar Corporation Street Address: 111 Ponce DeLeon Ave. City: Clewiston State: Florida Zip Code: 33440
3. Application Contact Telephone Numbers... Telephone: (863) 983-8121 ext. Fax: (863) 902-2729
4. Application Contact Email Address: wraiola@ussugar.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	8-23-04
2. Project Number(s):	0510003-024-AC
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Air Construction Permit application to fire facility-generated on-specification used oil in Boiler No. 8.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
028	Boiler No. 8	AC1A	n/a

Application Processing Fee

Check one: ☐ Attached - Amount: $__________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **William A. Raiola, Senior Vice President, Sugar Processing Operations**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce DeLeon Ave.** City: **Clewiston** State: **FL** Zip Code: **33440**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**
4.	Owner/Authorized Representative Email Address: **wraiola@ussugar.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Signature Date 8/18/08

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff 8/9/04

Signature Date

(seal)

* Attach any exception to certification statement.

** Board of Professional Engineers Certificate of Authorization #00001670

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 506.1 North (km) 2956.9		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 26/44/06 Longitude (DD/MM/SS) 80/56/19	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 20	6. Facility SIC(s): 2061, 2062
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Wiliam A. Raiola, Senior Vice President, Sugar Processing Operations
2. Facility Contact Mailing Address... Organization/Firm: United States Sugar Corporation Street Address: 111 Ponce DeLeon Ave. City: Clewiston State: FL Zip Code: 33440
3. Facility Contact Telephone Numbers: Telephone: (863) 983-8121 ext. Fax: (863) 902-2729
4. Facility Contact Email Address: wraiola@ussugar.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total - PM	A	No
Sulfur Dioxide - SO_2	A	No
Nitrogen Oxides - NO_x	A	No
Carbon Monoxide - CO	A	No
Particulate Matter - PM_{10}	A	No
Sulfuric Acid Mist - SAM	A	No
Total Hazardous Air Pollutants - HAPs	A	No
Volatile Organic Compounds - VOC	A	No
Acetaldehyde - H001	A	No
Benzene - H017	A	No
Formaldehyde - H095	A	No
Phenol - H144	A	No
Polycyclic Organic Matter - H151	A	No
Styrene - H163	A	No
Toluene - H169	A	No
Naphthalene - H132	A	No
Dibenzofuran - H058	A	No

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID Nos. Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:____ ☒ Previously Submitted, Date:3/2003	
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:____ ☒ Previously Submitted, Date:3/2003	
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____	

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:_______ ☒ Not Applicable (existing permitted facility)	
2. Description of Proposed Construction or Modification: ☒ Attached, Document ID:Part B	
3. Rule Applicability Analysis: ☒ Attached, Document ID:Part B	
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable	
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable	
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable	
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable	
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable	
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable	

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Boiler No. 8

3. Emissions Unit Identification Number: **028**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**20**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Membrane wall, balanced-draft stoker boiler fired by carbonaceous fuel and distillate fuel oil (Grade No. 2) with a maximum sulfur content of 0.05% by weight. Fuel oil can include facility-generated on-specification used oil.

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **550,000 lb/hr steam**	
3. Maximum Heat Input Rate: **1,030** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rate based on 1-hour maximum steam rate of 555,000 lb/hr for carbonaceous fuel firing. The maximum permitted 24-hour average heat input rate for firing carbonaceous fuel is 936 MMBtu/hr and the maximum permitted 1-hour average heat input rate for firing No. 2 fuel oil is 562 MMBtu/hr (Permit No. 0510003-021-AC/PSD-FL-333). The permitted annual steam production limit is $3.6135x10^9$ lb of steam per consecutive 12-month period.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; All boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **143.06**	5. Maximum Annual Rate: **939,875**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on a maximum heat input rate of 1,030 MMBtu/hr (1-hr max) and the annual rate is based on a 75% capacity factor.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; Distillate Oil; Grades 1 and 2**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **4.161**	5. Maximum Annual Rate: **6,073.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Maximum hourly and annual rates and the maximum sulfur content of the distillate fuel oil based on current permit limits (Permit No. 0510003-021-AC/PSD-FL-333). Includes combustion of facility-generated on-specification used oil.**		

PART B

SUPPLEMENTAL INFORMATION FOR CONSTRUCTION PERMIT APPLICATION

PART B

SUPPLEMENTAL INFORMATION FOR CONSTRUCTION PERMIT APPLICATION

United States Sugar Corporation (U.S. Sugar) owns and operates a sugar mill and refinery located in Clewiston, Hendry County, Florida. The mill and refinery currently operate under Title V operating permit No. 0510003-014-AV. U.S. Sugar harvests sugar cane and transports it to the Clewiston Mill, where the cane is processed into raw sugar in the mill. U.S. Sugar sells some of the raw sugar, but the majority of the raw sugar is refined into white sugar.

U.S. Sugar operates five sugar mill boilers at the Clewiston Mill. The five boilers provide steam to the sugar mill as well as to the sugar refinery. Boiler Nos. 1, 2, 3, and 4 operate primarily during the crop season, which is typically October through June, to provide steam to the sugar mill. Boiler No. 7 operates year-around to provide steam to the sugar mill during the crop season and steam to the sugar refinery during the off-season. Boiler No. 7 is the primary boiler used to meet the steam demands of the refinery during the off-crop season. Boiler Nos. 1 through 4 can operate as backup units during the off-season when Boiler No. 7 is down for maintenance, repair, or during periods of unusually low steam demand.

U.S. Sugar has obtained an Air Construction Permit for Boiler No. 8 and is in the process of constructing the boiler. Boiler No. 8 is currently permitted to fire bagasse and very low sulfur distillate fuel oil (0.05% or less by weight). Once Boiler No. 8 is fully operational, and after a 180-day shakedown period, Boiler No. 3 will be permanently retired.

Boiler Nos. 1, 2, and 3 are each permitted to fire bagasse, No. 6 fuel oil, and on-specification (on-spec) used oil generated on site. Upon retirement of Boiler No. 3, U.S. Sugar will lose part of their capacity to manage on-spec used oil generated onsite. To remedy this situation, U.S. Sugar submitted an Air Construction Permit Application for Boiler Nos. 4 and 7 to allow firing of on-spec used oil, generated onsite, in these boilers. This application was submitted to the Department's South District office. Since Boiler No. 8 is currently under a construction permit issued by the Department's Tallahassee office, an application to revise the Boiler No. 8 permit to burn used oil must be submitted to Tallahassee. As such, U.S. Sugar is submitting this Air Construction Permit Application to fire on-spec used oil in Boiler No. 8.

Title 40 of the Code of Federal Regulations (CFR), Part 279.1, Subpart B – Applicability, states that "material containing or otherwise contaminated with used oil that are burned for energy recovery are subject to regulation as used oil under this part." U.S. Sugar has historically fired material in Boiler No. 3 that meets the definition of used oil. This material consists of primarily a mixture of bagasse and lime, but is also typically contaminated with on-spec used oil as defined by 40 CFR 279. Approximately 2,000 gallons of this material is generated and burned daily during the crop season. U.S. Sugar requests authorization to also burn this on-spec used oil in Boiler No 8.

Permit No. 0510003-021-AC/PSD-FL-233 allows Boiler No. 8, after becoming operational, to burn bagasse and new No. 2 distillate oil containing no more than 0.05% sulfur by weight. The total maximum heat input rate from the oil burners is 562 MMBtu/hr (4,161 gallons per hour). The total maximum heat input to the boiler from all fuels is 1,030 MMBtu/hr as a maximum 1-hour average, and 936 MMBtu/hr as a maximum 24-hour average. U.S. Sugar is not requesting to increase the currently permitted emissions rates, heat input rates, or steam production rates for Boiler No. 8 by this application.

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

June 21, 2004

0237619

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Attention: Mr. Jeffery Koerner, P. E.

RE: United States Sugar Corporation (U.S. Sugar) – Clewiston Mill
Proposed New Boiler No. 8
DEP Project No. 0510003-021-AC (PSD-FL-333)
Additional Information Response #3

Dear Mr. Koerner

In response to your letter dated May 25, 2004, please find attached revised application form pages for Boiler No. 8. The purpose of this update is to support United States Sugar Corporation's (U.S. Sugar) request to revise the current PSD air permit to clarify the shakedown period and to remove the reference to uncontrolled NO_x emissions. Also included are the vendor design data for the wet sand cyclone. The revisions to the application form reflect the final issued PSD permit, as well as the vendor data for the control equipment. The new MACT standards for industrial boilers (40 CFR 63. Subpart DDDD) are not reflected in the form, since these have not yet been published in the Federal Register and could change prior to the compliance date of 2007.

The attached form and data supplement the information previously submitted to the Department on May 3, 2004. Thank you for review of this information. Please call or email me if you have any questions concerning this information.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

David T. Larocca
Staff Engineer

DB/DTL/jej

Enclosures

cc: Don Griffin
Peter Briggs
Ron Blackburn, DEP

Y:\Projects\2002\0237619 US Sugar\4\4.1\L062104-7619.doc

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

June 30, 2004

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: United States Sugar Corporation – Clewiston Mill
Boiler No. 8 revision
0510003-021-AC, PSD-FL-333A

Dear Mr. Worley:

Enclosed for your review and comment is a request to modify a PSD permit issued to U.S. Sugar at their Clewiston Mill in Hendry County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Jeff Koerner, review engineer, at 850/921-9536.

Sincerely,

Patty Adams

for A.A. Linero, P.E.
Administrator
South Permitting Section

AAL/pa

Enclosure

cc: J. Koerner

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 25, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. David Buff, P.E.
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500

Re: U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
New Boiler 8 Project, Air Permit No. PSD-FL-333
Boiler and Air Pollution Control Design Information

Dear Mr. Buff:

Air Permit No. PSD-FL-333 authorizes the construction of new bagasse-fired Boiler 8 at the Clewiston sugar mill and refinery. In Section 3A of this permit, Conditions 2 and 3 require the submittal of the "final primary design details" for the proposed boiler and air pollution control equipment. On May 3, 2004, the Department received your submittal of the final design details for the boiler, electrostatic precipitator, and selective catalytic reduction system (received), which fulfills the requirement to submit this information for these systems. You have stated that design details for the wet sand cyclone will be submitted after the vendor is selected.

The submittal also includes a request to revise the current PSD air permit to clarify the shakedown period and remove the reference to uncontrolled NOx emissions. These items will require a modification of the PSD permit and an appropriate public notice. In addition to the information you have already provided, please submit your request on the Department's air permit application form. For such a permit modification, this would consist of at least the first 6 pages plus any other pages that would require a change as a result of your request. Upon receipt of the application, the Department will begin the review and processing your request. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

Jeffery J. Koerner

Jeff Koerner, Air Permitting South
DARM - Bureau of Air Regulation

cc: Mr. Peter Briggs, USSC
Mr. Don Griffin, USSC
Mr. Ron Blackburn, SD Office

SENDER: *COMPLETE THIS SECTION*

- 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.

1. Article Addressed to:

Mr. David Buff, P.E.
Golder Associates, Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Mary H Reinert ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Mary H Reinert

C. Date of Delivery 5-27-04

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Transfer from service label)* 7001 1140 0002 1578 1284

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

Mr. David Buff, P.E.

7001 1140 0002 1578 1284

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

Postmark Here

Sent To Mr. David Buff, P.E.

Street, Apt. No.; or PO Box No. 6241 NW 23rd Street, Suite 500

City, State, ZIP+4 Gainesville, Florida 32653-1500

PS Form 3800, January 2001 See Reverse for Instructions

AIR PERMIT APPLICATION
BOILER NO. 8
U.S. SUGAR CORPORATION
CLEWISTON, FLORIDA

Prepared For:
United States Sugar Corporation
111 Ponce DeLeon Ave.
Clewiston, Florida 33440

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

June 2004
0237619

DISTRIBUTION:
4 Copies – FDEP
2 Copies – U.S. Sugar
2 Copies – Golder Associates Inc.

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **United States Sugar Corporation**
2. Site Name: **U.S. Sugar Clewiston Mill**
3. Facility Identification Number: **0510003**
4. Facility Location...:
   Street Address or Other Locator: **W.C. Owens Ave. and S.R. 832**
   City: **Clewiston** County: **Hendry** Zip Code: **33440**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **William A. Raiola, Senior Vice President, Sugar Processing Operations**
2. Application Contact Mailing Address...
   Organization/Firm: **United States Sugar Corporation**
   Street Address: **111 Ponce Deleon Ave.**
   City: **Clewiston** State: **FL** Zip Code: **33440**
3. Application Contact Telephone Numbers...
   Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**
4. Application Contact Email Address: **wraiola@ussugar**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	6-28-04
2. Project Number(s):	0510003-024-AC
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

FACILITY INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Update the construction details for new Boiler No. 8, and to revise the PSD permit to clarify the shakedown period for the boiler.

FACILITY INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
028	Boiler No. 8		

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ Not Applicable

FACILITY INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name : **William A. Raiola, Senior Vice President, Sugar Processing Operations**	
2. Owner/Authorized Representative Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce Deleon Ave.** City: **Clewistion** State: **FL** Zip Code: **33440**	
3. Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**	
4. Owner/Authorized Representative Email Address: **wraiola@ussugar.com**	
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* [signature] June 24, 2004 Signature Date	

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   ____________________ ________________
   Signature Date

FACILITY INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff　　　　6/22/04

Signature　　　　Date

(seal)

DAVID A. BUFF ... CERTIFICATE ... STATE OF FLORIDA ... PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

**** Board of Professional Engineers Certificate of Authorization #00001670**

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
   - ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   - ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)
   - ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
   - ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
   - ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.
2. Description of Emissions Unit Addressed in this Section: **Boiler No. 8**
3. Emissions Unit Identification Number: **028**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**20**	☐ Yes ☐ No

9. Package Unit:
   Manufacturer: Model Number:
10. Generator Nameplate Rating: MW
11. Emissions Unit Comment:
   Stoker boiler fired by carbonaceous fuel, and low sulfur No. 2 fuel oil.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator** **Wet Sand Separator** **Selective Non-Catalytic Reduction System (SNCR)**	
2. Control Device or Method Code(s): **010, 099, 107**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **550,000 lb/hr steam**	
3. Maximum Heat Input Rate: **1,030** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24**hours/day **52**weeks/year	 **7**days/week **8,760**hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on 1-hour maximum steam rate (above) for carbonaceous fuel firing. Maximum 24-hour average firing for carbonaceous fuel is 936 MMBtu/hr. Proposed maximum for No. 2 fuel oil is 562 MMBtu/hr**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-8**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **13.0** feet
8. Exit Temperature: **335**°F	9. Actual Volumetric Flow Rate: **425,400** acfm	10. Water Vapor: **24**%
11. Maximum Dry Standard Flow Rate: **225,000** dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on biomass firing at maximum 24-hour heat input rate. Maximum Dry Standard Flow Rate is at 7-percent oxygen.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; All boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **143.06**	5. Maximum Annual Rate: **939,875**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.1 (dry)**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on 1,030 MMBtu/hr (1-hr max) and maximum annual rate based on 75-percent capacity factor or 6,767,100 MMBtu/yr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Distillate Oil; Grades 1 and 2**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1000 Gallons**	
4. Maximum Hourly Rate: **4.161**	5. Maximum Annual Rate: **6,073.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Rates based on proposed 562 MMBtu/hr and a maximum of 6,073,600 gallons of fuel oil per year.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	099	010	EL
PM10	099	010	EL
SO2			EL
NOX	107		EL
CO			EL
VOC			EL
SAM			NS
PB	099	010	EL
H021	099	010	EL
H114			EL
H017			EL
H095			EL
HAPS			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.8**lb/hour **88.0**tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.026 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.026 lb/MMBtu = 26.8 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.026 lb/MMBtu ÷ 2,000 lb/ton = 88.0 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-021-AC/PSD-FL-333.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.026 lb/MMBtu**	4. Equivalent Allowable Emissions: **26.8**lb/hour **88.0**tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.8**lb/hour **88.0**tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.026 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.026 lb/MMBtu = 26.8 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.026 lb/MMBtu ÷ 2,000 lb/ton = 88.0 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-021-AC/PSD-FL-333.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.026 lb/MMBtu**	4. Equivalent Allowable Emissions: **26.8**lb/hour **88.0**tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **175.1** lb/hour **203.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.17 lb/MMBtu (1-hour)** Reference: **Similar Boilers**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.17 lb/MMBtu = 175.1 lb/hr** **3-hour and Annual: 6,767,100 MMBtu/yr x 0.06 lb/MMBtu ÷ 2,000 lb/ton = 203.0 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. 3-hr and Annual based on Permit No. 0510003-021- AC/PSD-FL-333.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **56.2**lb/hour **203.0**tons/year
5. Method of Compliance: **EPA Method 6c**	
6. Allowable Emissions Comment (Description of Operating Method): **24-hour and annual limit is 0.06 lb/MMBtu. Emissions representative of bagasse firing only.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lbMMBtu**	4. Equivalent Allowable Emissions: **28.1**lb/hour **20.5**tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions representative of No. 2 fuel oil firing with 0.05 % S. Annual emissions based on proposed limit of 6,073,600 gal/yr.**	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **309.0** lb/hour **744.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.30 lb/MMBtu** Reference: **Permit No. 0510003-14-AV**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.030 lb/MMBtu = 309.0 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 473.7 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max hourly rate represents worst-case uncontrolled without SNCR system. Annual average is 30-day rolling average limit, based on permit No. 0510003-021-AC/PSD-FL-333**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.14 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **473.7**tons/year
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit based on 30-day rolling average.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6,695** lb/hour **1,285** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **363 ppmvd @ 7-percent O2** Reference:	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 6.5 lb/MMBtu = 6,383 lb/hr** **Annual:363 ppmvd @ 7-percent O2 equivalent to 0.38 lb/MMBtu (see PSD report)** **6,767,100 MMBtu/yr x 0.38 lb/MMBtu ÷ 2,000 lb/ton = 1,285 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Annual limit based on 12-month rolling average, based on permit No. 0510003-021-AC/PSD-FL-333**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.38 lb/MMBtu**	4. Equivalent Allowable Emissions: **6,695**lb/hour **1,285**tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit based on 12-month rolling average. Limit based on lb/MMBtu excluding periods of startup, shutdown, and malfunction (SSM). Annual tons per year limit include periods of SSM.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **51.5** lb/hour **168.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.05 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.05 lb/MMBtu = 51.5 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.026 lb/MMBtu ÷ 2,000 lb/ton = 169.2 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-021-AC/PSD-FL-333.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **51.5**lb/hour **169.2**tons/year
5. Method of Compliance: **EPA Methods 18 and 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit. Emissions representative of bagasse firing only.**	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10.72** lb/hour **12.43** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0104 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **1-hour average: 1,030 MMBtu/hr x 0.0104 lb/MMBtu = 10.72 lb/hr** **3-hour and Annual: 6,767,100 MMBtu/yr x 0.0037 lb/MMBtu ÷ 2,000 lb/ton = 12.43 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.039** lb/hour **0.13** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.8×10^{-5} lb/MMBtu** Reference: **Bagasse analysis**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **3.8×10^{-5} lb/MMBtu x 1,030 MMBtu/hr = 0.039 lb/hr** **3.8×10^{-5} lb/MMBtu x 6,767,100 MMBtu/yr = 0.13 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Emission factor based on bagasse firing only.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **H114 (Mercury)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0144** lb/hour **0.047** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.4×10^{-5} lb/MMBtu** Reference: **Bagasse analysis**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **1.4×10^{-5} lb/MMBtu x 1,030 MMBtu/hr = 0.0144 lb/hr** **1.4×10^{-5} lb/MMBtu x 6,767,100 MMBtu/yr ÷ 2,000 lb/ton = 0.047 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Emission factor based on bagasse firing only.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Fluorides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.62** lb/hour **2.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6×10^{-4} lb/MMBtu** Reference: **Similar Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **6×10^{-4} lb/MMBtu x 1,030 MMBtu/hr = 0.62 lb/hr**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on biomass firing**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION
Section [1] of [1]
Boiler No. 8

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(5), F.A.C., BACT and NSPS Subpart Db.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION
Section [1] of [1]
Boiler No. 8

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Based on 40 CFR 63, Subpart DDDDD and permit No. 0510003-021-AC/PSD-FL-333.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Based on BACT and permit No. 0510003-021-AC/PSD-FL-333**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I1 ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I2 ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I3 ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I4 ☐ Previously Submitted, Date ____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☒ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable

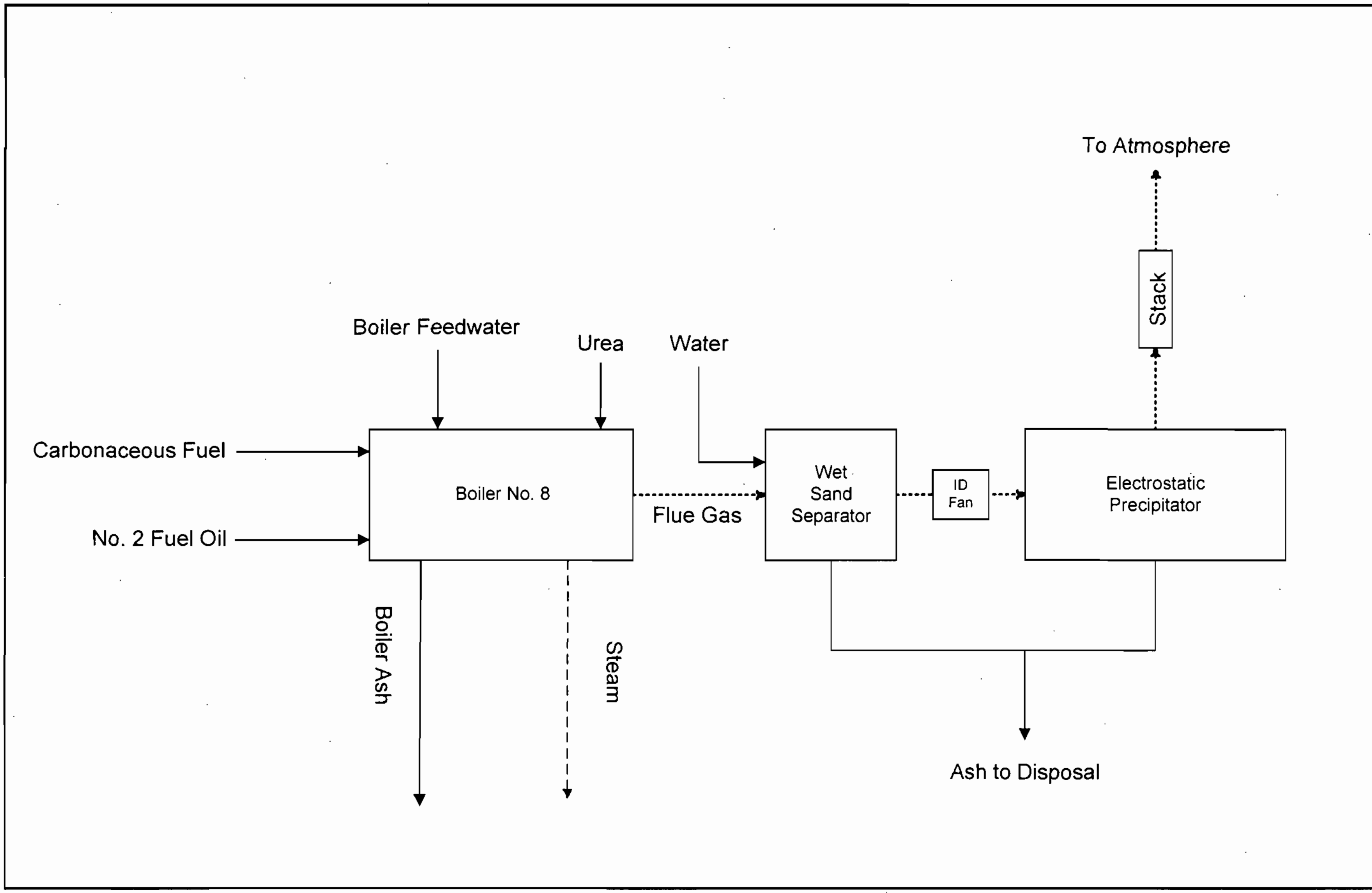
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT UC-EU1-I1

PROCESS FLOW DIAGRAM



Attachment UC-EU1-I1
Process Flow Diagram
U.S. Sugar Corporation
Clewiston Mill, Florida

Process Flow Legend
Solid/Liquid →
Gaseous ⇢
Steam ⇢

Project Number: 0237619\4\4.4\4.4.1
Filename: UC-EU1-J1.VSD
Date: 6/21/04

Golder Associates

ATTACHMENT UC-EU1-I2

FUEL ANALYSIS

Attachment UC-EU1-I2

Boiler No. 8 Fuel Analysis

Parameter	Fuel	
	Carbonaceous Fuel [a]	No. 2 Fuel Oil (0.05% S max)
Density (lb/gal)	--	6.83
Approximate Heating Value (Btu/lb)	3,600 [b]	19,910
Approximate Heating Value (Btu/gal)	--	135,000
Ultimate Analysis (dry basis):		
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% [c]
Moisture	49% - 55%	0.51% [c]

Represents typical values.

[a] Source: U.S. Sugar fuel analysis averages.

[b] Wet basis for bagasse.

[c] Source: Perry's Chemical Engineer's Handbook. Sixth Edition, 1984. Represents average fuel characteristics.

ATTACHMENT UC-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

Attachment UC-EU1-I3a
Control Equipment Parameters for Boiler No. 8
at U. S. Sugar Clewiston Mill

WET SAND SEPARATORS*

Control Device Type	Wet Cyclone
Manufacturer and Model No.	Thermal Energy Systems
Inlet Flue Gas Temp (°F)	330
Inlet Design Flue Gas Flow Rate (acfm)	230,000
Inlet Expected Flue Gas Flow Rate (acfm)	196,000
Inlet Moisture (% Volume)	25
Cyclone Diameter (ft)	22
Cyclone Height (ft)	35
No. of Spray Nozzles (Cyclone)	5
No. of Spray Nozzles (Inlet Duct)	9
Total Water Flow to Nozzles (gpm)	713
Pressure Drop (in H_2O)	4
Overall PM Collection Efficiency (%)	80

*There are two identical units operating in parallel; Data is for each unit.

Attachment UC-EU1-I3b
Control Equipment Parameters for Boiler No. 8
U. S. Sugar Clewiston Mill
ELECTROSTATIC PRECIPITATOR

Manufacturer and Model No.	PPC Industries Model No. 41R-1536-5712P		
Inlet Flue Gas Temp (°F)			330
Inlet Design Flue Gas Flow Rate (acfm)			432,500
Moisture (% Volume)			20
No. of Precipitators			1
Precipitation Type			Rigid Electrode
Total Number of Fields			5
Total Installed Collection Area (ft^2)			154,360
Gas Velocity (ft/s)			3.25
Specific Collection Area (ft^2/1,000 acfm)			356
Power Consumption (KW)			250
Pressure Drop (in H_20)			0.5
Pollutants	Inlet Loading (lb/hr)	Outlet Loading (lb/hr)	Control Efficiency %
Particulate Matter	5,346	26.8	99.5

Design Inlet loading calculation:
Uncontrolled: 5.19 lb/MMBtu x 1,030 MMBtu/hr = 5,346 lb/hr
ESP outlet loading (max) = 26.8 lb/hr (based on 0.026 lb/MMBtu)
ESP efficiency (min) = (5,346 - 26.8) / 5,346 = 99.5%

Attachment UC-EU1-I3c
Control Equipment Parameters for Boiler No. 8
U. S. Sugar Clewiston Mill
SELECTIVE NON-CATALYTIC REDUCTION SYSTEM

Manufacturer and Model No.	FuelTech		
Flue Gas Temp At Injections (°F)			1,800-2,000
Flue Gas Flow Rate (acfm)			425,000
Moisture (% Volume)			24
No. of Injection Levels			3
Total No. of Injections			28
NO_x - OUT (urea) usage (max gal/hr)			76
Maximum Ammonia Slip (ppm)			20
Pollutants	Inlet Loading (lb/MMBtu)	Outlet Loading (lb/MMBtu)	Control Efficiency %
Nitrogen Oxides	0.28	0.14	50

1. GENERAL DESCRIPTION

Boiler No.8 is fitted with two TES Non Saturating Cyclone Sand Collectors arranged in parallel so that each collector treats one half of the incoming gas stream. A general arrangement of the collectors is shown on the attached TES drawing no. CPAB-49-999-012. The collectors are located after the economiser before the induced draft fan and electrostatic precipitator.

The purpose of the collectors is to remove a large proportion of the coarse fraction of particulate carried over with the flue gas from the boiler combustion chamber to prevent excessive erosion of the induced draft fan. It is non saturating to prevent condensation of the moisture in the flue gas, and hence corrosion, as it passes through the ID fan, ESP and stack.

The collector is divided into five distinct working zones:

- a humidifying zone
- a constant pressure drop [ΔP] high velocity throat
- a cyclonic separation zone, and
- a mist elimination zone

The first process involves humidifying of the particulate laden gas by a series of spray nozzles mounted in the inlet duct. The temperature of the gas exiting the scrubber is controlled by varying the quantity of spray water to the humidifying nozzles.

The gas is then accelerated in the throat by an automatically regulated damper that maintains a constant pressure drop [ΔP] and hence constant velocity across the throat. The dust particles are separated from the gas in the cyclonic separation zone. The high 'g' forces in this zone force the particles against the wall of the cyclone where they are washed down into the collector discharge port by a series of spray nozzles that constantly keep the walls of the cyclone wet. The partially saturated gas and mist spiral upwards at low velocity through the collector. The low upward velocity allows the mist droplets to fall back into the body of the collector where they are removed with water from the wall sprays. The partially clean gas discharges from the collector through an anti-vortex device into a common duct supplying the induced draft fan.

2. MECHANICAL SPECIFICATION

The collector inlet duct and body is made from carbon steel. The inlet and scrubbing section is gunnite lined to protect it from corrosion and abrasion. Manhole ports are provided in the lower cone and the inlet section to provide maintenance access into the collector. The collector is supported on three structural steel columns. The lateral forces due to wind loads are transferred to the foundations by push/pull struts that are connected to the columns. The columns' effective length, and therefore resistance to buckling, has been reduced by tying the scrubber shell to the columns at two different levels with flat plates. the plates are flexible in the vertical plane to allow for thermal expansion of the scrubber shell relative to the structural steelwork.

A comprehensive set of galleries and ladders is included for operational and maintenance purposes.

3. PROCESS SPECIFICATION

The collector design is based on the boiler capacity and restrictions as specified in the final Air Permit No. PSD-FL-333 dated November 17, 2003.

3.1 Basic Boiler Parameters

MCR Steam Output	500,000	lb/hr
Final steam pressure	650	psig
Final steam temperature	775	°F
Maximum heat input (24 hour average)	936	MMBtu/hr

3.2 Collector Design Fuel : Bagasse

Ultimate Analysis	**% m/m**
Carbon	19.19
Hydrogen	2.24
Sulphur	0.03
Nitrogen	0.12
Oxygen	15.64
Moisture	52.28
Ash	10.50
Total	100.00
Brix	3.40 %
GCV (MMBtu/lb)	3218

The above analysis includes the moisture added by the SNCR process.

3.3 Gas Analysis at Collector inlet

The gas analysis at the inlet to the collector whilst firing design fuel in clause 3.2 at 100% MCR with SNCR urea injection is:

Component	% m/m
H_2O	19.98
CO_2	17.73
O_2	4.03
N_2	57.24
A	0.97
Total	99.95

Trace amounts of CO, SO_2, and NOx are not included in the above analysis.

3.4 Dust Burden at Collector inlet

The maximum dust burden at the collector inlet shall not exceed 25.9 lb/MMBtu.

3.5 Collector Performance

The gas flows below are combined figures for both collectors.

	Units	100% MCR	Design
Inlet Conditions			
Volume flow	Acfm	391,653	459,305
Temperature	°F	329	
Density	lb/ft^3	0.0464	
Moisture content	%m/m dry	24.97	
Dust burden	lb/MMBtu	25.94	
Outlet Conditions			
Volume flow	Acfm	359,616	421,734
Temperature	°F	248	
Density	lb/ft^3	0.0508	
Moisture content	%m/m wet	25.86	
Dust burden	lb/MMBtu	5.19	
ΔP across scrubber	Ins WG	4.0	4.0
Overall collection efficiency	%	80	80

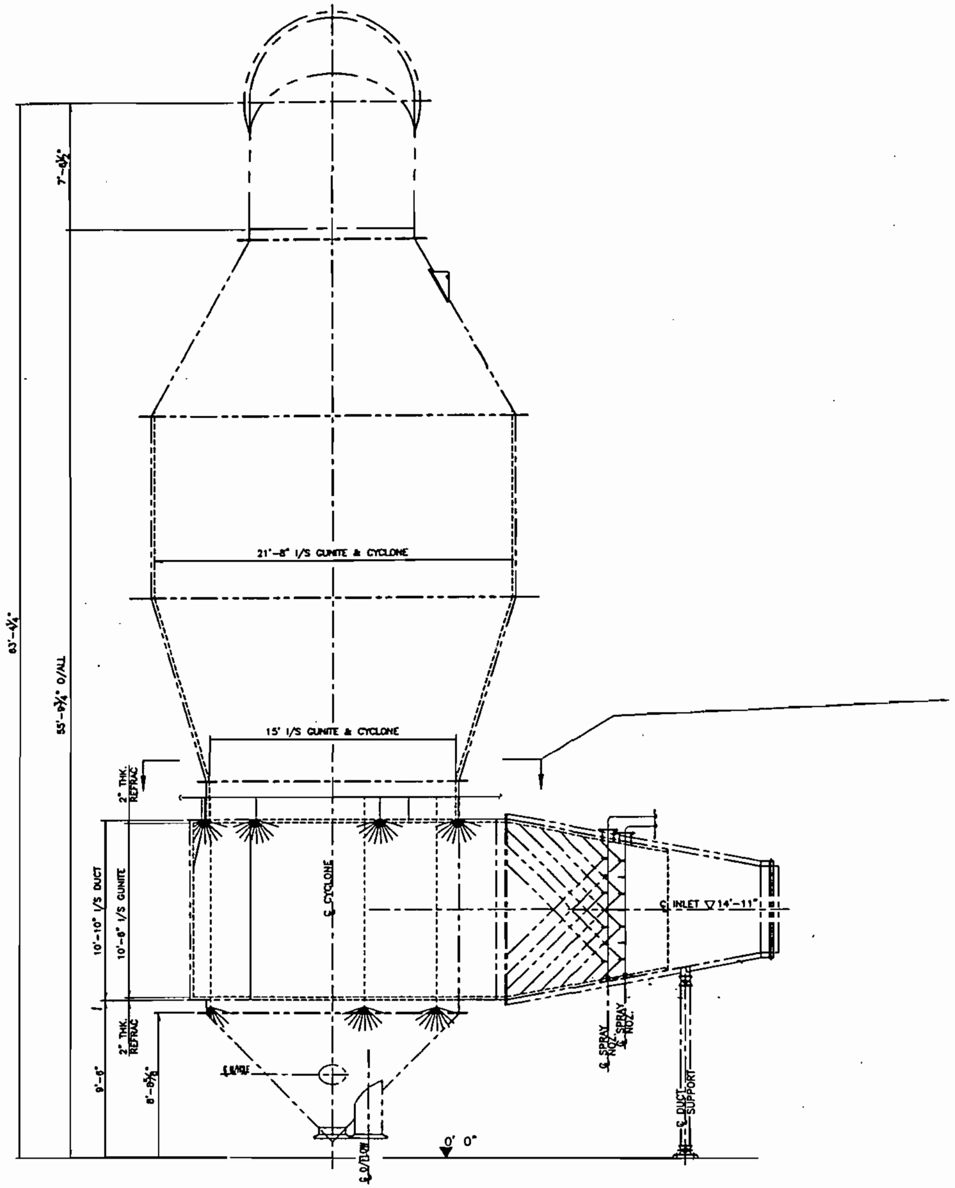
The overall collection efficiency is based upon 85% of the particles being greater than 50 microns and a standard specific gravity of 2.

3.6 Collector Spraywater requirements

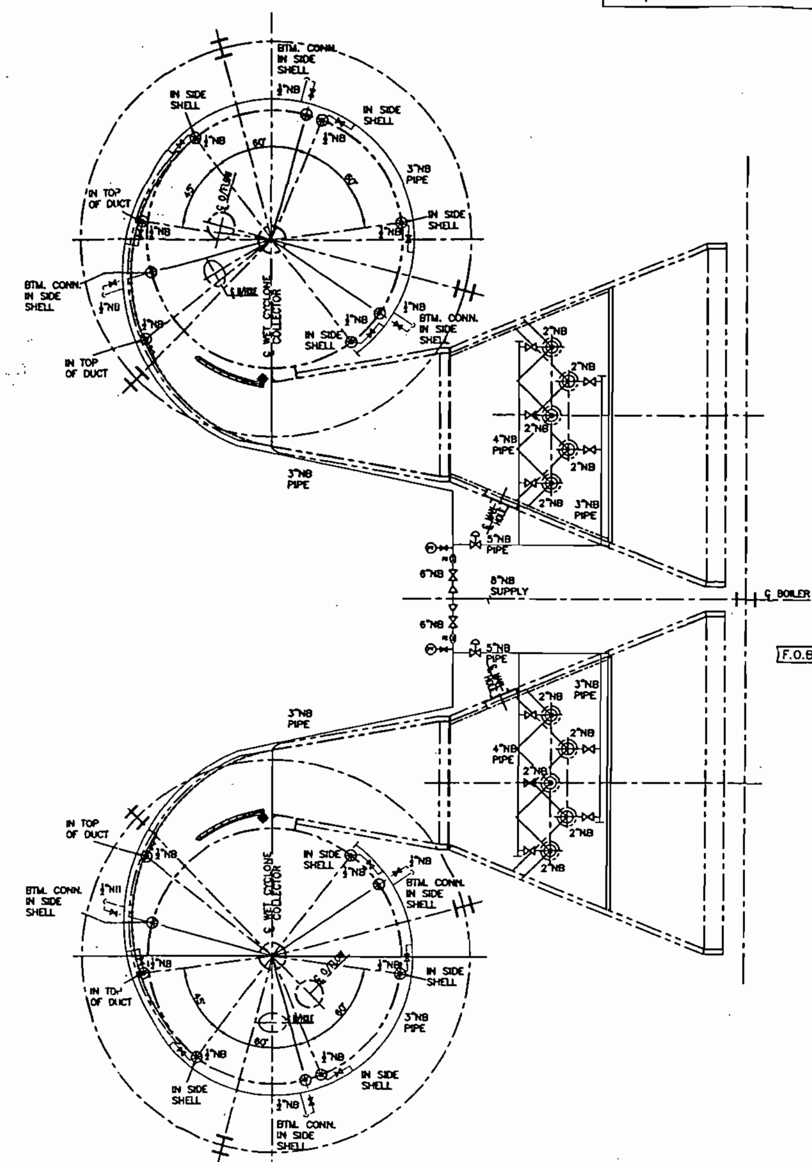
	Units	100% MCR	Design
Nozzle inlet header pressure	psig	55	70
Mass flowrate per collector	gpm	570	712.5
Mass evaporated (approx)	gpm	10	10

The spraywater quality shall be the same as that used for the collector on Boiler No.7. In particular, the pH shall be between 8 and 9.

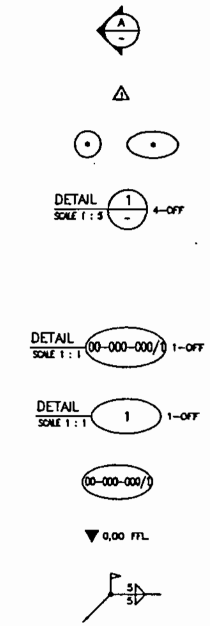
THIRD ANGLE PROJECTION



ELEVATION ON CYCLONE



PLAN ON CYCLONE



Biotherm Ltd
magasiner technology

ISSUE	DATE	INITIAL
ISSUED FOR INFORMATION ONLY. DRAWN	19/05/04	MSH
CHECKED	21/05/04	BJM
APPR	21/05/04	BJM

WORKING TOLERANCE UNLESS OTHERWISE SPECIFIED

FRACTIONS	DECIMALS	ANGLES
0 TO 4'-0" ± 1/64	.X ± .1	± 1/2
4' TO 7'-0" ± 1/32	.XX ± .03	SURFACE FINISH
OVER 7'-0" ± 1/16	.XXX ± .015	√
DO NOT SCALE	IF IN DOUBT ASK	

U.S SUGAR CORPORATION – CLEWISTON BOILER No.8 — A1

WET CYCLONE COLLECTOR EFD
500k lb/hr BAGASSE/OIL FIRED BOILER

Thermal Energy Systems

DRAWN	MSH	21/05/04	SCALE 1/4"=1'	DRG. No.: CPAB-49-999-012
CHECKED	BJM	21/05/04		
APPR	BJM	21/05/04	ISSUE	A

ATTACHMENT UC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT UC-EU1-I4

CLEWISTON BOILER NO. 8

PROCEDURES FOR STARTUP AND SHUTDOWN

Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions will be taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 8. Boiler room foreman and operating personnel will receive proper training on emissions control procedures.

Cold Startup (approximately 6 to 12 hours)

1. Turn on wet cyclone.
2. Feed clean wood into boiler combustion chamber.
3. Start fire in combustion chamber using a propane torch designed for that purpose, or light a fuel oil or natural gas burner at the lowest rate.
4. Observe the stack plume and adjust if necessary, by adjusting fuel, atomizing air, and combustion air to obtain proper combustion.
5. Feed carbonaceous fuel from the mill to the boiler slowly.
6. Energize electrostatic precipitator (ESP).
7. Activate SNCR system.
8. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fossil fuel until burners can be turned off.
9. Continue to observe the stack plume, the cyclone water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, cyclone and ESP to maintain optimum operating conditions.
10. Normally, a cold startup will require 6 to 12 hours from the first fire to normal working pressure.

Hot Startup (approximately 1 to 5 hours)

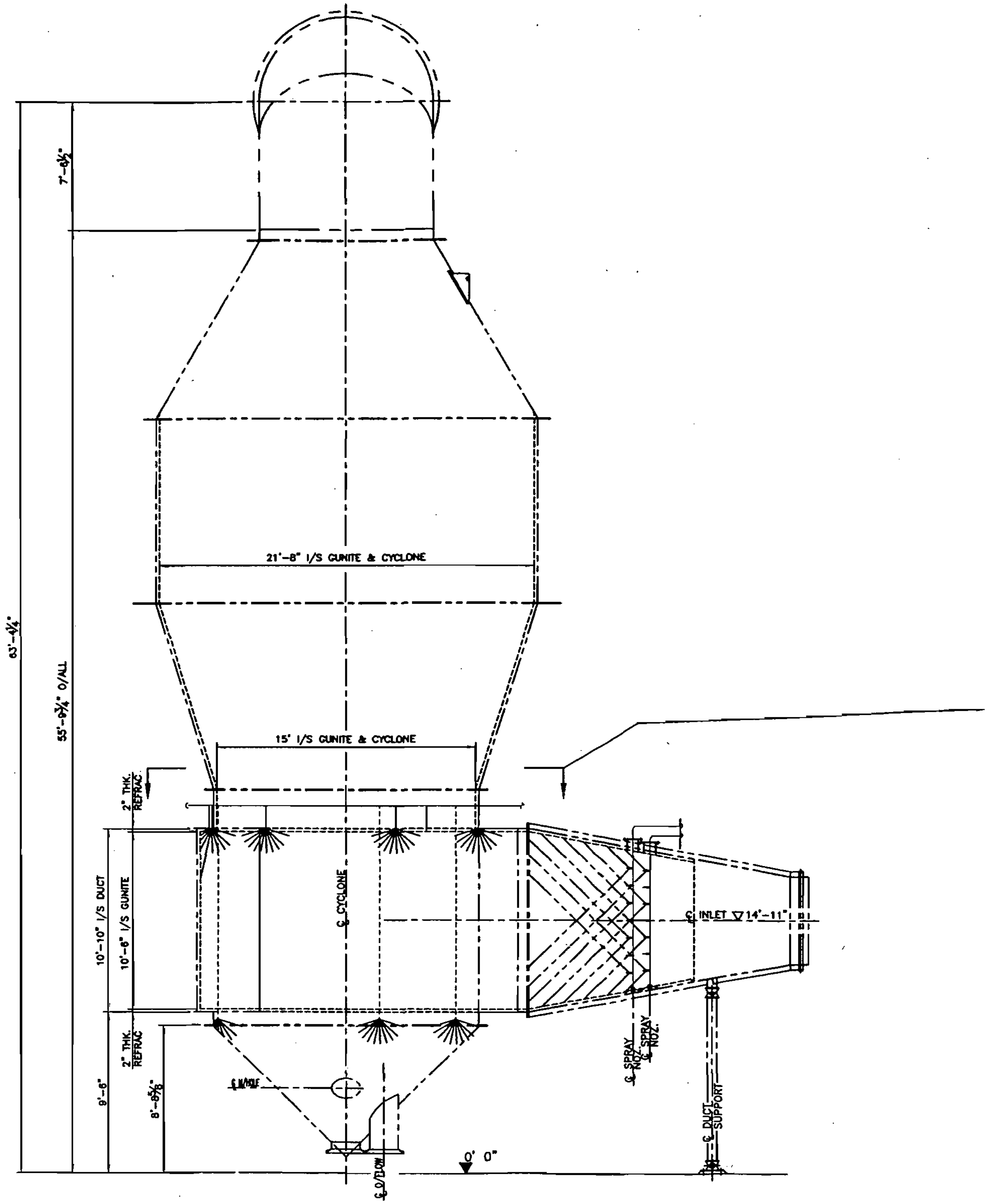
1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on wet cyclone
3. Check the boiler and cyclone water levels, and make sure they are functioning properly.

4. Light a fossil fuel burner, continue to observe the stack plume, cyclone water levels, and burners.
5. Feed carbonaceous fuel from the mill to the boiler slowly at first.
6. Energize ESP.
7. Activate SNCR system.
8. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fossil fuel until burners can be turned off. As the carbonaceous fuel fire gets hot enough to meet steam demand, reduce the fossil fuel supply until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
9. Continue to observe the stack plume, cyclone water level, and carbonaceous fuel level, making adjustments to drafts, fuel, cyclone and ESP to maintain optimum operating conditions.
10. Normally, a warm startup requires 1 to 5 hours, depending on boiler operating conditions.

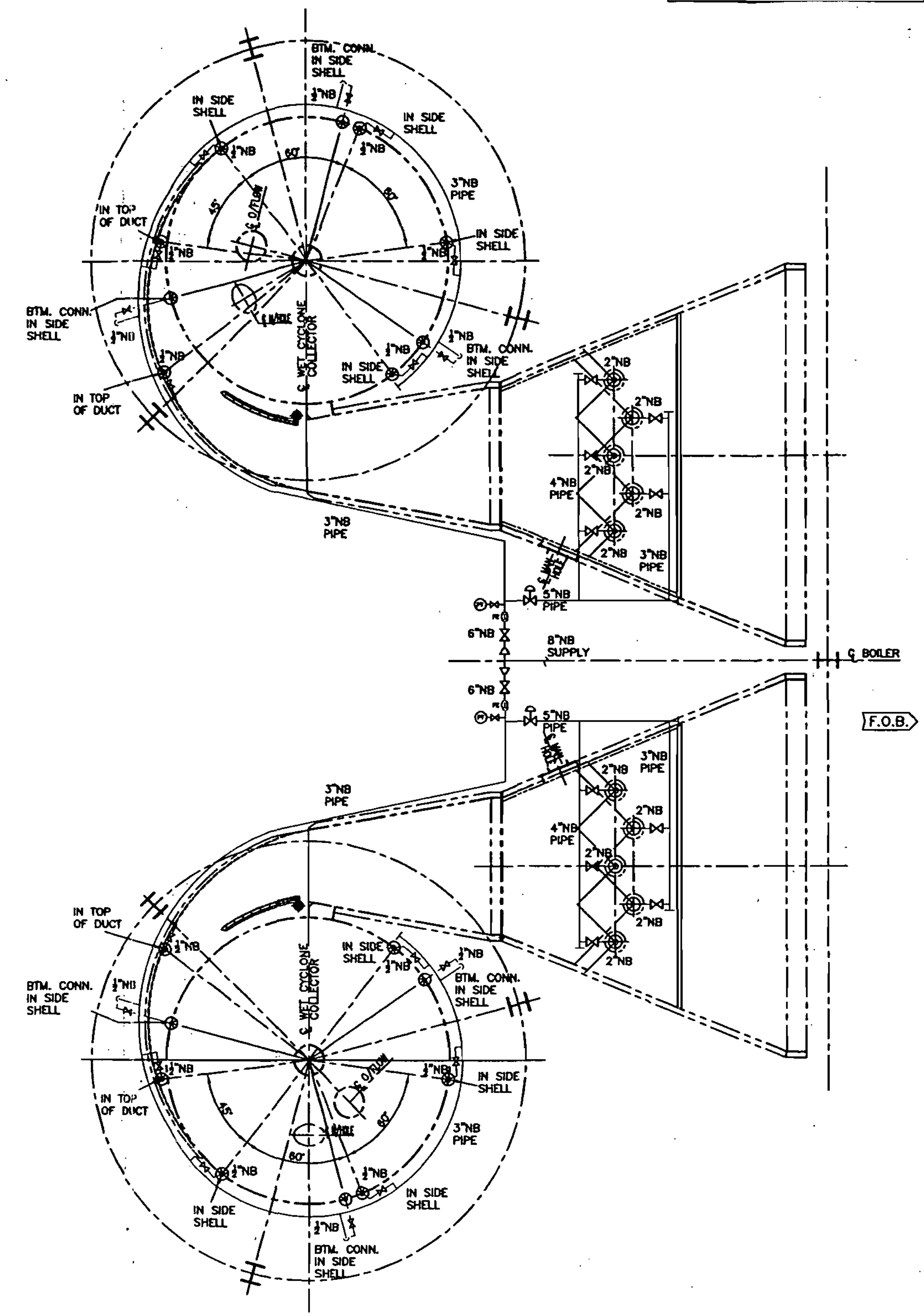
<u>Shutdown</u>

1. Stop fuel flow to the boiler, reduce forced draft, distributor air, overfire air, and induced draft.
2. Continue to observe the stack plume and cyclone water levels and make adjustments to maintain safe and optimum operating conditions.
3. After fuel flow is stopped, deactivate ESP, wet cyclone, and SNCR system.

THIRD ANGLE PROJECTION



ELEVATION ON CYCLONE



PLAN ON CYCLONE

DETAIL SCALE 1 : 5 — 4-OFF

DETAIL SCALE 1 : 1 (00-000-000/1) 1-OFF

DETAIL SCALE 1 : 1 — 1-OFF

0,00 FFL.

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ISSUED FOR INFORMATION ONLY.		
DRAWN	MSH	19/05/04
CHECKED	BJM	21/05/04
APPR	BJM	21/05/04

WORKING TOLERANCE UNLESS OTHERWISE SPECIFIED

FRACTIONS	DECIMALS	ANGLES
0 TO 4'-0" ± 1/64	.X ± .1	± 1/2°
4' TO 7'-0" ± 1/32	.XX ± .03	SURFACE FINISH
OVER 7'-0" ± 1/16	.XXX ± .015	√
DO NOT SCALE	IF IN DOUBT ASK	

U.S SUGAR CORPORATION – CLEWISTON BOILER No.8 — A1

WET CYCLONE COLLECTOR EFD
500k lb/hr BAGASSE/OIL FIRED BOILER

Thermal Energy Systems

DRAWN	MSH	21/05/04	SCALE	1/4"=1'
CHECKED	BJM	21/05/04	DRG. No.:	CPAB-49-999-012
APPR	BJM	21/05/04	ISSUE	A

SENDER: *COMPLETE THIS SECTION*

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1. Article Addressed to:

Mr. David Buff, P.E.
Golder Associates, Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Mary H Reinert ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Mary H Reinert
C. Date of Delivery 5-27-04

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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☐ Registered ☐ Return Receipt for Merchandise
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U.S. Postal Service
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OFFICIAL USE

Mr. David Buff, P.E.

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

Postmark Here

Sent To Mr. David Buff, P.E.
Street, Apt. No.; or PO Box No. 6241 NW 23rd Street, Suite 500
City, State, ZIP+4 Gainesville, Florida 32653-1500

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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1. Article Addressed to:

Mr. William A. Raiola
Vice President of Sugar Processing
Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Rachel Felton ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Rachel Felton

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
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Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To: Mr. William A. Raiola, V.P. of Sugar Processing Operations
Street, Apt. No.; or PO Box No.: Clewiston Sugar Mill and Refinery
City, State, ZIP+4: 111 Ponce DeLeon Avenue
Clewiston, Florida 33440

PS Form 3800, May 2000 See Reverse for Instructions

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 0510003-024-AC, Revised Draft Permit No. PSD-FL-333A
United States Sugar Corporation, Clewiston Sugar Mill and Refinery
Hendry County, Florida

Applicant: The applicant for this project is the United States Sugar Corporation. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is the Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

Facility Location: The applicant proposes several changes to conditions in Air Permit No. PSD-FL-333, which authorizes the construction of Boiler 8. The new boiler is being constructed at U.S. Sugar Corporation's existing Clewiston sugar mill and refinery located in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposes several changes to the air construction permit for Boiler 8 to address initial operation during the shakedown period. Shakedown is a necessary part of the construction process in which the equipment is operated, evaluated, and adjusted to achieve the design specifications. The draft permit includes several related revisions. First, the shakedown period was clarified and deadlines for demonstrating compliance were specified. The draft permit now allows up to 2 hours of operation each month without the selective non-catalytic reduction system, which controls emissions of nitrogen oxides (NOx). this will allow the plant to gather uncontrolled NOx emissions data in order to adjust the control system. The original permit included an alternate NOx emissions standard that applied only during periods uncontrolled emissions (startup, shutdown, and malfunction). It is replaced with a requirement to simply report these uncontrolled NOx emissions.

The applicant also requested authorization to fire incidental amounts of dewatered filter material from the Dissolved Aeration Flotation (DAF) system, a part of the permitted wastewater treatment system. This material will be commingled with bagasse on the existing conveyor system and distributed among the operational boilers for firing. The described changes will not result in any significant emissions increases.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.) The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-3381. The South District's telephone number is 239/332-6975.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57 F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and required, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.
521773 CGS 9/30/04

9-8-04

U.S. Sugar Corp.
Clewiston Mill

Al,

This is the revision to the PSD permit for new Boiler 8, which we discussed previously. It specifies "shakedown" requirements and allows up to 2 hours/month to operate w/o the SNCR system to gather "uncontrolled" NO_x emissions data. It also allows them to fire filter material from the WWT system which consists primarily of bagasse.

Thanks!

Jeff

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1. Article Addressed to:

Mr. William A. Raiola, V.P. of Sugar
Processing Operations
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature]
☐ Agent
☐ Addressee

B. Received by (*Printed Name*)

C. Date of Delivery
11/8/04

D. Is delivery address different from item 1? ☐ Yes
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Restricted Delivery Fee (Endorsement Required)	

Postmark
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Mr. William A. Raiola, V.P. of Sugar
Processing Operations
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

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