Adams, Patty

From: Koerner, Jeff

Sent: Wednesday, December 13, 2006 5:13 PM

To: Adams, Patty; Harvey, Mary

Subject: FW: US Sugar Boiler 8 - Capacity Increase

Yes, they called on another subject and I mentioned this one. They had not yet received due to problems with their firewall. it so I sent them just the "PDF" files. As shown below, Don Griffin responded on 12/11/06. Sorry, I should have copied you both.

Jeff

From: Don Griffin [mailto:dgriffin@ussugar.com]
Sent: Monday, December 11, 2006 8:41 AM
To: Koerner, Jeff; Peter Briggs
Cc: dave_buff@golder.com; Neil Smith
Subject: RE: US Sugar Boiler 8 - Capacity Increase

Jeff
Thanks.

Received the PDF files – we don't seem to be able to get zipped files past security. .
Thanks again
Hope you and your family have a happy holiday season

From: Koerner, Jeff [mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Monday, December 11, 2006 8:28 AM
To: Peter Briggs; Don Griffin
Cc: dave_buff@golder.com; Neil Smith
Subject: US Sugar Boiler 8 - Capacity Increase

Peter and Don,

Our secretary emailed the "zipped" files last Thursday. I know Dave Buff received the email, but if I remember correctly, US Sugar's firewall does not allow zipped files through. So, here are the individual PDF files. I am also including a MS Word version of the Public Notice. Please call if you have any questions.

Thanks!

Jeff Koerner, BAR - Air Permitting North
Florida Department of Environmental Protection
850/921-9536

<<PSD-FL-333C Boiler 8 - Intent - #0510003-037-AC-DRAFT.PDF>> <<PSD-FL-333C Boiler 8 - Draft Permit - #0510003-037-AC- DRAFT.PDF>> <<PSD-FL-333C Boiler 8 - Appendix- #0510003-037-AC-DRAFT.PDF>> <<PSD-FL-333C Boiler 8 - TEPD - #0510003-037-AC-DRAFT.PDF>> <<Signed Certificate and Cover Letter - 0510003-AC-DRAFT.pdf>> <<PSD-FL-333C Boiler 8 - Public Notice Only.doc>>

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,
DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:10 PM
To: 'NSMITH@USSUGAR.COM'; 'PBRIGGS@USSUGAR.COM'; 'DGRIFFIN@USSUGAR.COM'; 'dave_buff@golder.com'; Blackburn, Ron; 'worley.gregg@epa.gov'; 'john_bunyak@nps.gov'
Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC
Attachments: 0510003.037.AC.D_pdf.zip

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:45 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

From: Buff, Dave [mailto:DBuff@GOLDER.com]
Sent: Thursday, December 07, 2006 4:25 PM
Subject: Read: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

Your message

To: DBuff@GOLDER.com
Subject:

was read on 12/7/2006 4:25 PM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:17 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

From: Blackburn, Ron
Sent: Thursday, December 07, 2006 4:13 PM
To: Harvey, Mary
Subject: Read: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

Your message

To:	'NSMITH@USSUGAR.COM'; 'PBRIGGS@USSUGAR.COM'; 'DGRIFFIN@USSUGAR.COM'; 'dave_buff@golder.com'; Blackburn, Ron; 'worley.gregg@epa.gov'; 'john_bunyak@nps.gov'
Cc:	Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject:	Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC
Sent:	12/7/2006 4:10 PM

was read on 12/7/2006 4:13 PM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:16 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

-----Original Message-----
From: John_Bunyak@nps.gov [mailto:John_Bunyak@nps.gov]
Sent: Thursday, December 07, 2006 4:14 PM
To: Harvey, Mary
Subject: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

Return Receipt

Your document:	Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC
was received by:	John Bunyak/DENVER/NPS
at:	12/07/2006 02:14:00 PM

December 7, 2006

(Sent by Electronic Mail – Return Receipt Requested)

Neil Smith, Vice President and General Manager
Sugar Processing Operations - Clewiston Sugar Mill and Refinery
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Re: Draft Air Construction Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler No. 8 Capacity Increase

Dear Mr. Smith:

U.S. Sugar Corporation submitted an application for the existing Clewiston Sugar Mill and Refinery requesting the following for newly constructed Boiler 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. The application was made complete with the additional information provided on October 23, 2006. 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 Permitting Authority'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

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection

Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Hendry County, Florida

Applicant: The applicant for this project is the U.S. Sugar Corporation. The applicant's authorized representative and mailing address is: Mr. Neil Smith, Vice President and General Manager of Sugar Processing Operations, U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, Florida 33440.

Facility Location: U.S. Sugar Corporation operates an existing sugar mill and refinery, which is located in Hendry County at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: Boiler 8 was originally permitted as a major modification in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality. Subsequent projects must be reviewed for PSD applicability. The applicant proposes the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8: clarification of boiler startup procedures; modification of the biomass fuel handling system; and increases in the heat input and steaming rates. As constructed, this newly designed boiler is actually capable of generating 15% more steam when firing approximately 15% more fuel. Although this will result in potential increases in hourly emission rates, annual potential emissions will not increase because there will be no change in the current limitation on the annual steam production. Initial startup of Boiler 8 was March of 2005. This unit has not established normal operations for a two-year period. Pursuant to Rule 62-210.200(11), F.A.C., there will be no increase in annual emissions and the project is not subject to PSD preconstruction review.

Because the project results in increased potential maximum short-term emissions, an air quality impact analysis was conducted for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter less than 10 microns in diameter (PM_{10}), and sulfur dioxide (SO_2). For these pollutants, the initial air dispersion modeling analysis predicted ambient concentrations below the applicable PSD significant impact levels for the closest PSD Class I Area, which is the Everglades National Park. The initial air dispersion modeling analysis also predicted ambient concentrations below the applicable PSD significant impact levels for the PSD Class II Areas in the vicinity of the plant, except for the 24-hour average SO_2 value. Therefore, a refined analysis was conducted for SO_2 emissions. The subsequent modeling results showed all predicted SO_2 emissions impacts well below the applicable state and federal ambient air quality standards. The following table compares the total maximum impacts predicted in the area with the corresponding maximum allowable PSD Class II increments.

Pollutant	Averaging Time	Total Maximum Impacts ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed
SO_2	Annual	0	20	0%
	24-hour	9	91	10%
	3-hour	39	512	8%

As shown by the air quality analyses, emissions from the modified project will not significantly cause or contribute to a violation of any state or federal ambient air quality standards or PSD increments.

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 Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone 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 or phone number listed above.

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 Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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 at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or receipt of a written notice, 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 rights will be affected by the agency determination; (c) A statement of how and when the 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 for this proceeding.

(Public Notice to be Published in the Newspaper)

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Mr. Neil Smith, V.P. and General Manager
Sugar Processing Operations - Clewiston Sugar Mill and Refinery
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler 8 Capacity Increase
Hendry County, Florida

Facility Location: U.S. Sugar Corporation (applicant) operates an existing sugar mill and refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposed the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. Details of the project are provided in the 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 Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone 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 or phone number listed above.

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 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.

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 above address or phone number. 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 Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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 electronic mail (with return receipt requested) before the close of business on 12/7/06 to the persons listed below.

Mr. Neil Smith, U.S. Sugar (nsmith@ussugar.com)
Mr. Peter Briggs, U.S. Sugar (pbriggs@ussugar.com)
Mr. Don Griffin, U.S. Sugar (dgriffin@ussugar.com)
Mr. David Buff, Golder Associates (dave_buff@golder.com)
Mr. Ron Blackburn, SD Office (blackburn_r@dep.state.fl.us)
Mr. Gregg Worley, EPA Region 4 (worley.gregg@epamail.epa.gov)
Mr. John Bunyak (john_bunyak@nps.gov)

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.

Mary L. Harvey — 12/7/06
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

FROM: Jeff Koerner, Air Permitting North

DATE: November 30, 2006

SUBJECT: Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
U.S. Sugar Corporation - Clewiston Sugar Mill and Refinery
Boiler 8 Capacity Increase

U.S. Sugar Corporation submitted an application for the existing Clewiston Sugar Mill and Refinery requesting the following for newly constructed Boiler 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. Attached for your review are the Intent to Issue Permit and Public Notice Package including the Technical Evaluation and Preliminary Determination, modified Draft Permit, and P.E. Certification. I recommend your approval of the attached Draft Permit for this project. "Day 74" is January 4, 2007.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Boiler 8 Capacity Increase

PROJECT DESCRIPTION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), which is located Hendry County, Florida. Boiler 8 is newly constructed in accordance with PSD air construction Permit No. PSD-FL-333. U.S. Sugar submitted an application for the following changes: clarification of startup procedures, modifications of the biomass fuel handling system, and 15% increases in the heat input and steaming rates for the boiler as constructed. Boiler 8 had only limited operation in 2005 - 2006 and has not yet established "normal operations" for a 2-year period. As a result, the Department considers the past actual emissions from Boiler 8 to be the permitted potential emissions. Although maximum short-term emissions rates will increase, annual potential emissions remain restricted by the permit limitation on annual steam production. Therefore, the project is not subject to PSD preconstruction review. However, a revised air quality analysis was conducted, which confirmed that the increased short-term emissions rates will not cause adverse ambient impacts.

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 F. Koerner   12-7-06

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

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Project No. 0510003-037-AC
Air Permit No. PSD-FL-333C

ARMS Facility ID No. 0510003
United States Sugar Corporation
Boiler 8 Capacity Increase

COUNTY

Hendry County, Florida

APPLICANT

United States Sugar Corporation
Clewiston Sugar Mill and Refinery
Intersection of W.C. Owens Avenue and State Road 832
Clewiston, Florida

PERMITTING AUTHORITY

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

December 7, 2006

1. GENERAL PROJECT INFORMATION

Facility Description and Location

U.S. Sugar Corporation operates a sugar mill and refinery in Clewiston 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 processed in 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. The UTM coordinates are Zone 17, 506.1 E, and 2956.9 N.

Regulatory Categories

Title III: The plant is a major source of hazardous air pollutants (HAPs).

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

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

PSD: The plant is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

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

NESHAP: Boiler 8 is subject to the National Emission Standards for HAP in Subpart DDDDD of 40 CFR 63.

Application and Processing Schedule

On June 7, 2006, the Department received an application to modify the PSD air construction permit. For newly constructed Boiler 8, the applicant requests 15% increases in the heat input and steaming rates, clarification of startup procedures, and modification to the biomass fuel handling system. On June 23rd and 26th, the Department requested additional information, which included the requirement to conduct a revised air quality analysis. On September 14th, the Department extended the period of time for the applicant to provide the requested additional information. On October 23rd, the applicant provided the additional information making the application complete.

2. APPLICABLE REGULATIONS

Federal Regulations

The project is subject to applicable federal air quality regulations established by the EPA in the Code of Federal Regulations (CFR). Boiler 8 is currently subject to the New Source Performance Standards (NSPS) for industrial boilers in Subpart Db of 40 CFR 60, which regulates nitrogen oxides, particulate matter, and sulfur dioxide emissions. Boiler 8 is also subject to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for industrial boilers in Subpart DDDDD of 40 CFR 63, which regulates selected metals (or, alternatively, particulate matter), hydrogen chloride, mercury, and carbon monoxide (as a surrogate for organic HAP). The proposed project does not affect the status of Boiler 8 with respect to the existing federal regulations or impose new requirements.

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code as conditioned by Permit No. PSD-FL-333. Specifically, Boiler 8 is subject to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, which required determinations of Best Available Control Technology (BACT) for emissions of nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Therefore, this project requires a PSD applicability analysis, which is provided in the following section.

PSD Applicability Analysis

The Department regulates major stationary sources of air pollution in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) for each regulated pollutant or areas designated as "unclassifiable" for such pollutants. A facility is considered "major" with respect to PSD if it emits or has the potential to emit: ≥ 250 tons per year of any PSD pollutant; or ≥ 100 tons per year of any PSD pollutant and belongs to one of 28 PSD major facility categories; or ≥ 5 tons per year of lead.

For new projects at existing PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the "Significant Emission Rates" defined in Rule 62-212.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and subject to PSD preconstruction review. This means that the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each PSD-significant pollutant as well as evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, the project may be subject to PSD preconstruction review for several PSD-significant pollutants.

For the proposed project, the applicant requests the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8.

- As constructed, the newly designed boiler is capable of firing additional biomass and generating more steam than originally permitted. The applicant requests 15% increases in the short-term heat input and steam production rates. Although this will result in potential increases in hourly emission rates, potential annual emissions will not change because no request is made to increase the permitted annual steam production and heat input rate limitations.
- Based on actual operating data, the applicant requests clarification of the boiler startup procedures and recognition of the possibility of longer startup durations.
- The applicant proposes to modify the existing biomass fuel handling system by installing new landing zones at conveyor transfer points, covering and confining additional conveyor areas, and removing the two installed dust collectors. These improvements are predicted to reduce potential emissions.

The initial startup of Boiler 8 was in March of 2005. Since then, Boiler 8 has had only limited operation in 2005 - 2006 and has not yet established "normal operations" for a 2-year period. As a result, the Department determines the past actual emissions from Boiler 8 to be the potential emissions pursuant to Rule 62-210.200(11), F.A.C. Therefore, the project is not subject to PSD preconstruction review for the determination of BACT. However, the Department required the applicant to conduct a revised Air Quality Analysis with the increased short-term emissions rates to ensure that the project will not result in any adverse air quality impacts.

3. DEPARTMENT REVIEW

Boiler 8 Capacity Increase

The following table summarizes the capacities of Boiler 8 as specified in the current PSD permit and as requested by the applicant for this project.

Table 3A. Current Capacities Compared to Requested Capacities

Parameter	Permit No. PSD-FL-333B	Requested for Project
Design Thermal Efficiency	62%	No Change
Steam Rate, 1-Hour Maximum	550,000	633,000
Steam Rate, 24-Hour Maximum	500,000	575,000
Steam Rate, Annual Maximum	$3.6135 \times 10^{+09}$ pounds/12 months (equivalent to 6,767,100 MMBtu/year)	No Change
Heat Input Rate, 1-Hour Maximum	1030 MMBtu/hour	1185 MMBtu/hour
Heat Input Rate, 24-Hour Maximum	936 MMBtu/hour	1077 MMBtu/hour
Oil Firing Rate, 1-Hour Maximum	4161 gallons/hour	No Change
Oil Firing Rate, Daily Maximum	99,864 gallons/day	No Change
Oil Firing Rate, Annual Maximum	6,073,600 gallons/12 months	No Change

The applicant provided actual operating data from December of 2005 showing that the boiler achieved a maximum 1-hour steam rate of 572,900 lb/hour and a maximum 24-hour steam rate of 525,000 lb/hour, which are approximately 5% above the designed rates. As shown in the above table, the applicant is requesting 15% increases in the currently permitted heat input and steam rates to define the maximum capacity of the unit as constructed. The request will not affect the emissions standards specified in terms of concentrations (ppmvd), mass per heat input (lb/MMBtu), or annual emissions caps (tons/12 months). In addition, it will not result in increased annual potential emissions, which are based on a permit limitation of $3.6135 \times 10^{+09}$ pounds/12 months (equivalent to 6,767,100 MMBtu/year). However, maximum hourly emissions rates will increase as shown in the following table.

Table 3B. Comparison of Emissions Increases for Regulated Pollutants

Pollutant	Process-Based Standards	Maximum Emissions Rates, lb/hour [d]		Annual Potential Emissions
		Current [a]	Requested [b]	Tons/Year [c]
CO	400 ppmvd @ 7% oxygen, 30-day avg.	409.2	470.6	1285
	1285 tons/12 months	---	---	1285
HCl	0.02 lb/MMBtu, 3-hour test	18.7	21.5	67.7
Hg	0.000003 lb/MMBtu, 3-hour test	0.0028	0.0032	0.0102
NO_X	0.14 lb/MMBtu, 30-day avg.	131.0	150.8	473.7
PM	0.025 lb/MMBtu, 3-hour test	23.4	26.9	84.6
SO_2	0.06 lb/MMBtu, 3-hour test	56.2	64.6	203.0
VOC	0.05 lb/MMBtu, 3-hour test	46.8	53.9	169.2

a. As specified in the permit, current hourly emissions rates are based on the maximum 24-hour heat input rate of 936 MMBtu/hour.

b. Requested hourly emissions rates are based on the requested maximum 24-hour heat input rate of 1077 MMBtu/hour.

c. Annual potential emissions are based on the "process-based standards" and the permitted maximum annual heat input rate of 6,767,100 MMBtu/year. Annual potential emissions will not change.

d. For the air quality modeling analysis, higher emissions rates were used for any averaging period of less than 24 hours.

The newly constructed unit has a larger capacity than the original design. There are no physical or operational changes necessary to achieve the higher heat input and steam rates. The increased hourly emissions rates were modeled and showed no adverse ambient impacts. Compliance with the CO and NOx standards are demonstrated with CEMS data. For PM, SO_2, VOC, and opacity, the current permit requires compliance stack tests to be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate. Therefore, the Department will revise the permit to specify that the new boiler capacity will become effective once the permittee satisfactorily demonstrates compliance with the standards for PM, SO_2, VOC, and opacity at the higher capacity.

Boiler 8 Revised Startup Procedures

Appendix F of the PSD permit identifies good combustion and operating practices to minimize emissions of carbon monoxide and volatile organic compounds from Boiler 8 and promote good combustion and pollution control. To the extent practicable, the permittee must employ these practices, which include careful monitoring of oxygen and CO flue gas levels, ensuring sufficient oxygen to promote good combustion, and maintaining the controls for particulate matter and NOx emissions throughout the normal operating ranges of this equipment. The original PSD permit identified the following startup procedure for Boiler 8.

"*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 (and/or wood chips) 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 (and/or wood chips)."

As constructed, the applicant indicates that it is necessary to achieve a superheater steam temperature of 650° F before boiler components reach the desired operating temperatures, which may take up to 6 to 7 hours of firing distillate oil if the boiler is cold. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. Then, biomass is fed until an even fire is established across the entire grate, which can take another 1 to 3 hours to establish the full steaming rate. So, it is possible that a boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired. The applicant requests that the identified startup procedures be revised accordingly.

During startup, boiler conditions are unsteady until a uniform bed of burning biomass is established and process and control equipment achieve normal operating temperatures. To support this statement, the applicant provided actual operating data for four startups from 8 to 11 hours in duration. During the last few hours when transitioning from distillate oil to biomass, operating levels were shown to vary widely before stabilizing. For example, flue gas oxygen levels may swing from 4% to 19% and carbon monoxide levels may spike at over 3000 ppmvd after being less than 200 ppmvd for several hours. Therefore, the Department agrees to revise the description of startup procedures in Appendix F.

To follow up, the Department reviewed the PSD permit to determine whether the revised startup procedures will affect other permit conditions. Because opacity is readily observable and compliance with the standards for CO and NOx is demonstrated by CEMS, the PSD permit currently specifies the following for startup:

Alternate Opacity Standard: "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."

CO Emissions: "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). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements." The Subpart DDDDD provisions state, "Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity."

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:

- Best operational practices are used to minimize emissions; and
- For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional."

Except for the CO emissions cap, the PSD permit conditions currently allow the exclusion of elevated CO and NOx emissions data due to startup provided that best operational practices are used to minimize emissions and the control equipment is placed in service as soon as operating conditions allow. Therefore, no other changes to the permit are necessary.

Biomass Handling System

To control dust from the biomass handling systems, the original project included mostly enclosed conveyors and the installation of five dust collectors to control transfer points. So far, only two dust collectors have been installed because of issues with frequent plugging and high maintenance efforts as well as the associated costs. The applicant has determined that the conveyor transfer points cause unnecessary movement of the conveyor belts, which generates excessive dust. The applicant proposes to modify the existing system by installing new landing zones at conveyor transfer points, covering and confining additional exposed areas, and removing the existing dust collectors.

The new landing zones will provide support for the belts to reduce vibrations and minimize the generation of dust. The conveyor system will now be completely enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The improvements are anticipated to reduce fugitive dust from this system as well as maintenance costs. The application for the original PSD permit estimated approximately 7.5 tons per year of particulate matter from the baghouse exhausts based on the maximum design outlet loadings and the maximum flow rates. Based on standard AP-42 emissions factors, the applicant indicates that the proposed changes will result in potential particulate matter emissions of less than 5 tons per year. The Department approves the changes and will revise the permit accordingly.

Summary of Revisions

The following provides a brief summary of changes to the original PSD permit, as modified:

- *Placard Page*: Update the project description under the "Statement of Basis".
- *Section I, General Information*: Update "Project Description" and "Relevant Documents" list.
- *Section II, Administrative Requirements*: Update revised regulations Conditions 7 and 9.
- *Section III, Subsection A, Boiler 8 (EU-028)*: Update the emissions unit description. Throughout this subsection, revise the heat input and steam production rates. In Conditions 3 and 22, update to include the new dry cyclone authorized in Permit No. 0510003-035-AC. In Condition 7, update the mass emissions rates (lb/hour) based on the revised maximum 24-hour heat input rate. In Condition 14, add the requirement pursuant to Rule 62-297.310(2), F.A.C. that the boiler is limited to 110% of its latest operational rate during compliance testing until new testing is conducted within 90% to 100% of the revised maximum 24-hour heat input rate.
- *Section III, Subsection B, Biomass Handling System (EU-027)*: In Condition 2, update to reflect that the biomass handling system will be modified by installing new landing zones at conveyor transfer points, covering and confining additional exposed areas, and removing the existing dust collectors. In Conditions 3 and 4, update to include the existing bagacillo cyclone as a unit regulated for opacity.
- *Appendix D, NSPS Provisions*: Update emissions unit description for revised steam production rate.
- *Appendix E, Summary of Final BACT Determinations*: Update to reflect the revised heat input and steam production rates, the modified biomass handling system, and the existing bagacillo cyclone.
- *Appendix F, Good Combustion and Operating Practices*: Update for revised Boiler 8 startup procedures.
- *Appendix J, NESHAP Provisions*: Update emissions unit description for revised steam production rate.

4. AIR QUALITY ANALYSIS

Introduction

Although the project will not increase annual emissions, it will increase maximum short-term emissions. Therefore, the air quality impacts due to the short-term increases were evaluated for the following four pollutants: SO_2, NO_x, PM_{10} and CO. PM_{10}, SO_2 and NO_x are criteria pollutants and have defined national and state ambient air quality standards (AAQS), PSD increments and significant impact levels. CO is a criteria pollutant with only defined AAQS and significant impact levels. A discussion of the required air quality analyses follows.

Models and Meteorological Data Used in the Air Quality Impact Analysis

<u>PSD Class II Area Model</u>

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for annual, 24, 8, 3 and 1-hour averaging periods. A series of specific model features, recommended by the EPA, are referred to as the regulatory options and were used by the applicant. Since some of the associated stacks are less than the good engineering practice (GEP) stack height criteria, the applicant evaluated the potential for building downwash to occur in the air modeling analyses.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at Palm Beach International (PBI) Airport and twice-daily upper air soundings collected at the Florida International University (FIU) in Miami. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

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

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

PSD Class I Area Model

The nearest PSD Class I area to the Clewiston Mill site is the Everglades National Park (ENP), located about 102 kilometers to the south at its closest point. Since this Class I area is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. 2001 through 2003, 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions changes. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the AAQS or PSD increments. To determine whether there were significant impacts from PM_{10}, SO_2, CO and NOx emissions due to the proposed project, concentrations were predicted using nested Cartesian receptor grids for receptor locations in the Class II area in the vicinity of the project. More than 4,000 receptors located at the Mill's restricted property line and offsite were used. For determining predicted impacts in the ENP PSD Class I area, 251 receptors in the ENP were used.

The tables below show the results of this modeling. Significant impacts were predicted in the Class II area in the vicinity of the project for only SO_2 and for only the 24-hour averaging time. Therefore, further SO_2 AAQS and PSD increment analyses within the predicted significant impact area were required for this project. No significant impacts were predicted in the PSD Class I area; therefore, no further analyses were required in the PSD Class I area.

Maximum Project Air Quality Impacts for Comparison
to PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact
PM_{10}	Annual	0.2	1	No
	24-hour	2.6	5	No
SO_2	Annual	0.5	1	No
	24-hour	6.2	5	Yes
	3-hour	9.3	25	No

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact
NO_x	Annual	0.9	1	No
CO	8-hour	422	500	No
	1-hour	487	2000	No

Maximum Project Air Quality Impacts for Comparison to
PSD Class I Significant Impact Levels in the ENP Class I Area

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact
PM_{10}	Annual	0.001	0.2	No
	24-hour	0.034	0.3	No
SO_2	Annual	0.003	0.1	No
	24-hour	0.080	0.2	No
	3-hour	0.306	1.0	No
NO_x	Annual	0.003	0.1	No

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding "background" concentrations to the maximum modeled concentrations for each pollutant and averaging time. The maximum modeled concentrations are based on the maximum allowable emissions from facility sources and all other sources in the vicinity of the facility. The background concentrations take into account all sources of a particular pollutant that are not explicitly modeled. They are based on recent air quality monitoring data concentrations collected in the vicinity of the project. Even though SO_2 impacts were only significant for the 24-hour averaging period, AAQS impacts were also determined for the 3-hour and annual averaging times. The results of the AAQS analysis for SO_2 are summarized in the table below and show no predicted violations of the AAQS.

Ambient Air Quality Impacts

Pollutant	Averaging Time	Modeled Sources Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)	Total Impact Greater Than AAQS?
SO_2	Annual	8	3	11	60	No
	24-hour	33	5	38	260	No
	3-hour	75	13	88	1,300	No

PSD Class II Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration as established in 1977 for SO_2. The actual baseline year used in this determination was 1975 for existing major sources of SO_2. The emission values that are input into the model for predicting increment consumption are based on maximum potential emissions from increment-consuming facility sources and all other increment-consuming sources in the vicinity of the facility. The maximum predicted PSD Class II area SO_2 increments consumed by this project and all other increment-consuming sources in the vicinity of the facility are shown below. As was done for the AAQS evaluation, maximum 3-hour and annual average SO_2 impacts were also predicted. As shown in the table, there are no predicted impacts greater than the allowable increments.

PSD Class II Increment Analysis

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact > Allowable Increment?
SO_2	Annual	0	20	No
	24-hour	9	91	No
	3-hour	39	512	No

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. An air quality modeling analysis was not required because the project will not result in an increase in emissions. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Cleve Holladay is the staff meteorologist responsible for reviewing and approving the air quality analysis. 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-333C Boiler 8 - TEPD}

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-333C Project No. 0510003-037-AC Facility ID No. 0510003 Permit Expires: {Date}

FACILITY AND LOCATION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), 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 processed in 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 was recently constructed under Permit No. PSD-FL-333, as modified. This permitting action is a revision of the air construction permit to specifically address the following items for this unit: increases in the heat input and steaming rates; clarification of startup procedures; and modification of the biomass fuel handling system. 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

DRAFT

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

PROJECT DESCRIPTION

Boiler 8 (EU-028) is a new spreader-stoker boiler with a maximum heat input rate of ~~1030~~ 1185 MMBtu per hour. It will fire bagasse as the primary fuel and wood chips as an alternate or supplemental 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. Low sulfur fuels (i.e., bagasse, wood chips, and distillate oil) will be used to minimize potential 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 biomass handling system (EU-027), biomass conveyors will be enclosed and new landing zones ~~dust collectors~~ installed on conveyor transfer points.

REGULATORY CLASSIFICATION

Title III: The existing facility is a 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 in Subpart Db of 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for HAP in Subpart DDDDD of 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 Provisions

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. **Incidental Amounts of On-Specification Used Oil with Bagasse**

Appendix J. NESHAP Provisions

RELEVANT DOCUMENTS

The applications, correspondence, and permits related to the following projects are considered relevant documents: original Project No. 0510003-021-AC (PSD-FL-333), revised Project No. 0510003-024-AC (PSD-FL-333A), Project No. 0510003-030-AC (PSD-FL-333B), and Project No. 0510003-037-AC (PSD-FL-333C). Relevant documents are not a part of this permit, but include information specifically related to this permitting action and are on file with the Department.

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of each application shall be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.

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(12)(a)~~(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.]~~

9. <u>Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]</u>

10. <u>Modifications</u>: 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. <u>Title V Permit</u>: 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 to the appropriate Permitting Authority the application form, compliance test results, and such additional information as the Department may by law require. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

A. Boiler 8 (EU-028)

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). Wood chips will be fired as an alternate or supplemental fuel (SCC No. 1-02-009-02). 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~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 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 to 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~~ 315° F and a volumetric flow rate of ~~400,000~~ 395,000 acfm at ~~5.5~~ 7% oxygen (~~225,000~~ 270,000 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(8), F.A.C.; and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) of Subpart DDDDD (industrial boilers) in 40 CFR 63, which is adopted by reference in Rule 62-204.800(11), F.A.C.}

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 (PSD), 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~~ 633,000 pounds per hour based on a maximum 1-hour heat input rate of ~~1030~~ 1185 MMBtu per hour.** Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse and/or wood chips. 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 t~~Two wet and one dry cyclone collectors are installed 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 and/or wood chips 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 (PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary fuel, wood chips as an alternate or supplemental 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 on-specification used oil commingled with bagasse may be 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 (PSD), F.A.C.]

5. Boiler Capacities and Restrictions: The hours of operation are not restricted (8760 hours/year). The maximum continuous steam production capacity (24-hour average) is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 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~~ 13,800,000 pounds of steam per day (equivalent to ~~500,000~~ 575,000 pounds of steam per hour and ~~936~~ 1077 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).

   {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; Rules 62-4.070(3), 62-212.400 (PSD), 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 (PSD), 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, wood chips, 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 (PSD), 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. [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~~ 150.8 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 (PSD), 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 (PSD), F.A.C.]

   e. Particulate Matter (PM/PM_{10}): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.025 lb/MMBtu and ~~23.4~~ 26.9 pounds per hour. [Rule 62-212.400 (PSD), F.A.C.; 40 CFR

63.7500]

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~~ 64.6 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400 (PSD), 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~~ 53.9 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 (PSD), F.A.C.]

h. Hydrogen Chloride (HCl): As determined by EPA Method 26 or 26A stack test, HCl emissions shall not exceed 0.02 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7500]

i. Mercury (Hg): As determined by the fuel analysis requirements specified in §63.7521 and Table 6 of Subpart DDDDD in 40 CFR 63, mercury emissions shall not exceed 0.000003 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7521]

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

   a. Carbon Monoxide (CO):

      1) As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 7% oxygen based on a 30-day rolling average. Carbon monoxide emission levels must be maintained below this work practice standard at all times except during periods of startup, shutdown, malfunction, and when the boiler or process heater is operating at less than 50% of rated capacity. For purposes of calculating data averages, data recorded during the following periods must not be used: periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler is operating at less than 50% of its rated capacity. All the data collected during all other periods must be used in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements. [40 CFR 63.7500(1), 63.7525(a)(6), 63.7540(a)(10) and Table 1 of Subpart DDDDD]

      2) 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 (PSD), 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 (PSD), 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*: 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). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements.

    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 nitrogen oxides are provided during specific* *periods in which the control device may not be fully operational 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. Compliance with the NESHAP Subpart DDDDD provisions for CO emissions shall be determined in accordance with the federal regulations. The Department's rules and permits cannot waive or supersede a federal requirement.}*

TESTING REQUIREMENTS

13. Boiler Performance Test: Within 180 days of first fire on bagasse, the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted when firing only bagasse and shall be at least three hours long. The 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 or bagasse with wood chips. 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.

    Permit No. PSD-FL-333C modified the maximum heat input and steaming rates for Boiler 8. Pursuant to Rule 62-297.310(2), F.A.C., operation of Boiler 8 is limited to 110% of the latest test rate until a new test is conducted within 90% to 100% of the revised maximum 24-hour heat input rate that demonstrates compliance with the emissions standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. 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.

    {Permitting Note: All initial tests must be conducted at permitted capacity, ~~between~~ which is defined as 90% ~~and~~ to 100% of the maximum 24-hour heat input rate ~~permitted capacity~~; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.} [Rules 62-212.400 (PSD) 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 CO test 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 (PSD), 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 (PSD), 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 (or electronic) 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/Wood Chips*: Representative samples of bagasse and wood chips (if stored on site) 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, operated and maintained in accordance with the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.

    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 (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. *NESHAP Averaging (CO).* CO emissions shall be monitored and recorded pursuant to the applicable requirements in Subpart DDDDD of 40 CFR 63.

    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).* For each day (midnight to midnight), the CEMS shall record the total CO mass emissions rate (pounds per day). 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 (PSD), F.A.C.; NESHAP Subpart DDDDD]

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 (PSD), F.A.C.; 40 CFR 63.7500]

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 (PSD), F.A.C.]

22. ~~Wet~~ Cyclones: 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) for each wet cyclone and a manometer (or equivalent) to monitor the pressure drop (inches of water) across each cyclone. 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 (PSD), F.A.C.; 40 CFR 63.7500]

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), wood chip 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 (PSD), 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 provisions.

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". Appendix J of this permit summarizes these provisions.

B. Biomass Handling System (EU-027)

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

ID	Emission Unit Description
027	Biomass Handling System

EQUIPMENT

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

2. ~~Air Pollution Control~~ Equipment: To minimize fugitive particulate matter, biomass conveyors shall be enclosed and ~~. Dust collectors~~ new landing zones shall be installed on conveyor transfer points. The conveyor system will now be completely enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. A cyclone separates the particles from the gas stream, which exhausts to ambient air. The fine particles are used as part of the cake material on the vacuum filters. ~~The preliminary design for the biomass 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 dust collectors described above will be installed.}*~~ [Design; Application No. 0510003-037-AC]

EMISSIONS STANDARDS

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

TESTING REQUIREMENTS

4. Opacity Tests: ~~Within 180 days of completing construction of the biomass 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~~ In accordance with EPA Method 9, the bagacillo cyclone exhaust shall be tested during each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the opacity standard. [Rules 62-212.400 (PSD) 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.]

SECTION 4. APPENDICES

Contents

SECTION 4. APPENDIX A

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

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, F.A.C.]

NSPS Provisions

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(8), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of ~~500,000~~ 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

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(8), 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.}

§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.}*

(c) On and after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

  (1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

  (2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(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 for oil firing 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 ($\leq$ 0.5% sulfur by weight) is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

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

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

(a) The particulate matter emission standards and 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.

(b) Compliance with the particulate matter emission standards under Sec. 60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(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:

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160° C (320° F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets

(iii) Method 5B is to be used only after wet FGD systems.</SUP>

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160° C (320° F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Method 9 is used for determining the opacity of stack emissions.

{Permitting Note: NSPS Subpart Db imposes only a particulate matter and 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.}*

<u>§60.49b Reporting and Recordkeeping Requirements</u>

(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~~ 633,000 pounds per hour based on a maximum 1-hour heat input rate of ~~1030~~ 1185 MMBtu per hour. The maximum continuous steam production is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 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 (and wood chips as an alternate or supplemental fuel). 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.

Biomass Handling System: To minimize fugitive particulate matter from the biomass handling system, biomass conveyors will be enclosed and ~~dust collectors~~ new landing zones will be installed on the conveyor transfer points. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. A cyclone separates the particles from the gas stream, which exhaust to ambient air. The fine particles are used as part of the cake material on the vacuum filters.

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: Biomass Handling System		
Opacity [c]	There shall be no visible emissions (≤ 5% opacity) from the ~~dust collector~~ bagacillo cyclone exhaust outlets.	
EU-028: Boiler 8		
CO [d]	Good Combustion Practices	1285 tons per consecutive 12 month rolling total (Avoids PSD Review)
NOx	0.14 lb/MMBtu {Initial demonstration standard; subsequent compliance based on CEMS.}	0.14 lb/MMBtu, 30-day rolling average
PM	0.025 lb/MMBtu [e]	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, wood chips, 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, wood chips, 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 applicable requirements in Subpart DDDDD of 40 CFR 63. 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 and/or wood chips. 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.

e. The original PSD permit considered the proposed particulate matter standard for new, large solid fuel fired boilers specified in NESHAP Subpart DDDDD (0.026 lb/MMBtu). The final version of this regulation revised the particulate matter standard to 0.025 lb/MMBtu. For simplicity and clarity, the applicant specifically requested that the BACT standard be reduced to be equivalent to the NESHAP standard. Permit No. PSD-FL-333B revised the standard accordingly.

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 as well as subsequent revisions.

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~~ 6 to 7 hours to reach the desired superheater steam temperature of ~~500~~ 650° F. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. ~~Once this temperature is reached~~ Then, bagasse (and/or wood chips) will be fed until a fire is established across the entire grate. The full steaming rate can be reached about ~~30 to 60 minutes~~ 1 to 3 after first feeding bagasse (and/or wood chips). A boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired.
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 and/or wood chips are 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 and/or wood chips during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen. 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 bagasse and/or wood chips, 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 and/or wood chips 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 solid fuel 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) Wood chips: alternate or supplemental fuel

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: _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. 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 and/or wood chips as an alternate or supplemental fuel. 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, wood chips as an alternate or supplemental fuel, and 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 and/or wood chips. 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.}

SECTION 4. APPENDIX I

Incidental Amounts of On-Specification Used Oil with Bagasse and/or Wood Chips

Description

The facility generates small amounts of on-specification used oil consisting mostly of hydraulic fluids and lubrication oils (<< than 10,000 gallons per year). Leaks or spills of these fluids are removed from the work areas by absorbing with bagasse and/or wood chips and then adding to the common biomass conveyor for firing in any of the boilers. The amount of oil is incidental and would not affect emissions.

Requirements

1. Firing: The permittee may fire incidental amounts of bagasse/on-specification oil with other authorized fuels in any of the mill boilers. To the extent practicable, the bagasse/on-specification oil shall be commingled with bagasse and/or wood chips in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C.]
2. Used Oil Specifications: Incidental amounts of used oil to be fired in the boilers shall be on-specification used oil 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]
3. 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.]

The following emissions unit is subject to applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63 and adopted by reference in Rule 62-204.800(11), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of ~~500,000~~ 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 63, Subpart A - NESHAP General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the National Emission Standards for Hazardous Air Pollutants including: §63.1 Applicability; §63.2 Definitions; §63.3 Units and abbreviations; §63.4 Prohibited activities and circumvention; §63.5 Preconstruction review and notification requirements; §63.6 Compliance with standards and maintenance requirements; §63.7 Performance testing requirements; §63.8 Monitoring requirements; §63.9 Notification requirements; §63.10 Recordkeeping and reporting requirements; §63.11 Control device requirements;§63.12 State authority and delegations; §63.13 Addresses of State air pollution control agencies and EPA Regional Offices; §63.14 Incorporations by reference; §63.15 Availability of information and confidentiality; §63.16 Performance Track Provisions. The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters

Boiler 8 shall comply with all applicable requirements of Subpart DDDDD in 40 CFR 63, which are adopted by reference in Rule 62-204.800(11), F.A.C. For purposes of this regulation, Boiler 8 is classified as a new, large (> 100 MMBtu/hour), solid fuel (bagasse) industrial boiler. As such, the unit is subject to the following primary requirements:

Pollutant	Emission Limits	Requirements
Particulate Matter (PM)	0.025 lb/MMBtu of heat input	• Surrogate limit for total selected metals (TSM) • Compliance by EPA Method 5 stack test • Compliance test establishes allowable "operating limits" (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • Continuous compliance by continuous monitoring (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • A COMS is not required due to the wet cyclone scrubber
Hydrogen Chloride (HCl)	0.02 lb/MMBtu of heat input	• Compliance by EPA Method 26 or 26A stack test • Monitoring is same as for particulate matter • Scrubber pH monitoring not required (EPA Region 4 letter dated September 4, 2005)
Mercury (Hg)	0.000003 lb/MMBtu of heat input	• Compliance by fuel sampling and analysis methods
Carbon Monoxide (CO)	400 ppmvd @ 7% oxygen (30-day rolling average)	• Surrogate limit for organic HAPs • Compliance by data collected from CO CEMS • CEMS shall be installed, operated and maintained in accordance with the provisions of §63.7525

The following pages contain a table of contents for NESHAP Subpart DDDDD as well as the summary tables from this Subpart that are applicable to Boiler 8.

TABLE 1. Emission Limits and Work Practice Standards

As stated in §63.7500. Boiler 8 shall comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
1. New Large Solid Fuel	a. Particulate Matter (for Total Selected Metals)	0.025 lb per MMBtu of heat input
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input
	c. Mercury	0.000003 lb per MMBtu of heat input
	d. Carbon Monoxide	400 ppmvd corrected to 7 percent oxygen (30-day rolling average) based on data collected from a CO CEMS

The following provisions cover periods of startup, shutdown, and malfunction.

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §63.7 and §63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §63.7525(a) and §63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §63.6(e) and §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

TABLE 2. Operating Limits for Boilers with Particulate Matter Emission Limits

As stated in §63.7500, Boiler 8 shall comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet Scrubber Control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
3. Electrostatic Precipitator Control	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

TABLE 4. Operating Limits for Boilers with Hydrogen Chloride Limits

As stated in §63.7500, Boiler 8 shall comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet Scrubber Control	Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 5. Performance Testing Requirements (Particulate Matter and Hydrogen Chloride)

As stated in §63.7520, Boiler 8 shall comply with the following performance test requirements:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure particulate matter emissions concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen Chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).

To conduct a performance test for the following pollutant	You must	Using
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the HCl concentration.	Method 26 or 26A in appendix A to part 60.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

TABLE 6. Fuel Analysis Requirements (Mercury)

As stated in §63.7521, Boiler 8 shall comply with the following fuel analysis testing requirements:

To conduct a fuel analysis for the following pollutant	You must	Using
1. Mercury	a. Collect fuel samples (The permittee notes that samples will be taken from a moving belt.)	Procedure in §63.7521(c) or ASTM D2234-001 (for coal)(IBR, see §63.14(b)) or ASTM D6323-98 (2003)(for biomass)(IBR, see §63.14(b)) or equivalent
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent
	c. Prepare composite fuel samples	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) (IBR, see §63.14(b)) or ASTM D5198-92 (2003) (for biomass)(IBR, see §63.14(b)) or equivalent
	d. Determine heat content of the fuel type	ASTM D5865-03a (for coal)(IBR, see §63.14(b)) or ASTM E711-87 (1996) (for biomass)(IBR, see §63.14(b)) or equivalent
	e. Determine moisture content of the fuel type	ASTM D3173-02 (IBR, see §63.14(b)) or ASTM E871-82 (1998)(IBR, see §63.14(b)) or equivalent
	f. Measure mercury concentration in fuel sample.	ASTM D3684-01 (for coal)(IBR, see §63.14(b)) or SW-846-7471A (for solid samples) or SW-846-7470A (for liquid samples)
	g. Convert concentrations into units of "lb/MMBtu" of heat content.	

TABLE 7. Establishing Operating Limits

As stated in §63.7520, Boiler 8 shall comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
1. Particulate Matter	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1)Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a)You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests (b)Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control)	i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c)	(1)Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a)You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests (b)Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
				test run

TABLE 8. Demonstrating Continuous Compliance

As stated in §63.7540, Boiler 8 shall show continuous compliance with the emission limitations as follows:

If you must meet the following operating limits or work practice standards	You must demonstrate continuous compliance by
3. Wet Scrubber Pressure Drop and Liquid Flow Rate *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).
6. Precipitator Secondary Current and Voltage or Total Power Input *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §63.7530(c)
7. Fuel Pollutant Content *(For Mercury)*	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to §63.7540(a).

Compliance with the above operating limits and work practice standards demonstrate continuous compliance with the emission limits for PM, HCl, and Hg. A COMS for opacity is not required due to the wet cyclone scrubber. The CO emission limit (400 ppmvd @ 7% oxygen based on a 30-day rolling average) is set as a work practice standard for controlling emissions of organic HAPs. Continuous compliance with the CO limit is demonstrated by data collected with the required CEMS. Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 9. Reporting Requirements

As stated in §63.7550, Boiler 8 shall comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance Report	a. Information required in §63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	Semiannually according to the requirements in §63.7550(b).

You must submit a(n)	The report must contain	You must submit the report
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in §63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.