Golder Associates Inc.

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

Golder Associates

TRANSMITTAL LETTER

To: Mr. Jeff Koerner, P.E.
FDEP

Date: September 1, 2006
Project No.: 0537540/0537541-0100

RE... ED
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BUREAU OF AIR REGULATION

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Cc: Don Griffin, U.S. Sugar

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Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL USA 32653
Telephone (352) 336-5600
Fax (352) 336-6603
www.golder.com

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BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. Jeff Koerner, P.E., Air Permitting South

**RE: UNITED STATES SUGAR CORPORATION
CLEWISTON AND BRYANT MILLS
TITLE V RENEWAL APPLICATION
PROJECT NOS. 0510003-031-AC AND 0510003-032-AV
THIRD REQUEST FOR ADDITIONAL INFORMATION**

Dear Mr. Koerner:

United States Sugar Corporation (U.S. Sugar) has received the Florida Department of Environmental Protection's (FDEP) second request for additional information (RAI) dated November 11, 2005, regarding the Title V renewal application. Each of the FDEP's requests is answered below, in the same order as they appear in the RAI letter.

1. Please review "Attachment A – Summary of CAM Plans Proposed by Applicant" of this request for accuracy. The following questions refer to this attachment and the CAM Plans.

a. Explain why the proposed monitoring values were reduced by 90%.

Response: **As explained in the CAM Plan, under the Subsection titled "Justification" for each boiler, the 90 percent factor is based on the Boiler MACT rule (40 CFR 63, Subpart DDDDD). The Boiler MACT rule will take effect in September 2007 for each existing boiler (Boiler Nos. 1, 2, 4 and 7 at Clewiston; Boiler Nos. 1, 2, 3 and 5 at Bryant). The MACT requires that the minimum parameter value be set at 90 percent of the minimum test run value. When the Boiler MACT rule takes effect, it will supercede CAM, unless U.S. Sugar becomes exempt from the total selected metals (TSM) standard based on the health-based compliance alternative (HCBA), in which case the PM limit under Subpart DDDDD will not apply. In the interim, it is logical to make the CAM parameter limits equivalent to the Boiler MACT rule. If ultimately U.S. Sugar is exempt from the Subpart DDDDD PM limit, it is still logical to base CAM on the Subpart DDDDD requirements since these requirements meet the definition of CAM.**

b. Explain why some of the proposed indicator ranges are so much lower than the annual averages identified in the application. (i.e., Clewiston Boilers 1, 2 and 4, and Bryant Boilers 1 and 5. etc.)

Response: **Clewiston Boiler No. 1 – The annual average identified in the application is based on general knowledge of the scrubber operation. There is scrubbing liquid water flow rate data for this boiler recorded during the past compliance tests. The 2003 testing was performed with a recorded water flow rate of about 56 gpm. The normal water flow rate is approximately 300 gpm. The testing in November 2003 could be regarded as an outlier. U.S. Sugar would be willing to accept the parameter value limitation based on the remaining available data. Table B-1 from the CAM Plan has been updated to include the past season's test data. See revised CAM Plan (Attachment A). Based on the data, using 90 percent of the minimum test run water flow and pressure drop, the minimum parameter values would be 328 gpm (90 percent of 364 gpm), and 6.3 inches H_2O (90 percent of 7.0 inches H_2O).**

Clewiston Boiler No. 2 – The annual average identified in the application is based on general knowledge of the scrubber operation. There is scrubbing liquid water flow rate data for this boiler recorded during the past compliance tests. The 2003 and 2004 testing was performed with a recorded water flow rate of between 65 and 123 gpm. The normal water flow rate is approximately 300 gpm. The testing in 2003 and 2004 could be regarded as outliers. U.S. Sugar would be willing to accept the parameter value limitation based on the remaining available data. Table B-1 from the CAM Plan has been updated to include the past season's test data. Based on the data, using 90 percent of the minimum test run water flow and pressure drop, the minimum parameter values would be 319 gpm (90 percent of 354 gpm), and 6.3 inches H_2O (90 percent of 7.0 inches H_2O).

Clewiston Boiler No. 4 - The annual average identified in the application is based on general knowledge of the scrubber operation. As shown in Table B-1 of the CAM Plan, there is an extensive history of test data that shows the scrubber water flow during the compliance tests has ranged from 245 gpm to 623 gpm. The annual averages identified in the application of 375 gpm and 8 to 11inches H_2O are just that- averages, and do not represent the minimums. The extensive history of test data justifies the proposed parameter minimum values of 220 gpm and 7.6 inches H_2O, which are based on 90 percent of the minimum test run averages.

Bryant Boiler No. 1 - The annual average identified in the application is based on general knowledge of the scrubber operation. Table B-2 of the CAM Plan shows the scrubber water flow during the compliance tests has ranged from 220 gpm to 303 gpm, and the pressure drop from 6.0 to 9.5 inches H_2O. The annual averages identified in the application of 240 gpm and 8.8 inches H_2O are within these ranges, and do not represent the minimums. The extensive history of test data justifies the proposed parameter minimum values of 200 gpm and 4.8 inches H_2O, which are based on 90 percent of the minimum test run averages.

Bryant Boiler No. 5 - The annual average identified in the application is based on general knowledge of the scrubber operation. Table B-2 of the CAM Plan shows the scrubber water flow during the compliance tests has ranged from 850 gpm to 966 gpm, and the pressure drop from 7.0 to 13.5 inches H_2O across each scrubber. The annual averages identified in the application of 400 gpm for water flow actually represent the water flow to each of the two scrubbers. The pressure drop of 11.5 inches H_2O does represent a good average. The extensive history of test data justifies the proposed parameter minimum values of 765 gpm and 7.2 inches H_2O, across each scrubber, which are based on 90 percent of the minimum test run averages.

c. Provide a technical justification for reducing the monitoring frequency from 4 times/hour for units with potential emissions greater than 100 tons per year (i.e., units operate under relatively steady operational loads; control equipment parameters are "dialed-in" and only reset for large swings in operation; proposed monitoring frequency will be increased from current monitoring frequency; unit has shown relatively low emissions for proposed indicator range; etc.). Explain any difficulties with continuously monitoring the total secondary power input to the ESP for Clewiston Boiler 7.

Response: **Beginning September 13, 2007, Boiler Nos. 1, 2, 4 and 7 at Clewiston, and Boiler Nos. 1, 2, 3 and 5 at Bryant will be subject to the Boiler MACT standards. This rule will require monitoring scrubber parameters at least every 15-minutes of operation, and parameter values will be based upon a 3-hour averaging time. For these boilers, it is requested that the current Title V monitoring requirements be retained, for approximately the next 1-year period, at which time the Boiler MACT requirements will govern. This time period will allow U.S. Sugar to make the necessary upgrades to the monitoring and recording systems. In essence, U.S. Sugar is requesting that CAM be determined to be meeting the Boiler MACT requirements beginning September 2007.**

In the event that any of the boilers become exempt from the Boiler MACT requirements for TSM (PM is the surrogate), and therefore CAM becomes applicable, U.S. Sugar will comply with the proposed CAM plan beginning September 2007.

U.S. Sugar already measures total secondary power input to the Boiler No. 7 ESP.

d. Clewiston Boiler 7 and 8 have wet cyclones as pre-control devices prior to the ESP. Although pressure drop was an important parameter in selecting and designing the wet cyclones, it is not a controllable parameter and is dependent on boiler load/flue gas exhaust rate. However, the water flow rate to the wet cyclones is a controllable parameter and monitoring for a minimum flow rate will ensure proper operation. Please identify the minimum operational flow rate (CAM indicator range) for these devices.

Response: **The wet cyclone for Boiler No. 7 is installed to protect the ID fan from excessive wear due to sand in the flue gas. The cyclone is not necessary**

for air pollution control, as the electrostatic precipitator (ESP) itself is adequate to meet the PM emission standard. When Boiler No. 7 was originally designed and constructed, the cyclone was not included. It was added only after the ID fan experienced premature failure. Since the cyclone is not a control device, but is inherent process equipment, it is not subject to CAM.

Boiler No. 8 is not subject to CAM since it is subject to the Boiler MACT rule. In addition, U.S. Sugar recently made changes to the Boiler No. 8 wet cyclones to eliminate water to the cyclones (other than sluice water to remove collected material from the cyclones). This was implemented in order to eliminate moisture carryover to the ESP.

e. Although Boiler 8 is subject to a NESHAP promulgated after 11/15/90, it is necessary to establish a CAM Plan for the PM BACT standard. However, these monitoring requirements can be the same because the emissions standards and averaging period are identical. Please comment.

Response: **The PM emission limit for Boiler No. 8 has been revised to be equivalent to the Boiler MACT rule (0.025 lb/MMBtu). This was implemented through air construction permit no. 0510003-030-AC/PSD-FL-333B. It is our understanding that, when the permit limit is identical to the MACT standard, CAM does not apply.**

f. As was previously discussed, the Department identified Clewiston Boilers 4, 7 and 8 as possibly being subject to CAM Plan requirements for SO2 emissions because these units have a specific SO2 emissions standard. Also as discussed, the Department reviewed SO2 emissions data and control options for the Clewiston Boilers (some wet controls) and the Okeelanta Cogeneration Boilers (dry controls). Based on our conversation and available information, the following is a summary of this review:

"For the Clewiston Mill, bagasse typically contains 0.08% to 0.24% with an average of approximately 0.1% sulfur by weight on a dry basis. Based on a heating value of 7200 Btu per dry lb of bagasse, this is equivalent to estimated uncontrolled emissions of approximately 0.22 to 0.66 lb SO2 per MMBtu. However, stack test data for these units show actual SO2 emissions ranging from 0.01 to 0.06 lb/MMBtu. This represents estimated reductions ranging from 40% to 90%.

The sugar industry typically uses surface water from ponds for wet scrubber and wet cyclone water. The applicant indicates that the typical pH of the pond water is 6.8. No chemicals are added to treat and control the pH levels of the scrubber water, which is used and then discharged back into the pond. According to the industry, the mechanism providing the reduction is adsorption of the SO2 onto ash particles generated from bagasse combustion, which is then removed by the particulate matter control device.

To evaluate this mechanism, data from the Okeelanta Cogeneration Boilers were reviewed. These units are spreader-stoker boilers similar in size to the Clewiston Boilers (760 MMBtu per hour) and fire roughly a 50%-50% blend of bagasse and wood chips as the primary fuel. However, water is not used in the particulate control device. Instead, particulate matter is removed with dry multi-clones followed by a dry electrostatic precipitator (ESP). For the

Okeelanta Mill, the important parameters are:

- Bagasse: 3600 Btu/lb, wet; 50% moisture; and an average sulfur content of 0.03% by weight
- Wood Chips: 4500 Btu/lb, wet; 40% moisture; and an average sulfur content of 0.07% by weight

Assuming a 50%-50% biomass blend by weight provides a fuel blend with an average heating value of 7350 MMBtu/lb and an average sulfur content of 0.05% sulfur by weight. This is equivalent to an uncontrolled emission rate of approximately 0.135 lb SO2 per MMBtu. However, the cogeneration boilers are equipped with monitors to continuously measure and record SO2 emissions. Based on CEMS data collected in 2000 for the cogeneration boilers, the average annual SO2 emission rate for these units was approximately 0.03 lb/MMBtu. This represents an estimated reduction of approximately 78%, which tends to validate that the SO2 removal mechanism as adsorption onto ash particles with removal by the particulate matter control device.

This information supports the contention that SO2 emissions are not being removed as a result of the "wet" scrubbing process. Nevertheless, the conclusion is that a properly functioning particulate matter control device is necessary to achieve the SO2 emission standards. Therefore, the Department intends to establish the same CAM monitoring program as identified for particulate matter for Clewiston Boilers 4, 7 and 8."

Please correct any inaccuracies and comment.

Response: **We agree with your assessment, except for the conclusion that a properly functioning PM control device is necessary for SO_2 removal. The SO_2 in the flue gas absorbs onto the alkaline fly ash and is removed from the flue gas by this mechanism. It is therefore not available to be emitted as SO_2, regardless of the fate of the PM itself. Therefore, we contend here is no "control device" for SO_2 emissions, and therefore CAM should not apply.**

g. For the granular carbon regenerative furnace (GCRF), Permit No. PSD-FL-272 specified a particulate matter emission standard of 0.7 lb/hour and a design control efficiency of 97%. Based on these parameters, the uncontrolled emission rate would be 102 tons/year. The permit specifies that the venturi scrubber shall be designed for a pressure drop of between 20 to 30 inches of water column and the wet tray scrubber shall be designed for a pressure drop of between 3 to 5 inches of water column. The permit requires these parameters to be monitored once per 8-hour shift. Please provide a CAM Plan for this control device. What is the "capacity" of this unit?

Response: **Based on the original design information for the GCRF (see Attachment B), the uncontrolled PM emissions were stated as 23 to 26 lb/hr. Based on 8,760 hr/yr operation, and using the higher uncontrolled emission rate, this yields an annual uncontrolled PM emission rate 114 TPY. Therefore, a CAM plan is being provided. The capacity of this unit is specified in terms of "40,000 lb/day product design rate" (granular carbon regenerated), as per the BSP letter dated March 6, 1997.**

2. Based on the revisions to NSPS Subpart Kb, do you want to consolidate all fuel storage tanks into a single emissions unit to simplify reporting for the Annual Operating Report? If so, please identify the tanks, identification numbers, storage volume, and materials stored.

   Response: **U.S. Sugar agrees with the suggestion. The information for the tanks is provided below.**

   - **100,000 gallon tank for low sulfur diesel for boilers;**
   - **200,000 gallon tank for low sulfur diesel for boilers; and**
   - **6,000 gallon tank for low sulfur diesel for carbon furnace that is fed from the boiler tanks.**

3. White Sugar Dryer 2 (EU-029) has not yet conducted a satisfactory compliance test. Do you want to include this unit in the Title V renewal or proceed without it? If included, please submit a compliance plan for conducting the test and submitting the test report. (Once satisfied, the requirements of the compliance plan will become obsolete.)

   Response: **Please proceed with the Title V permit renewal without this emission unit. Several rounds of PM testing have been completed on the White Sugar Dryer #2, and a permit application has been submitted to revise the allowable PM emission rate. Once the revised permitting has been concluded, U.S. Sugar will submit a Title V revision application.**

4. The PSD permit for Boiler 8 was recently modified (Project 0510003-032-AC) and updated for the NESHAP revisions. Please submit only the revised Title application pages for this unit.

   Response: **The revision for Boiler No. 8 which incorporated the Boiler MACT requirements was permit no. 0510003-030-AC/PSD-FL-333B. The revised Title V application pages are provided in Attachment C. This also includes the revisions to the cyclone dust collection system authorized by permit no. 0510003-035-AC, since this construction has been completed.**

5. The Department's South District Office issued Permit No. 0510003-033-AC to install a new lime silo. If constructed, please submit the revised Title V application pages for this new unit. If not yet constructed, you may submit the revised Title V application pages for this new unit with a compliance plan. For minor units such as this, the compliance plan would likely cover any notification and initial testing requirements. (Once satisfied, the requirements of the compliance plan will become obsolete.)

   Response: **This permit was actually for a limestone silo. Actual construction has been completed, but the initial testing has not been conducted due to the very infrequent deliveries of limestone at the Molasses Plant. In regards to the Title V permit, we believe this emissions unit can be incorporated into the Title V permit as an unregulated unit, in the same manner as several of the other minor baghouse sources are now specified. Revised application pages for the "unregulated" emissions units are provided in**

Attachment C, and the testing has been incorporated into the updated Compliance Plan.

6. The Bureau of Air Regulation recently issued Permit No. 0510003-034-AC to install the railcar loading/unloading/storage system at the refinery. You may submit the revised Title V application pages for this new unit with a compliance plan. The permit requires only an opacity test and the submittal of the test report. (Once satisfied, the requirements of the compliance plan will become obsolete.)

   Response: **This permit was actually for a lime unloading and storage system. Actual construction has been completed, but the system has not yet been placed into operation, and initial testing has not been conducted. In regards to the Title V permit, we believe this emissions unit can be incorporated into the Title V permit as an unregulated unit, in the same manner as several of the other minor baghouse sources are now specified. Title V application pages for the emissions unit are provided in Attachment C, and the testing has been incorporated into the updated Compliance Plan.**

7. The Bureau of Air Regulation recently issued Draft Permit No. 0510003-035-AC to install a dry cyclone dust collector for Boiler 8. The only requirement is a notification of completion of construction, which would be listed as the compliance plan and become obsolete once submitted. Please submit only the revised application pages for the proposed dry cyclone dust collector for Boiler 8.

   Response: **The installation of a grit collector has been completed. The change is accompanied by the elimination of water to the cyclones (other than sluice water to remove collected material from the cyclones). The revised Title V application pages are provided in Attachment C.**

8. You have recently submitted a request to EPA Region 4 to remove the NESAHP requirement to monitor pressure drop across the wet cyclones. Do you want to include this request as part of the Title V renewal project or proceed without these revisions?

   Response: **It is our understanding that EPA is allowing the FDEP to make the determination regarding this request. Therefore, we request FDEP to incorporate this request into an air construction permit and into the Title V permit.**

9. On May 19, 2006, we received your request to revise the original permit that modified the oil firing systems for Boilers 1 and 2. The Department intends to issue a revised permit shortly based on your request. The revision must be included in the Title V renewal project because all construction and testing is now complete. Please submit only the revised Title V application pages for these units.

   Response: **The requested pages of the Title V application form are attached. We have also included Boiler No. 4 since this boiler is now part of the request.**

10. You had previously indicated you would request a revision of the bagasse handling system regarding the installation of dust collectors as well as a revision to increase the maximum steam production rate for Boiler 8. Do you plan to submit this request shortly and include it as part of the Title V renewal project or proceed without these revisions?

    Response: **This request was submitted to the FDEP in mid-June 2006. We are not incorporating the revisions to Boiler No. 8 into the Title V renewal application at this time. However, we are requesting that the bagasse dust collectors be eliminated from the Title V permit, and the revised pages in Attachment C reflect this.**

11. Please review the previously submitted compliance plan and update as necessary.

    Response: **The compliance plan has been revised and is included in Attachment C.**

U.S. Sugar is currently constructing a new cooling tower to support its new evaporator process equipment. The Department requested that U.S. Sugar estimate the PM emissions from the cooling tower. The emission estimates are presented in Attachment D. The estimates are based on the manufacturer's design data for the cooling tower, as well as the expected maximum total dissolved solids concentration of the circulating water. As shown, the PM emissions are estimated at 3.3 tons per year, and the PM_{10} emissions at 2.4 tons per year. This renders the cooling tower as an insignificant source for Title V permitting purposes.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call me at (352)336-5600.

If you have any questions regarding this matter, please call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

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

DB/all

cc: Mr. Don Griffin, U.S. Sugar Corporation
Mr. Peter Briggs, U.S. Sugar Corporation
Mr. Ron Blackburn, SD Office
Mr. James Stormer, PBCHD

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ATTACHMENT A

REVISED CAM PLAN

COMPLIANCE ASSURANCE MONITORING PLAN
(CAM PLAN)
UNITED STATES SUGAR CORPORATION
CLEWISTON AND BRYANT MILLS

Prepared For:
United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, FL 33440

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

August 2006

0537540

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1.0 CAM APPLICABILITY ANALYSIS

1.1 CAM Rule Applicability Definition

On October 18, 2004, and September 12, 2001, the Florida Department of Environmental Protection (FDEP) issued Title V Air Operation Permit Nos. 0510003-017-AV and 0990061-006-AV to United States Sugar Corporation (U.S. Sugar) for the operation of the Clewiston and Bryant Mills, respectively. The Clewiston Mill permit expires on November 29, 2005, and the Bryant Mill permit expires on December 15, 2005. In order to renew the permits, a renewal application incorporating both the Clewiston and Bryant mills was submitted to the FDEP on June 1, 2005.

As part of the Title V renewal application, a Compliance Assurance Monitoring (CAM) Plan must be submitted as required by regulations adopted in Title 40, Part 64 of the Code of Federal Regulations (40 CFR 64). This regulation has been incorporated by reference in Rule 62-204.800, Florida Administrative Code (F.A.C.), and implemented in Rule 62-213.440, F.A.C.

CAM plans are required for all Title V permitted emissions units using control devices to meet federally enforceable emission limits or standards and that have pre-control emissions greater than "major" source thresholds. The term "major" is defined in the Title V regulations (40 CFR 70), but applied on a source-by-source basis. For most non-hazardous pollutants, the major source threshold is 100 tons per year (TPY). For hazardous air pollutants (HAPs), the threshold is 10 TPY for an individual HAP and 25 TPY for total HAPs combined.

The CAM rules contain specific exemptions for the applicability of CAM. Specifically exempted from CAM are emission limitations or standards promulgated under the following: Stratospheric Ozone Regulations contained in 40 CFR 82; the Acid Rain Program contained in 40 CFR 72; or those that are part of an emissions cap included in the Title V Permit. Also exempt are emission limitations or standards proposed after November 15, 1990, under the following: New Source Performance Standards (NSPS) contained in 40 CFR 60; and National Emission Standards for Hazardous Air Pollutants (NESHAPs) promulgated in 40 CFR 63. These limitations and standards have monitoring requirements equivalent to CAM included as part of the standard.

Inherent process equipment (IPE), or equipment that may have the effect of controlling emissions but is installed for the primary purpose of product recovery or raw material recovery, is also exempt from

CAM (40 CFR 64.1). In addition, CAM does not apply to any emission limit or standard for which the Title V permit specifies a continuous compliance determination method [40 CFR 64.2(b)(1)(vi)], provided that the method does not include an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device.

1.2 Applicability of CAM to Emissions Units

A review of emission units at the U.S. Sugar Clewiston and Bryant Mills was conducted to determine the applicability of the CAM rule. This evaluation was conducted for each emissions unit and regulated pollutant. First, the existence of a "control device" as defined by the CAM rule was determined on a source-by-source basis for each pollutant. Those emissions units without control devices were eliminated from further consideration. The remaining emissions units were then evaluated on a pollutant-by-pollutant basis to determine if a control device was used to meet a federally enforceable emission limit or standard.

Each pollutant without a federally enforceable emission limit or standard, emitted from a given emissions unit, was eliminated from further consideration. Uncontrolled annual emissions were then determined for each remaining source-pollutant combination. If uncontrolled emissions for a pollutant emitted from a given emissions unit were below major source thresholds, as defined by the CAM rule, that pollutant was not further considered. Specific exemptions to the applicability of the CAM rule were also considered in this evaluation.

A summary of the results of this evaluation process is presented in Table 1-1. Each pollutant-specific emissions unit at the U.S. Sugar mills, and its applicability to CAM, is described in the following sections.

1.2.1 Clewiston Boiler No. 1 (EU 001)

Boiler No. 1 is a vibrating-grate boiler that is fired by carbonaceous fuel (bagasse) and No. 2 fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 1 has a maximum capacity of 245,000 pounds per hour (lb/hr) steam and a maximum heat input rate of 495 million British thermal units per hour (MMBtu/hr) while burning carbonaceous fuel alone or in mixture with No. 2 fuel oil. The design maximum heat input due to No. 2 fuel oil alone is 130 MMBtu/hr, corresponding to a maximum of 963 gallons per hour (gph) of distillate oil. Fuel oil can include facility-generated "on-spec" used oil. No more than 6,000,000 gallons of distillate oil can be fired during any consecutive

12-month period in Boiler Nos. 1, 2, and 4 combined. This boiler may also burn petroleum contaminated soils up to 2 percent by weight of the bagasse feed rate and a maximum of 500 cubic yards per season.

Boiler No. 1 has federally enforceable emission limits for particulate matter (PM) and sulfur dioxide (SO_2). Boiler No. 1 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 1. Since there is no control device controlling SO_2 emissions from Boiler No. 1, a CAM plan for SO_2 is not required.

1.2.2 Clewiston Boiler No. 2 (EU 002)

Boiler No. 2 is a vibrating grate boiler that is fired by carbonaceous fuel (bagasse) and No. 2 fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 2 has a maximum capacity of 215,000 lb/hr steam and a maximum heat input rate of 447 MMBtu/hr while burning carbonaceous fuel alone or in mixture with No. 2 fuel oil. The design maximum heat input due to No. 2 fuel oil alone is 130 MMBtu/hr, corresponding to a maximum of 963 gph of distillate oil. Fuel oil can include facility-generated "on-spec" used oil. No more than 6,000,000 gallons of distillate oil can be fired during any consecutive 12-month period in Boiler Nos. 1, 2, and 4 combined. This boiler may burn petroleum-contaminated soils up to 2 percent by weight of the bagasse feed rate and maximum 500 cubic yards per season.

Boiler No. 2 has federally enforceable emission limits for PM and SO_2. Boiler No. 2 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 2. Since there is no control device controlling SO_2 emissions from Boiler No. 2, a CAM plan for SO_2 is not required.

1.2.3 Clewiston Boiler No. 4 (EU 009)

Boiler No. 4 is a traveling-grate boiler manufactured by Foster Wheeler that is fired by carbonaceous fuel and No. 2 fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 4 has a maximum capacity of 300,000 lb/hr steam (1-hour maximum) and 285,000 lb/hr steam (24-hour average). The maximum heat input when firing bagasse alone is 633 MMBtu/hr (1-hour maximum) and 600 MMBtu/hr (24-hour average). The unit has two multi-stage combustion low-nitrogen oxide (NO_x) fuel oil burners. The maximum heat input due to No. 2 fuel oil firing is 326 MMBtu/hr, corresponding to 2,417 gph of distillate oil. No more than 6,000,000 gallons of distillate oil can be fired during any consecutive 12-month period in Boiler Nos. 1, 2, and 4 combined.

Boiler No. 4 has federally enforceable emission limits for PM, SO_2, NO_x, carbon monoxide (CO), and volatile organic compounds (VOCs). Boiler No. 4 utilizes a Joy Turbulaire Impingement Scrubber, Size 200, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 4. Since there is no control device controlling NO_x, SO_2, CO, or VOC emissions from Boiler No. 4, CAM plans for NO_x, SO_2, CO, and VOC are not required.

1.2.4 Clewiston Boiler No. 7 (EU 014)

Boiler No. 7 is a spreader-stoker vibrating-grate boiler that is fired by carbonaceous fuel (bagasse) and distillate fuel oil (Grade Nos. 1 and 2). Boiler No. 7 has a maximum capacity of 385,000 lb/hr steam (1-hour maximum) and 350,000 lb/hr steam (24-hour average). The maximum heat input rate is 812 MMBtu/hr (1-hour maximum) and 738 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to fuel oil alone is 326 MMBtu/hr (1-hour average), corresponding to 2,417 gph of distillate oil. No more than 4,500,000 gallons of distillate oil can be fired during any consecutive 12-month period.

Boiler No. 7 has federally enforceable emission limits for PM, particulate matter less than 10 microns in diameter (PM_{10}), NO_x, SO_2, CO, VOC, and sulfuric acid mist (SAM). Boiler No. 7 utilizes an electrostatic precipitator (ESP) to reduce PM/PM_{10} emissions. The wet sand separator (cyclone) removes sand to protect the induced draft fan and ESP and is not considered a control device. The ESP is the control device for PM emissions from Boiler No. 7. As shown in Table 1-1, uncontrolled PM/PM_{10} emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM/PM_{10}, a control device is used to comply with the PM/PM_{10} emission limit; and because uncontrolled PM/PM_{10} emissions are greater than 100 TPY, a CAM plan is required for

PM/PM_{10} for Boiler No. 7. Since there is no control device controlling NO_x, SO_2, CO, VOC, or SAM emissions from Boiler No. 7, CAM plans for these pollutants are not required.

1.2.5 Clewiston Boiler No. 8 (EU 028)

Boiler No. 8 is a membrane wall, balanced-draft stoker boiler fired with carbonaceous fuel and No. 2 distillate fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 8 has a maximum heat input rate of 1,030 MMBtu/hr based on a 1-hour maximum steam rate of 550,000 lb/hr for carbonaceous fuel firing. The maximum permitted 24-hour average heat input rate for firing carbonaceous fuel is 936 MMBtu/hr corresponding to 500,000 lb/hr steam. The maximum permitted heat input rate for firing No. 2 fuel oil is 562 MMBtu/hr. Fuel oil can include facility-generated on-specification used oil.

Boiler No. 8 has federally enforceable emission limits for PM/PM_{10}, NO_x, SO_2, CO, VOC, hydrochloric acid (HCl), mercury (Hg), and ammonia (NH_3). Boiler No. 8 utilizes three dry cyclone collectors followed by an ESP to control PM/PM_{10} emissions. The dry cyclones remove sand to protect the induced draft fan and ESP, and are therefore considered to be IPE.

Boiler No. 8 is subject to the federal NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. This NESHAP was promulgated on September 13, 2004, and applies to new boilers that have commenced construction after January 13, 2003. The Subpart DDDDD rules regulate PM emissions from new boilers. As a result, Boiler No. 8 is subject to a post-November 15, 1990, NESHAP for PM; and therefore, this emissions unit is not subject to CAM for PM.

NO_x emissions are controlled by a selective non-catalytic reduction (SNCR) system. As shown in Table 1-1, uncontrolled NO_x emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for NO_x, a control device is used to comply with the NO_x emission limit; and because uncontrolled NO_x emissions are greater than 100 TPY, a CAM plan is required for NO_x for Boiler No. 8.

There are no control devices on Boiler No. 8 for SO_2, CO, VOC, or NH_3. Therefore, CAM plans for these pollutants are not required.

There are no control devices for Hg and HCl emissions on Boiler No. 8. U.S. Sugar will demonstrate compliance with the Hg limit specified in 40 CFR 63, Subpart DDDDD, by performing fuel sampling and analysis or by performing stack testing. Sections 63.7545(e) and 63.9(h)(2)(ii) require the owner or operator of a new boiler to submit a Notification of Initial Compliance Status. According to the Hg fuel analysis results in the initial compliance report for U.S. Sugar, Hg emissions are below detection limit for bagasse, which is well below the maximum achievable control technology (MACT) limit. The initial compliance report also shows that HCl "controlled" emissions measured at the stack are approximately three times lower than the MACT limit when burning bagasse. In addition, HCl emissions measured at the inlet to the dry cyclones serving Boiler No. 8 are approximately 20 percent of the MACT limit. Therefore, Boiler No. 8 can achieve the MACT standard for HCl and Hg without a control device when burning bagasse.

For wood fuel, the HCl and Hg levels in the wood exceed the MACT limits. Stack testing for HCl and Hg were conducted in August 2006 while burning wood fuel. The HCl emissions were measured prior to the dry cyclones and ESP. The results of the testing are not yet available.

Since there are no control devices controlling HCl and Hg emissions from Boiler No. 8, CAM plans for these pollutants are not required.

1.2.6 Clewiston Sugar Processing Operations

The Sugar Processing Operations at the U.S. Sugar mill consist of multiple emissions units: VHP Sugar Dryer [Emission Unit (EU) 015], White Sugar Dryers Nos. 1 and 2 (EU 016 and EU 029); Granular Carbon Regeneration Furnace (GCRF) (EU 017); three Vacuum Systems (EU 018); three Conditioning Silos (EU 019); two Screening and Distribution Baghouses (EU 020); Alcohol Usage (EU 021); and a Packaging Baghouse (EU 022).

EU 021 (Alcohol Usage) has no control device, and therefore, is exempt from the CAM requirements.

Uncontrolled PM emission rates from the sugar refinery emission units are presented in Table 1-2. EUs 015 (VHP Sugar Dryer) and 016 (White Sugar Dryer No. 1) each have a baghouse, and EU 029 (White Sugar Dryer No. 2) has four cyclones followed by a wet scrubber. The uncontrolled PM emission estimates, based on dryer outlet grain loading and exhaust gas flow for the VHP Sugar Dryer and White Sugar Dryer No. 1 are approximately 50,000 TPY (shown in Table 1-2). This high emission rate shows that sugar dust recovery by an add-on control device would be necessary even without any air pollution control regulations. Therefore, the baghouses on the VHP Sugar Dryer and White Sugar Dryer No. 1 and the cyclones on the White Sugar Dryer No. 2 serve as IPE.

The White Sugar Dryer No. 2 (EU 029) wet scrubber has uncontrolled PM emissions, after the cyclones, of greater than 100 TPY; therefore, CAM is required for the wet scrubber.

EUs 017, 018, 019, 020, and 022 at the refinery each have a control device and a federally enforceable emission limit for PM. The emissions from EUs 018, 019, 020, and 022 are controlled with baghouses. There are a total of nine baghouses within these emissions units.

PM emissions from EU 017 (GCRF) are controlled with a wet venturi/impingement plate scrubber system, and VOC emissions are controlled with a direct-flame afterburner. Uncontrolled emissions of VOCs from the GCRF are less than 100 TPY; therefore, CAM is not required for VOC (see Tables 1-2 and 1-3). There is also no control device for SO_2 emissions from the GCRF; therefore, CAM is not required for SO_2.

Uncontrolled emissions of PM from the Vacuum System (EU 018) are more than 100 TPY with an estimated grain loading of 5 grains per dry standard cubic foot (gr/dscf) reaching each baghouse; therefore, CAM for PM is required for this unit (see Table 1-2).

PM emissions from the three Conditioning Silos (EU 019), Screening and Distribution System (EU 020), and Sugar Packaging System (EU 022) are controlled with baghouses. The baghouses control PM emissions from conveyor drop points, transfer points, bucket elevators, and other drop-type operations. Uncontrolled emissions of PM from each are less than 100 TPY; therefore, CAM is not required (see Table 1-2).

CAM applicability for the sugar refinery emission units is summarized in Table 1-1.

1.2.7 Bryant Boiler No. 1 (EU 001)

Boiler No. 1 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 1 may also burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 1 has a maximum capacity of 194,600 lb/hr (24-hour average) steam, and a maximum heat input rate of 385 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to No. 6 fuel oil alone is 189 MMBtu/hr (1,295 gph), and the maximum allowable quantity of fuel oil fired on each calendar day is limited to 80,000 gallons combined, for Bryant Boilers 1, 2, and 3. The maximum expected operation hours of 6,168 hours per year are based on October 1 to June 14 operation.

Boiler No. 1 has federally enforceable emission limits for PM, SO_2, NO_x, and VOC. Boiler No. 1 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit, and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 1. Since there is no control device controlling NO_x, SO_2, or VOC emissions from Boiler No. 1, CAM plans for these pollutants are not required.

1.2.8 Bryant Boiler No. 2 (EU 002)

Boiler No. 2 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 2 may also burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 2 has a maximum capacity of 194,600 lb/hr (24-hour average) steam and a maximum heat input rate of 385 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to No. 6 fuel oil alone is 189 MMBtu/hr (1,295 gph), and the maximum allowable quantity of fuel oil fired on each calendar day is limited to 80,000 gallons combined for Bryant Boilers 1, 2, and 3. The maximum expected operation hours of 6,168 hours per year are based on October 1 to June 14 operation.

Boiler No. 2 has federally enforceable emission limits for PM, SO_2, NO_x, and VOC. Boiler No. 2 utilizes two Joy Turbulaire Impingement Scrubbers, Size 40, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for

PM for Boiler No. 2. Since there is no control device controlling NO_x, SO_2, or VOC emissions from Boiler No. 2, CAM plans for these pollutants are not required.

1.2.9 Bryant Boiler No. 3 (EU 003)

Boiler No. 3 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 3 may also burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 3 has a maximum capacity of 194,600 lb/hr (24-hour average) steam, and a maximum heat input rate of 385 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to No. 6 fuel oil alone is 189 MMBtu/hr (1,295 gph), and the maximum allowable quantity of fuel oil fired on each calendar day is limited to 80,000 gallons combined, for Bryant Boilers 1, 2, and 3. The maximum expected operation hours of 6,168 hours per year are based on October 1 to June 14 operation.

Boiler No. 3 has federally enforceable emission limits for PM, SO_2, NO_x, and VOC. Boiler No. 3 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 3. Since there is no control device controlling NO_x, SO_2, or VOC emissions from Boiler No. 3, CAM plans for these pollutants are not required.

1.2.10 Bryant Boiler No. 5 (EU 005)

Boiler No. 5 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 5 may burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 5 has a maximum capacity of 342,384 lb/hr steam (1-hour maximum) and a maximum heat input rate of 671 MMBtu/hr (1-hour maximum). The maximum 24-hour heat input rate is 583 MMBtu/hr, with a maximum 24-hour steam rate of 297,482 lb/hr. The design maximum heat input due to No. 6 fuel oil alone is 215.6 MMBtu/hr, corresponding to 1,477 gph of fuel oil. No more than 400,000 gallons of fuel oil can be fired per crop season. The maximum operation hours are 4,572 hours per year, based on October 1 to June 14 operations.

Boiler No. 5 has federally enforceable emission limits for PM, SO_2, and NO_x. Boiler No. 5 utilizes two Joy Turbulaire Impingement Scrubbers, Size 100, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 5. Since there is no control device controlling NO_x or SO_2 emissions from Boiler No. 5, CAM plans for these pollutants are not required.

1.2.11 Bryant Diesel Generating Unit Nos. 1 and 2 (EU 007 and 008)

The Diesel Generating Unit Nos. 1 and 2 are two 1,000-kilowatts (kW) diesel electric generator sets that are typically used during the sugar off-season, corresponding to a maximum operating period of 1,500 hours per year. Unit No. 1 has a 2-cycle, 1,440 brake horsepower (bhp) engine, Model No. 16-567-B, and Unit No. 2 has a 1,525 bhp engine, Model No. 16-567-C. Both were manufactured by the Cleveland Diesel Engine Division of General Motors Corporation and were installed in 1985. The maximum heat input rate for Unit No. 1 is 12.6 MMBtu/hr and 13.3 MMBtu/hr for Unit No. 2, for a total maximum heat input of 25.9 MMBtu/hr.

The Diesel Generating Unit Nos. 1 and 2 have federally enforceable emission limits for SO_2 and NO_x. However, neither unit has a control device and is, therefore, not subject to CAM.

TABLE 1-1
CAM APPLICABILITY DETERMINATION FOR U.S. SUGAR CLEWISTON AND BRYANT MILLS

Emission Source	Title V EU ID	Control Equipment	Pollutants with Emission Limits	Uncontrolled Emission Rate (TPY)	CAM Plan Required? (Yes/No)	Comments
CLEWISTON						
Boiler No. 1	001	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
Boiler No. 2	002	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
Boiler No. 4	009	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
		None	NO_x	--	No	No control device.
		None	VOC	--	No	No control device.
		None	CO	--	No	No control device.
Boiler No. 7	014	ESP	PM/PM_{10}	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
		None	CO	--	No	No control device.
		None	SAM	--	No	No control device.
Boiler No. 8	028	ESP	PM/PM_{10}	--	No	Subject to post-1990 NESHAP (Subpart DDDDD).
		SNCR	NO_x	>100	**Yes**	NO_x uncontrolled emissions >100 TPY.
		None	CO	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
		None	HCl	--	No	No control device. Subject to post-1990 NESHAP (Subpart DDDDD).
		None	NH_3	--	No	No control device.
		None	Hg	--	No	No control device. Subject to post-1990 NESHAP (Subpart DDDDD).
VHP Sugar Dryer	015 (S-11)	Baghouse	PM	--	No	Baghouse serves as inherent process equipment.
White Sugar Dryer No. 1	016 (S-10)	Baghouse	PM	--	No	Baghouse serves as inherent process equipment.
Granular Carbon Regneration Furnace	017 (S-12)	Wet Scrubber	PM	99.1 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
		Afterburner	VOC	55.0 [a]	No	VOC uncontrolled emissions < 100 TPY.
<u>**Vacuum Systems**</u>						
Screening and Distribution Vacuum	018 (S-1)	Baghouse	PM	186 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
100-lb Bagging Vacuum	018 (S-2)	Baghouse	PM	164 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
5-lb Bagging Vacuum	018 (S-3)	Baghouse	PM	185 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
<u>**Conditioning Silos**</u>						
Conditioning Silo No. 2	019 (S-7)	Baghouse	PM	3 [a]	No	PM uncontrolled emissions <100 TPY.
Conditioning Silo No. 4	019 (S-8)	Baghouse	PM	3 [a]	No	PM uncontrolled emissions <100 TPY.
Conditioning Silo No. 6	019 (S-9)	Baghouse	PM	3 [a]	No	PM uncontrolled emissions <100 TPY.
<u>**Screening and Distribution**</u>						
Screening and Distribution #1	020 (S-5)	Baghouse	PM	22 [a]	No	PM uncontrolled emissions <100 TPY.
Screening and Distribution #2	020 (S-6)	Baghouse	PM	34 [a]	No	PM uncontrolled emissions <100 TPY.
<u>**Sugar Packaging**</u>						
Packaging Dust Collector	022 (S-4)	Baghouse	PM	25 [a]	No	PM uncontrolled emissions <100 TPY.
White Sugar Dryer No. 2	029 (S-13)	Wet Scrubber	PM	505 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
BRYANT						
Boiler No. 1	001	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
Boiler No. 2	002	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
Boiler No. 3	003	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
Boiler No. 5	005	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
Diesel Generating Unit No. 1	007	None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
Diesel Generating Unit No. 2	008	None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.

[a] Uncontrolled emissions shown in Tables 1-2 and 1-3.

TABLE 1-2
UNCONTROLLED EMISSIONS OF PM FROM THE SUGAR REFINERY SOURCES, U.S. SUGAR CORP., CLEWISTON

Source/Vent Name	EU No.	Source ID	Refined Sugar Throughput[a] (TPD)	Refined Sugar Throughput[a] (lb/hr)	Refined Sugar Throughput[a] (TPY)	Number of Drop Points	Exhaust Gas Flow (dscfm)	PM Uncontrolled Emission Factor	Particulate Matter (PM) Uncontrolled Emissions (lb/hr)	Particulate Matter (PM) Uncontrolled Emissions (TPY)[b]
V.H.P. Sugar Dryer/Baghouse	015	S-11	2,250	187,500	803,000	--	110,042	14 gr/dscf [c]	13,205	57,838
White Sugar Dryer No. 1/Baghouse	016	S-10	2,250	187,500	803,000	--	94,488	14 gr/dscf [c]	11,339	49,663
Granular Carbon Regeneration Furnace/Wet Scrubber	017	S-12	2,250	187,500	803,000	--	--	see footnote d	26 [d]	113.9
White Sugar Dryer No. 2/Cyclone(4)/Wet Scrubber	029	S-13	2,250	187,500	803,000	--	96,000	0.14 gr/dscf [g]	115.2	505
<u>Vacuum Systems</u>										
Screening and Distribution Vacuum/Baghouse	018	S-1	2,250	187,500	803,000	--	990	5 gr/dscf [e]	42.43	185.84
100 lb Bagging Vacuum System/Baghouse	018	S-2	2,000	166,667	803,000	--	872	5 gr/dscf [e]	37.37	163.69
5 lb Bagging Vacuum System/Baghouse	018	S-3	2,000	166,667	803,000	--	984	5 gr/dscf [e]	42.17	184.71
<u>Conditioning Silos</u>										
Conditioning Silo No. 2/Baghouse	019	S-7	2,250	187,500	803,000	1	2,641	0.0076 lb/ton [f]	0.71	3.12
Conditioning Silo No. 4/Baghouse	019	S-8	2,250	187,500	803,000	1	2,641	0.0076 lb/ton [f]	0.71	3.12
Conditioning Silo No. 6/Baghouse	019	S-9	2,250	187,500	803,000	1	2,641	0.0076 lb/ton [f]	0.71	3.12
<u>Screening and Distribution</u>										
Screening and Distribution Baghouse #1	020	S-5	2,250	187,500	803,000	7	2,668	0.0076 lb/ton [f]	4.99	21.85
Screening and Distribution Baghouse #2	020	S-6	2,250	187,500	803,000	11	8,735	0.0076 lb/ton [f]	7.84	34.33
<u>Sugar Packaging Baghouse</u>										
Packaging Dust Collector/Baghouse	022	S-4	2,000	166,667	730,000	9	9,589	0.0076 lb/ton [f]	5.70	24.97

[a] Based on amount of sugar produced by the fluidized bed drying system and loaded via the bulk shipment facility, such that the maximum daily loadout rate is limited to 2,250 TPD. The amount of refined sugar that could be processed through packaging operations is 2,000 TPD.
[b] Based on 8,760 hr/yr operation.
[c] Based on inlet loading to White Sugar Dryer No. 2 cyclone collectors. These dryers assumed to have the same outlet grain loading.
[d] Based on 26 lb/hr uncontrolled PM from design data and 8,760 hr/yr.
[e] Based on estimated grain loading prior to baghouse.
[f] Bulk load-out operations continuous drop emission factors are computed from AP-42 (USEPA, 1995) Section 13.2.4.
E (lb/ton) = k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 ; where U is assumed to be minimum value (1.3 mph) given in AP-42 due to the building enclosure.
M = Moisture Content = 0.25% for refined sugar (minimum AP-42 value).
k = 0.74 for PM.
[g] Grain loading after the cyclones, which are considered inherent process equipment.
Note: lb/hr = pounds per hour.
TPY = tons per year.

TABLE 1-3
UNCONTROLLED EMISSIONS OF VOC FROM THE SUGAR REFINERY SOURCES
U.S. SUGAR CORP., CLEWISTON

Source/Vent Name	EU No.	Source ID	Uncontrolled VOC Emissions (lb/hr)	Uncontrolled VOC Emissions (TPY) [b]
Granular Carbon Regeneration Furnace/Afterburner	017	S-12	12.50 [a]	54.75

[a] Based on an outlet loading of 1.0 lb/hr and a total VOC destruction efficiency of 92 percent.
[b] Based on operating at 8,760 hr/yr.

Note: lb/hr = pounds per hour.
TPY = tons per year.

2.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 1

2.1 Emissions Unit Identification

Clewiston Boiler No. 1—EU ID 001

2.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 1 has a PM emission limit of 0.25 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV) plus 0.1 lb/MMBtu for distillate oil [Rule 62-296.410(1)(b)2, F.A.C. and Permit No. 0510003-027-AC]. The equivalent potential emissions are 123.8 lb/hr and 542.0 TPY for carbonaceous fuel and 20.8 lb/hr and 23.6 TPY for distillate oil. The current VE limit is 30 percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit Nos. 0510003-017-AV and 0510003-027-AC, and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 1. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0510003-017-AV).

2.3 Control Technology Description

PM emissions from Boiler No. 1 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 6 to 12 inches of water (inches H_2O). The operating scrubber water inlet pressure to each scrubber is 60 to 130 pounds per square inch gauge (psig). The effectiveness of the wet scrubbers is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU1-I3).

2.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 1	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 6 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 328 gallons per minute (gpm). Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

2.5 Justification

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of

adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has historic test data to establish indicator values for pressure drop and water flow rate to the Boiler No. 1 wet scrubber. The test data correlating the parameters to the PM emission levels is presented in Figures 2-1 and 2-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 7 inches H_2O
	Minimum parameter value = 7 x 0.9 = 6 inches H_2O
Water Flow Rate:	Minimum test run value = 364 gpm
	Minimum parameter value = 364 x 0.9 = 328 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 1 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 2-1
PM vs. Water Flow
Clewiston Boiler No. 1

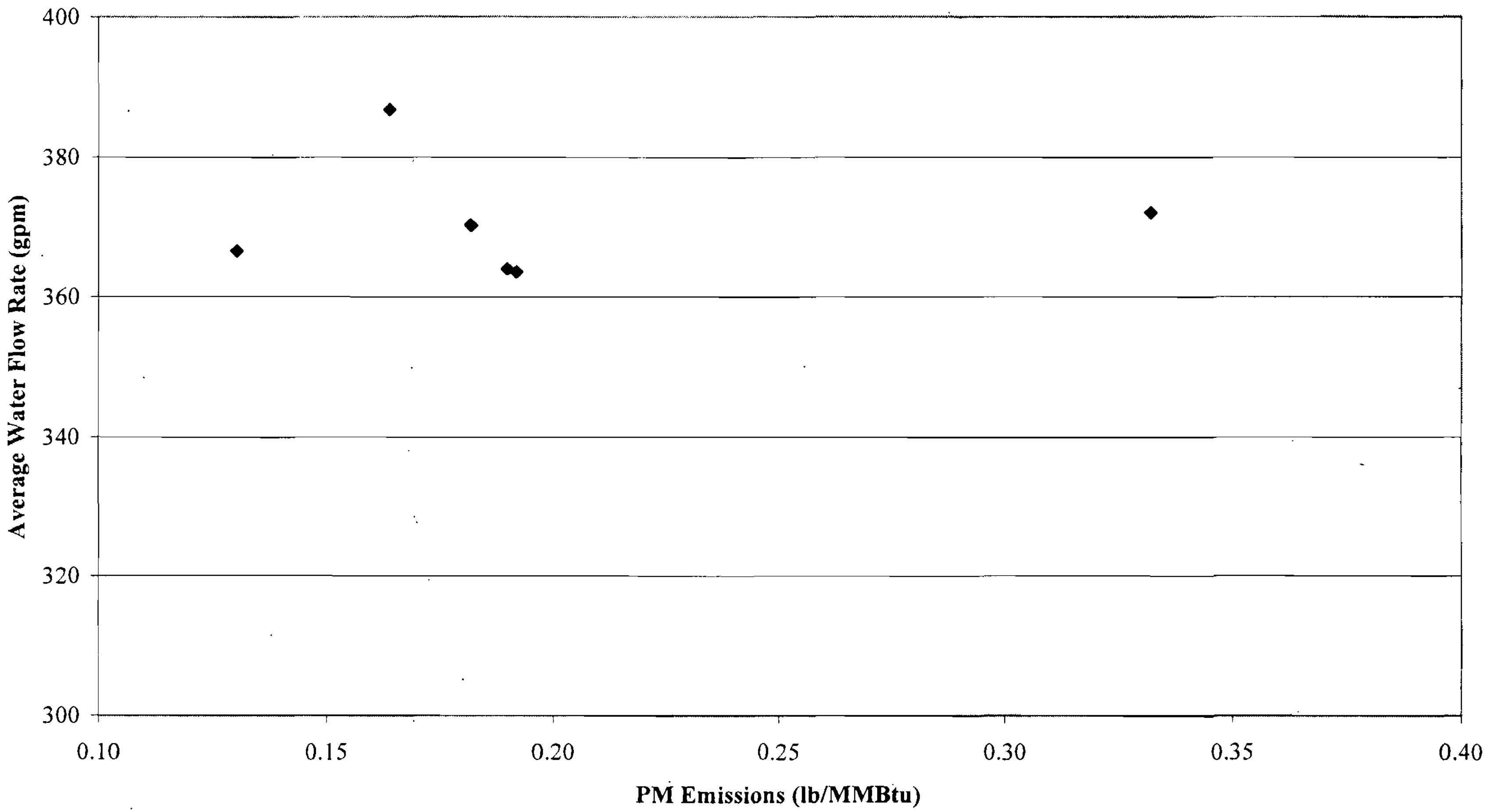
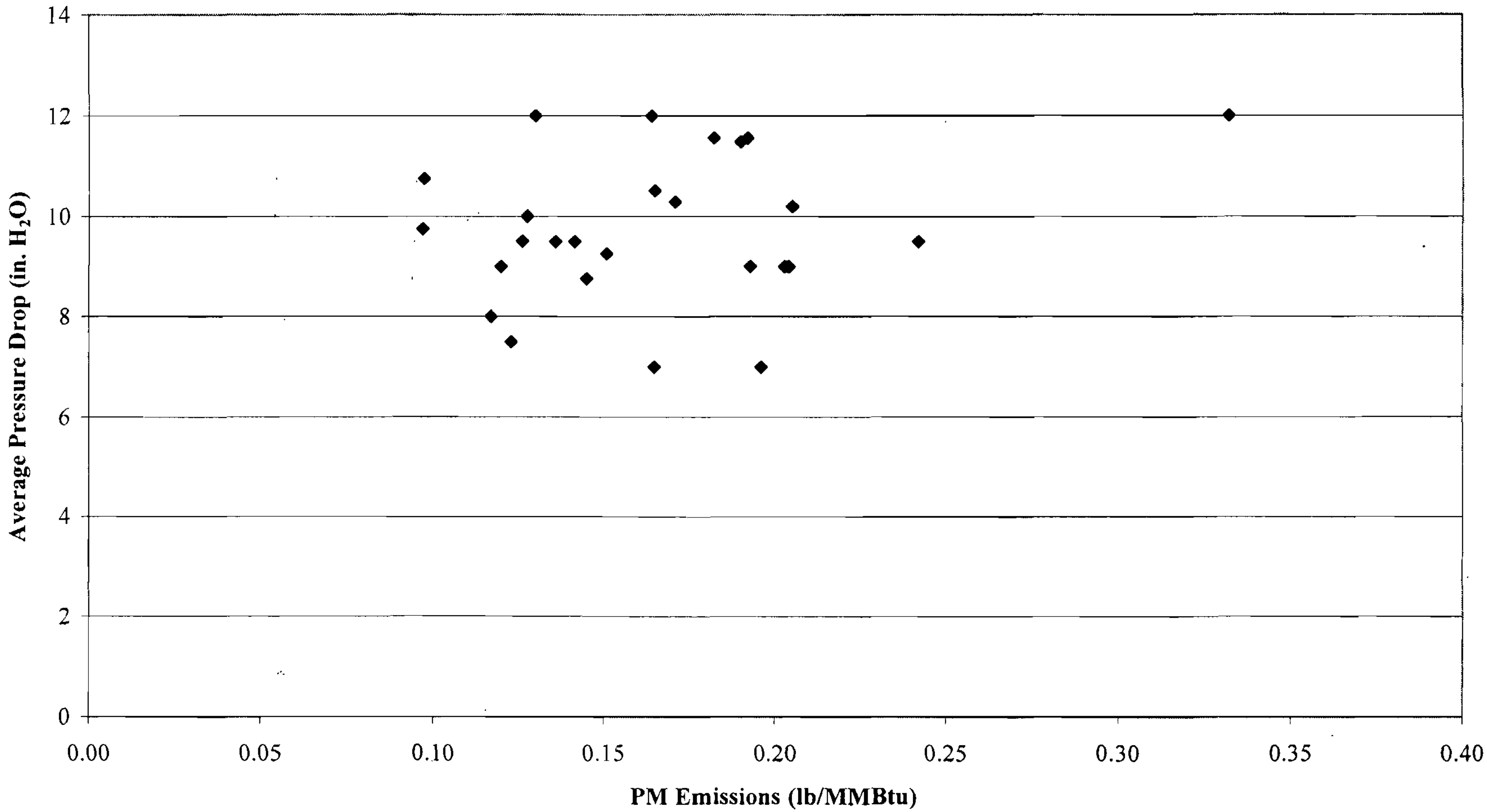


FIGURE 2-2
PM vs. Pressure Drop
Clewiston Boiler No. 1



3.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 2

3.1 Emissions Unit Identification

Clewiston Boiler No. 2—EU ID 002

3.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 2 has a PM emission limit of 0.25 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV) plus 0.1 lb/MMBtu for distillate oil [Rule 62-296.410(1)(b)2, F.A.C., and Permit No. 0510003-027-AC]. The equivalent potential emissions are 111.8 lb/hr and 490.0 TPY for carbonaceous fuel and 20.8 lb/hr and 23.6 TPY for distillate oil. The current VE limit is 30-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit Nos. 0510003-017-AV and 0510003-027-AC, and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 2. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0510003-017-AV).

3.3 Control Technology Description

PM emissions from Boiler No. 2 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 6 to 12 inches H_2O. The operating scrubber water inlet pressure is 60 to 130 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU2-I3).

3.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 2	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 5 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 319 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

3.5 Justification

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of

adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has historic test data to establish indicator values for pressure drop and water flow rate to the Boiler No. 2 wet scrubber. The test data correlating the parameters to the PM emission levels is presented in Figures 3-1 and 3-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 6 inches H_2O
	Minimum parameter value = 6 x 0.9 = 5 inches H_2O
Water Flow Rate:	Minimum test run value = 354 gpm
	Minimum parameter value = 354 x 0.9 = 319 gpm

Note that the pressure drop values of 3.0 in H_2O, recorded during the January 12, 1998 compliance test as shown in Appendix B, are considered to be outliers and were not used in determining the minimum pressure drop value.

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 2 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 3-1
PM vs. Water Flow
Clewiston Boiler No. 2

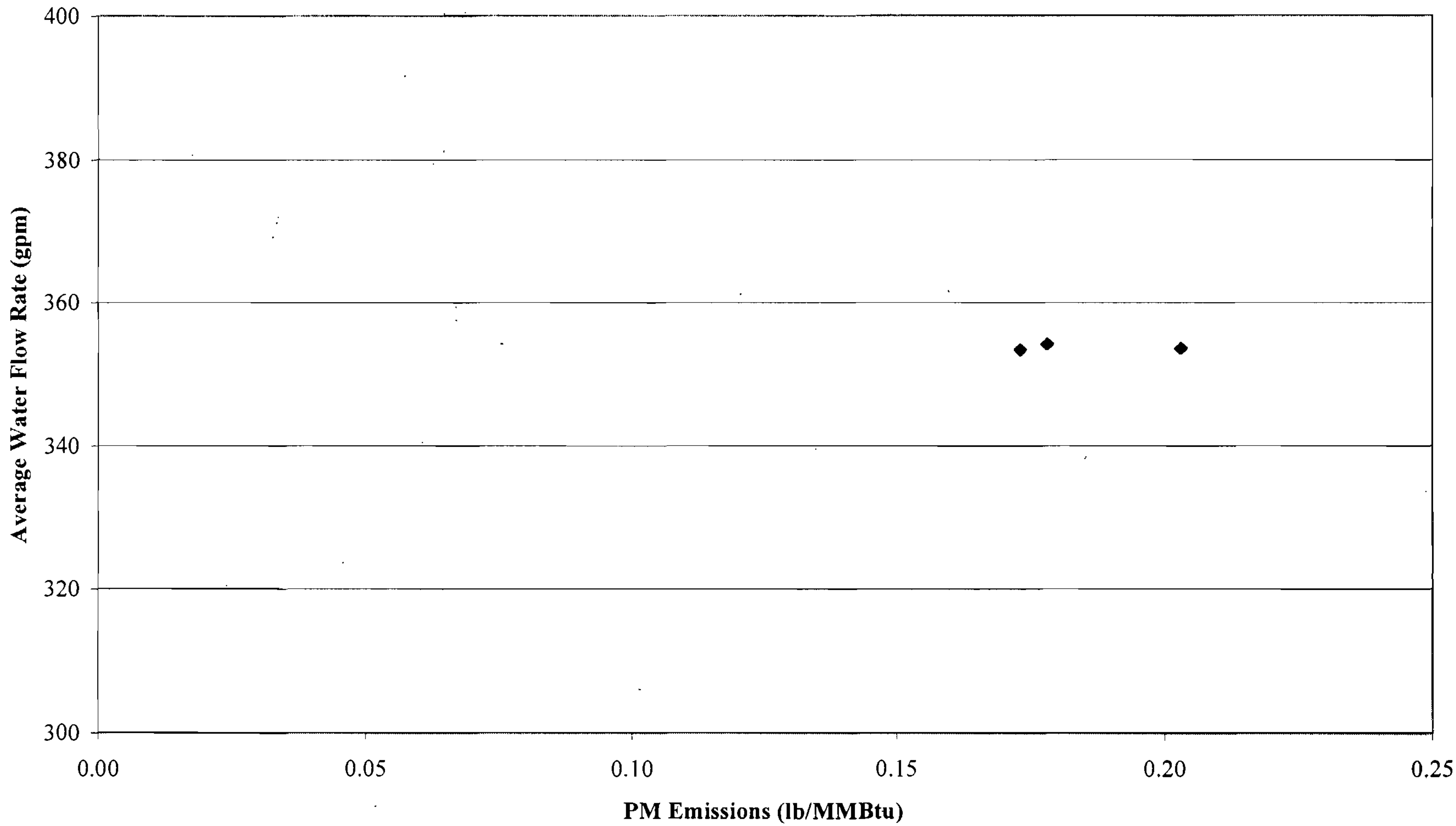
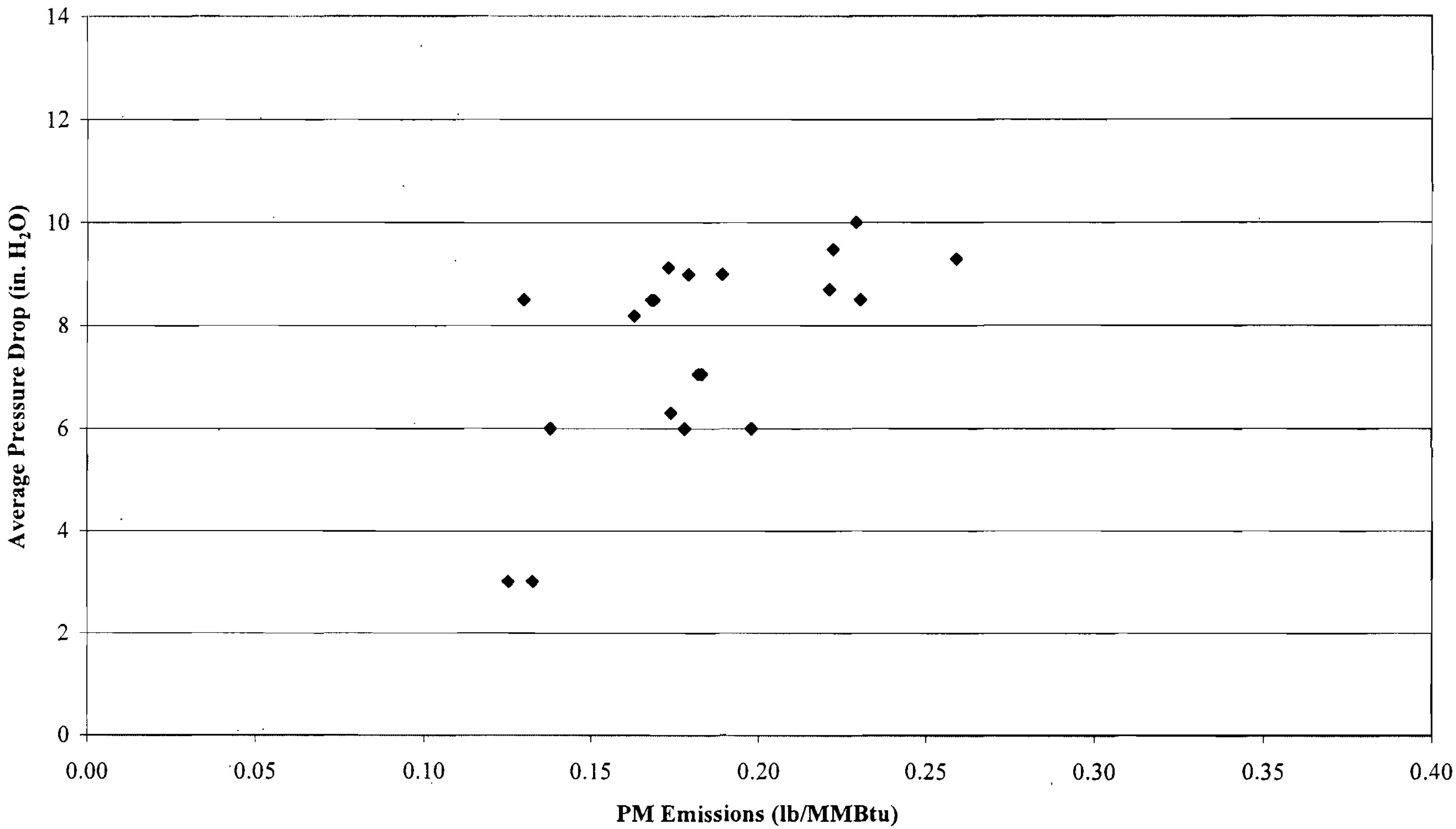


FIGURE 3-2
PM vs. Pressure Drop
Clewiston Boiler No. 2



4.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 4

4.1 Emissions Unit Identification

Clewiston Boiler No. 4—EU ID 009

4.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 4 has a PM emission limit of 0.15 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV), plus 0.1 lb/MMBtu for distillate oil [Rule 62-296.406, F.A.C. and Permit No. 0510003-018-AC]. The equivalent potential emissions are 95.0 lb/hr and 216.0 TPY for carbonaceous fuel and 32.6 lb/hr and 3.4 TPY for distillate oil. The current VE limit is 20-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour for carbonaceous fuel (Permit No. 0510003-017-AV), and 20-percent opacity, with an exception of up to 27-percent opacity for 6 minutes per hour for fuel burning (Permit No. 0510003-018-AC).

PM and VE compliance testing are required annually on Boiler No. 4. In addition, the total pressure drop across the scrubber, the scrubber water inlet pressure, and the scrubber water flow rate must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0510003-017-AV).

4.3 Control Technology Description

PM emissions from Boiler No. 4 are controlled by a Joy Turbulaire Impingement Scrubber, Size 200, Type D. The operating pressure drop across the scrubber is 8 to 23 inches H_2O. The operating scrubber water inlet pressure is 40 to 80 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU3-I3).

4.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 4	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 7.6 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 220 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches of water gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

4.5 Justification

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of

adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has historic test data to establish indicator values for pressure drop and water flow rate to the Boiler No. 4 wet scrubber. The test data correlating the parameters to the PM emission levels is presented in Figures 4-1 and 4-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 8.5 inches H_2O
	Minimum parameter value = 8.5 x 0.9 = 7.6 inches H_2O
Water Flow Rate:	Minimum test run value = 245 gpm
	Minimum parameter value = 245 x 0.9 = 220 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 4 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four (4) times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

According to the current Title V permit conditions, scrubber parameters should be recorded once every 3 hours. Because the actual emissions have been under the allowable emission rates since 1994 and the boiler data has been within the range of acceptable values for inlet pressure, pressure drop, and water flow rate, a recording frequency of once per 8-hour shift is proposed.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 4-1
PM vs. Water Flow
Clewiston Boiler No. 4

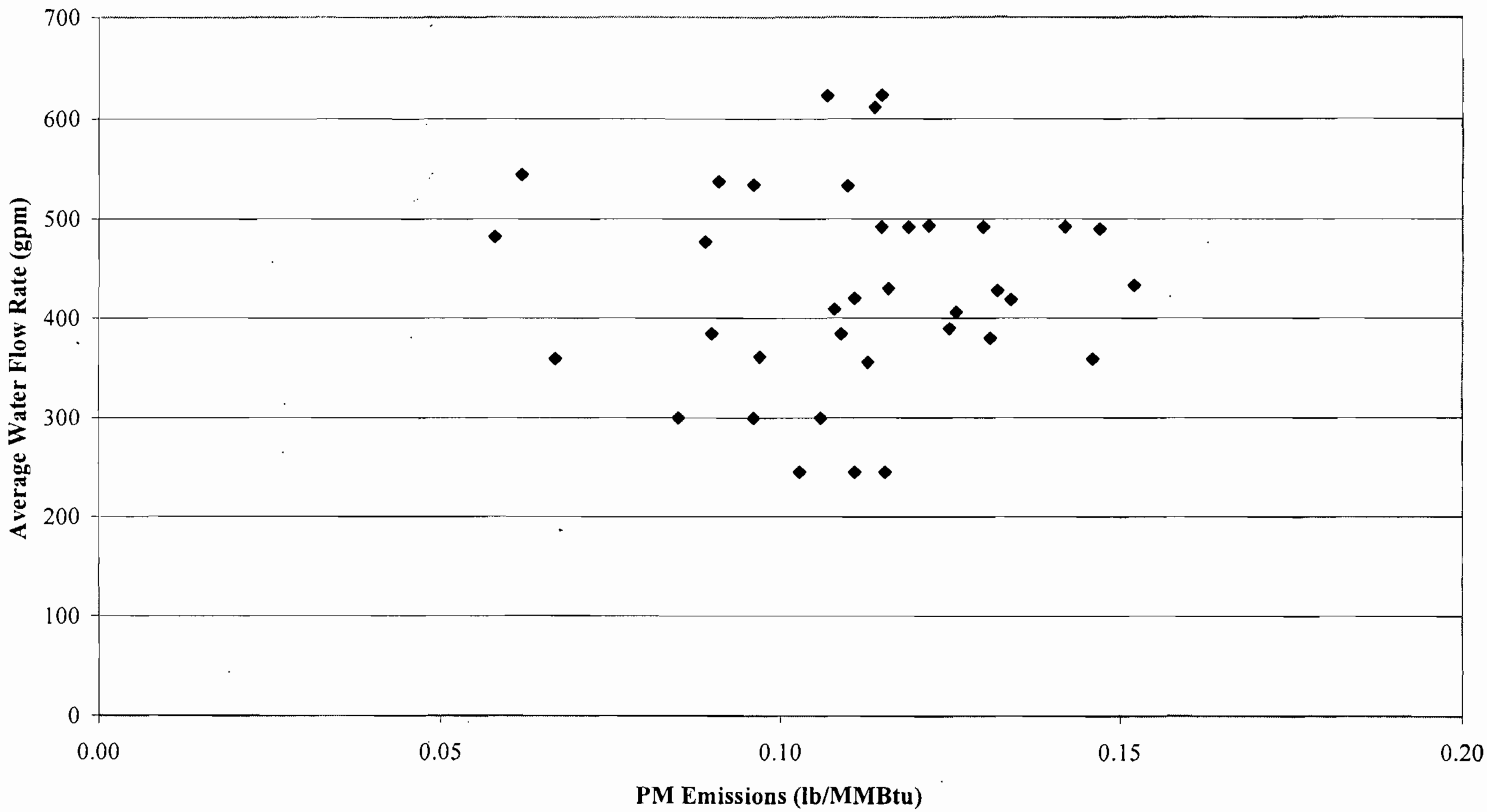
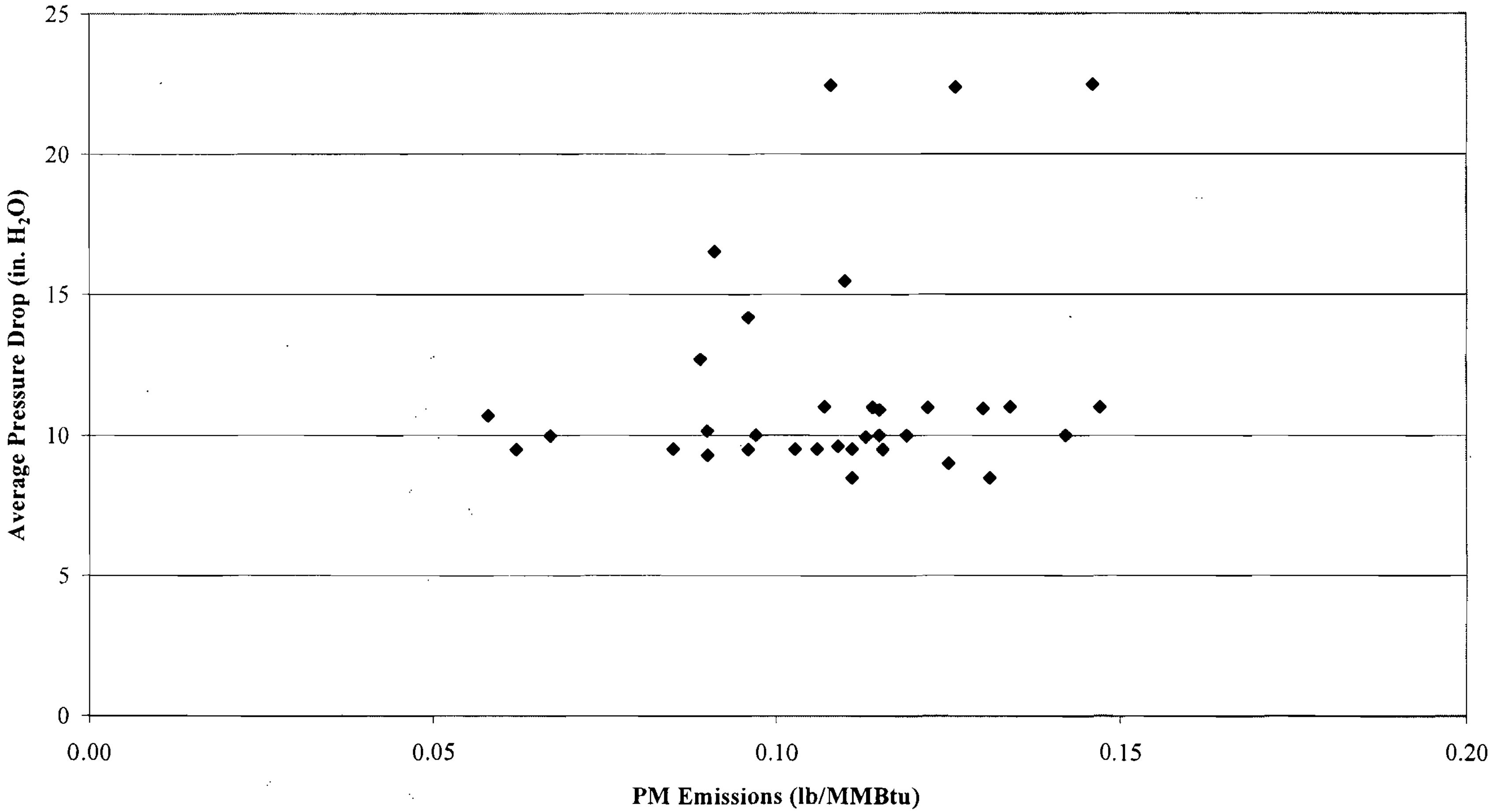


FIGURE 4-2
PM vs. Pressure Drop
Clewiston Boiler No. 4



5.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 7

5.1 Emissions Unit Identification

Clewiston Boiler No. 7—EU ID 014

5.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 7 has a PM/PM_{10} emission limit of 0.03 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV), plus 0.03 lb/MMBtu for No. 2 fuel oil [Rule 62-212.400(5), F.A.C. and Permit No. 0510003-018-AC]. The equivalent PM/PM_{10} potential emissions are 24.4 lb/hr and 97.0 TPY for carbonaceous fuel and 9.8 lb/hr and 9.1 TPY for No. 2 fuel oil. The current VE limit is 20 percent opacity, with an exception of up to 27 percent opacity for 2 minutes per hour when firing carbonaceous fuel [Rule 62-212.400(5), F.A.C. and Permit No. 0510003-017-AV] and 20 percent opacity, with an exception of up to 27 percent opacity for 6 minutes per hour when firing No. 2 fuel oil (Permit No. 0510003-018-AC).

PM/PM_{10} and VE compliance testing is required annually on Boiler No. 7. PM emissions are controlled by an ESP. The wet sand separator is an integral part of Boiler No. 7, since it exists to protect the induced draft fan and is, therefore, not considered a control device. The ESP is considered the PM control device for Boiler No. 7.

5.3 Control Technology Description

As described above, PM/PM_{10} emissions from Boiler No. 7 are controlled by an ESP. The wet sand separator removes sand to protect the induced draft fan and ESP, and is considered IPE.

The effectiveness of the ESP can be evaluated based on total power input to the ESP. The ESP has a total of three fields. Total power input can be determined by monitoring secondary voltage and secondary current to each field, calculating power input to each field, and summing the individual field values to obtain total power input. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU4-I3).

5.4 Monitoring Approach

The monitoring approach is based on monitoring total ESP secondary power input, which is calculated from the ESP secondary voltage and secondary current. The monitoring approach is summarized in the table below.

Boiler No. 7	Indicator No. 1
Indicator	Total Secondary Power Input
Measurement Approach	Total secondary power input to each field is calculated from the secondary current and voltage, which are monitored with an amp/volt meter.
Indicator Range	An excursion is defined as any total power input below 44 kW. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	Accuracy of the amp/volt meter is ±1 milliampere (mA) and ±1 kilovolt (kV).
Verification of Operational Status	NA
QA/QC Practices and Criteria	The amp/volt meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	ESP secondary current and secondary voltage are measured continuously and used to determine the total secondary power input.
Data Collection Procedures	Total power input calculated from voltage and current readings once per 8-hour shift.
Averaging Period	NA

5.5 Justification

Total secondary power input to the ESP is a recognized parameter for controlling PM/PM_{10} emissions, according to 40 CFR 63, Subpart DDDDD. Because the proposed indicator limit is based on test data from a single day, U.S. Sugar may conduct additional testing after the start of the new crop.

U.S. Sugar is choosing to use the historic test data at this time to establish an indicator value for total secondary power input to the Boiler No. 7 ESP. The test data correlating the parameter to the PM emission levels is presented in Figure 5-1. Supporting information is contained in Appendix B.

The proposed parameter minimum value is based on 90 percent of the minimum parameter value recorded during the test run, when compliance was demonstrated with the PM/PM_{10} limit. The calculation of the minimum parameter value is provided below:

ESP secondary power input:

Minimum test run value = 49.32 kW

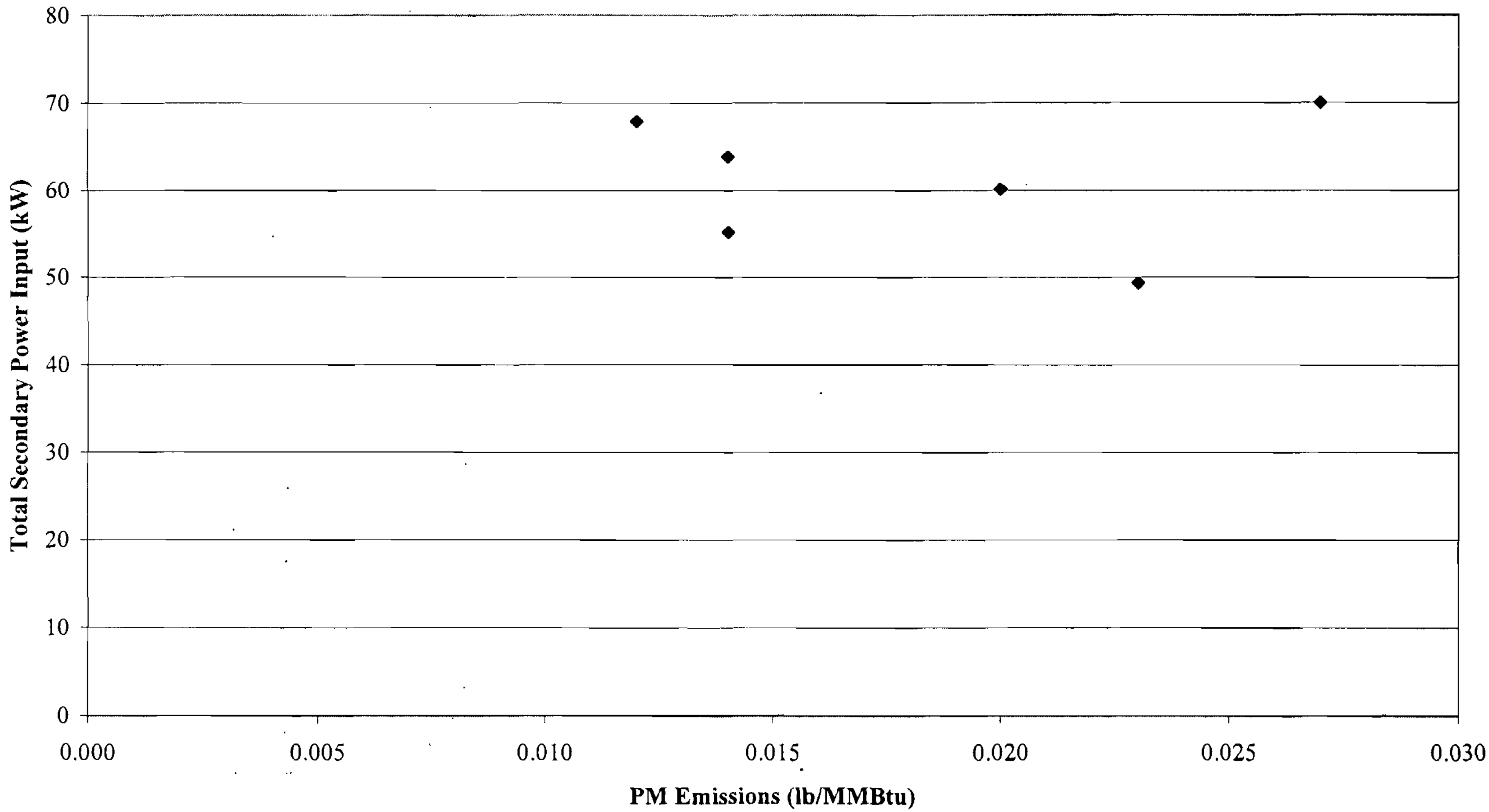
Minimum parameter value = 49.32 x 0.9 = 44 kW

ESP operating parameter values below this minimum parameter value will be indicative of abnormal operation of the control device. This methodology is consistent with the establishment of ESP operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 7 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. The CAM regulations also state that emission units with controlled emissions less than 100 TPY are subject to a reduced data collection frequency of at least once per day [40 CFR 64.3(b)(4)(iii)]. Because Boiler No. 7 has controlled emissions of less than 100 TPY, U.S. Sugar proposes a recording frequency of once per 8-hour shift.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 5-1
PM vs. Power
Clewiston Boiler No. 7



6.0 NITROGEN OXIDE EMISSIONS FROM CLEWISTON BOILER NO. 8

6.1 Emissions Unit Identification

Clewiston Boiler No. 8—EU ID 028

6.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 8 has a federally enforceable emission limit for NO_x. The NO_x emissions are limited to 0.14 lb/MMBtu (30-day rolling average) (Permit No. 0510003-024-AC/PSD-FL-333A). The equivalent potential emissions are 309 lb/hr and 473.7 TPY.

NO_x compliance testing is required annually on Boiler No. 8. The current permit requires emissions of CO and NO_x to be monitored and recorded by continuous emissions monitoring systems (CEMS) for compliance. According to 40 CFR 64.2 (b)(1)(vi), a CEMS satisfies CAM.

6.3 Control Technology Description

NO_x emissions from Boiler No. 8 are controlled by a SNCR system. The effectiveness of the control equipment is evaluated by a CEMS for NO_x. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU5-I3).

6.4 Monitoring Approach

The monitoring approach is based on the CEMS for NO_x and summarized in the table below:

Boiler No. 8	Indicator No. 1
Indicator	CEMS for NO_x.
Measurement Approach	The NO_x emission rate in "lb/MMBtu" is measured at least four times per hour at approximately 15-minute increments, using a CEMS for NO_x.
Indicator Range	An excursion is defined as any 30-day rolling average greater than 0.138 lb/MMBtu. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The CEMS for NO_x measures NO_x in the boiler stack gas.
Verification of Operational Status	NA
QA/QC Practices and Criteria	The CEMS for NO_x meets the requirements of 40 CFR 60, Appendix B, Performance Specification 2.
Monitoring Frequency	NO_x data is measured at least four times per hour at approximately 15-minute increments.
Data Collection Procedures	Hourly averages are calculated from readings at least once every successive 15-minute period.
Averaging Period	30-day rolling averages are calculated by averaging all 1-hour averages for each consecutive 30 boiler operating days.

6.5 Justification

The CEMS for NO_x provides a direct measurement of the effectiveness of the control system. U.S. Sugar is proposing to use continuous monitoring of the NO_x emissions to satisfy CAM requirements. Because the potential controlled NO_x emissions from Boiler No. 8 are greater than 100 TPY, NO_x emissions must be monitored at least once every 15 minutes. The CEMS meets this requirement.

The SNCR system on Boiler No. 8 generally maintains NO_x emissions at or just below 0.14 lb/MMBtu. However, fuel quality or other conditions may cause the NO_x emissions to go above 0.14 lb/MMBtu for short periods. If the 30-day rolling average NO_x emissions exceed 0.138 lb/MMBtu, this would indicate abnormal operation and constitute an excursion.

When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

7.0 PM EMISSIONS FROM THE WHITE SUGAR DRYER NO. 2

7.1 Emissions Unit Identification

White Sugar Dryer No. 2 -- EU ID No. 029

7.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

The White Sugar Dryer No. 2, which dries the sugar following centrifugation and precedes the conditioning silos, has an allowable PM emission limit of 0.005 gr/dscf. The equivalent potential emissions are 4.20 lb/hr and 18.38 TPY. The current VE limit is 10-percent opacity (Permit No. 0510003-026-AC/PSD-FL-346). Refined sugar production is limited to 803,000 TPY.

7.3 Control Technology Description

The White Sugar Dryer No. 2 system contains four (4) cyclone collectors followed by a wet scrubber. The cyclone collectors are considered to be IPE, since they collect sugar product from the dryer and recycle the sugar back to the process. Therefore, PM emissions are controlled by the wet scrubber. The cyclone collector is manufactured by Entoleter, LLC (Model 6600) and the wet scrubber is manufactured by Entoleter, LLC (Centrified Vortex Model 1500). A detailed description of the control equipment is included in the Title V renewal application, Attachment USS-EU6-I3, items l and m.

7.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber water recirculation rate and pressure drop across the wet scrubber. The monitoring approach is summarized in the table below:

White Sugar Dryer No. 2	Indicator No. 1	Indicator No. 2
Indicator	Scrubber water recirculation rate (gpm).	Pressure drop across the scrubber (inches H_2O).
Measurement Approach	Scrubber water recirculation rate is monitored with a magnetic flow meter (Rosemount 8732).	Pressure drop is monitored with a manometer or equivalent.
Indicator Range	Testing needed upon startup of new unit.	Testing needed upon startup of new unit.
Data Representativeness	The monitoring system will consist of a magnetic flow meter located on the scrubber recirculation line. The minimum accuracy of the device is ±5 percent of water flow.	The monitoring system will consist of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device will be ±0.5 inches H_2O gauge pressure.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The flow meter will be maintained in accordance with the manufacturer's recommendations.	The manometer will be maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Water recirculation rate will be monitored continuously.	Pressure drop will be monitored continuously
Data Collection Procedures	Data continuously recorded.	Data continuously recorded.
Averaging Period	Continuous data reduced to 3 hour block average.	Continuous data reduced to 3 hour block average.

7.5 Justification

Both pressure drop across the scrubber and water recirculation rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water recirculation rate is a measure of sufficient scrubbing liquid being supplied to the scrubber.

Because the White Sugar Dryer No. 2 is not yet constructed, U.S. Sugar is proposing to conduct testing at startup. The proposed parameter minimum values will be based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit.

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. An excursion will occur whenever any 3-hour block average is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

8.0 PM EMISSIONS FROM THE CLEWISTON SUGAR PROCESSING OPERATIONS

8.1 Emissions Unit Identification

Vacuum Systems – EU ID No. 018

8.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

The Vacuum Systems, which collect dust from the screening/distribution bins and packaging, have a PM emission limit of 0.18 lb/hr. The equivalent potential annual emissions are 0.84 TPY (Permit No. 0510003-010-AC/PSD-FL-272A).

FDEP has waived the PM compliance test requirements and has specified the alternative standard of 5-percent opacity (6-minute average) as the method for demonstrating compliance for this source.

8.3 Control Technology Description

PM emissions from the Vacuum Systems are controlled by three Hoffman (HPC-44120) baghouses. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU6-I3, items e, f and g).

8.4 Monitoring Approach

The monitoring approach is based on monitoring VE from the Clewiston Mill Sugar Processing Operation baghouses. The monitoring approach is summarized in the table below:

Sugar Processing Operations	Indicator No. 1
Indicator	Daily 1 minute VE observation for each baghouse.
Measurement Approach	VE are observed by an observer who is knowledgeable in VE, but who does not have to be a certified VE observer.
Indicator Range	An excursion is defined as any VE. If VE are observed, further investigation of the effectiveness of the baghouses will be performed.
Data Representativeness	VE observation according to EPA Method 22.
Verification of Operational Status	Operational status of each source will be verified prior to observing the VE.
QA/QC Practices and Criteria	VE will be determined based on 40 CFR 60, Appendix A – Method 22.
Monitoring Frequency	VE will be observed once a day for one (1) minute for each source.
Data Collection Procedures	Daily VE observations will be recorded in a log.
Averaging Period	NA

8.5 Justification

Uncontrolled PM emissions from the Vacuum Systems are greater than 100 TPY, but controlled PM emissions are less than 100 TPY. According to CAM regulations [40 CFR 64.3(b)(4)(iii)], the minimum frequency of data collection for emission-specific units emitting less than 100 TPY of controlled emissions is once per day. It is therefore proposed that a daily VE observation be conducted on each baghouse for a one-minute period, based on EPA Method 22 (40 CFR 60, Appendix A) for EU No. 018.

EPA Method 22 does not require the opacity of emissions be determined, and does not require the use of a certified VE reader. However, the observer, at a minimum, must be knowledgeable regarding influences on the visibility of emissions. U.S. Sugar will instruct its VE observers in the requirements and procedures for Method 22. If any VEs are observed, then further investigation will be performed to ensure the baghouses are operating correctly.

9.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 1

9.1 Emissions Unit Identification

Bryant Boiler No. 1 -- EU ID 001

9.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 1 has a PM emission limit of 0.3 lb/MMBtu for carbonaceous fuel [Rule 62 296.410(1)(b)2, F.A.C. and Permit No. 0990061-006-AV] plus 0.1 lb/MMBtu for No 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C. and Permit No. 0990061-006-AV]. The equivalent potential emissions are 115.5 lb/hr and 356.2 TPY for carbonaceous fuel and 18.9 lb/hr and 58.3 TPY for No. 6 fuel oil. The current VE limit is 30-percent opacity, with an exception of up to 40 percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 1. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0990061-006-AV).

9.3 Control Technology Description

PM emissions from Boiler No. 1 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 5 to 10 inches H_2O. The operating scrubber water inlet pressure to the scrubber is 48 to 60 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU7-I3).

9.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 1	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 4.8 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 200 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches of water gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

9.5 Justification

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of

adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and total water flow rate to the Boiler No. 1 wet scrubber. The test data correlating the parameters to the PM emission levels are presented in Figures 9-1 through 9-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 6.0 inches H_2O
	Minimum parameter value = 6.0 x 0.9 = 4.8 inches H_2O
Water Flow Rate:	Minimum test run value = 225 gpm
	Minimum parameter value = 225 x 0.9 = 202 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 1 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four (4) times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 9-1
PM vs. Water Flow
Bryant Boiler No. 1

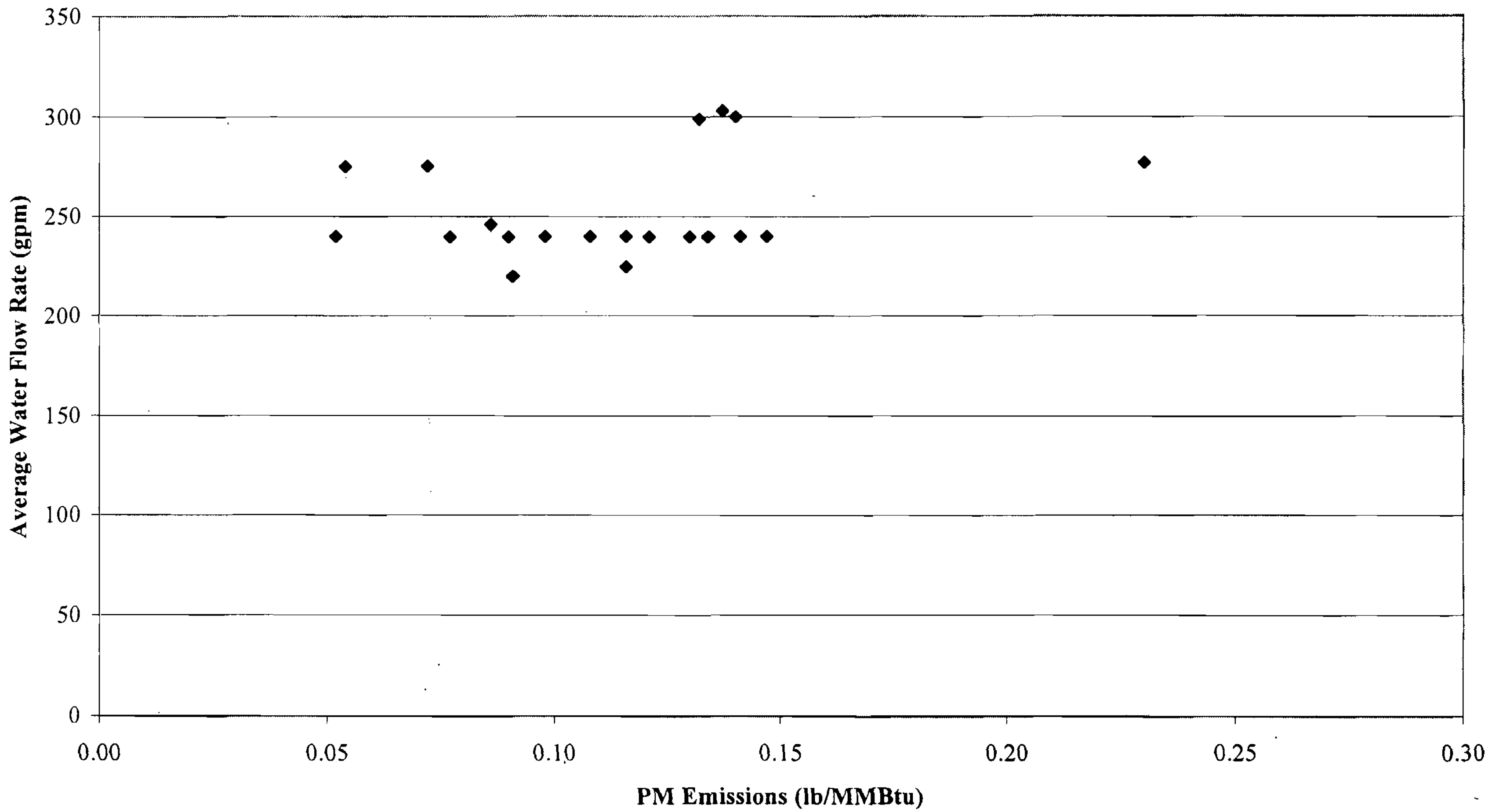
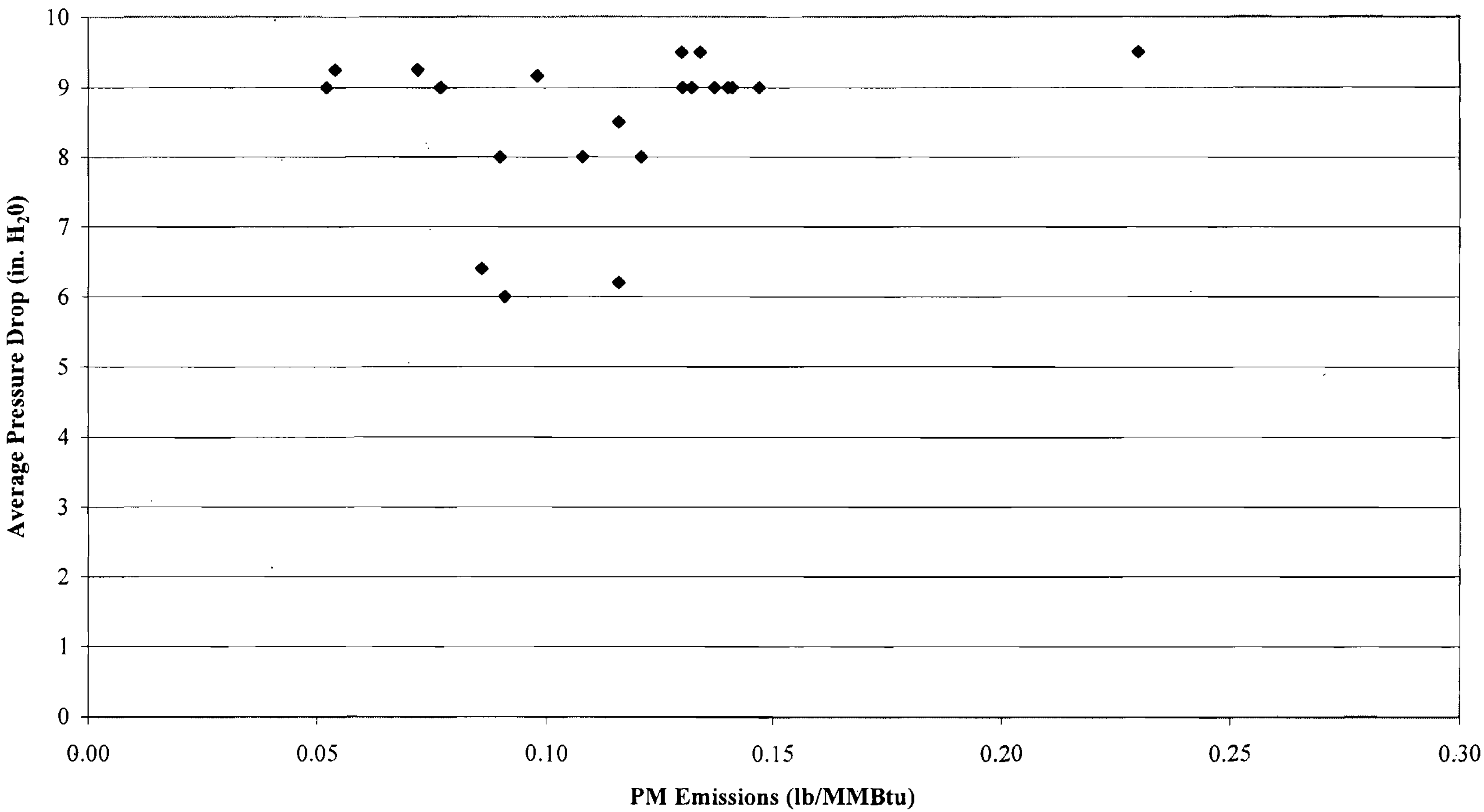


FIGURE 9-2
PM vs. Pressure Drop
Bryant Boiler No. 1



10.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 2

10.1 Emissions Unit Identification

Bryant Boiler No. 2 - EU ID 002

10.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 2 has a PM emission limit of 0.3 lb/MMBtu for carbonaceous fuel [Rule 62 296.410(1)(b)2, F.A.C., and Permit No. 0990061-006-AV] plus 0.1 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C. and Permit No. 0990061-006-AV]. The equivalent potential emissions are 115.5 lb/hr and 356.2 TPY for carbonaceous fuel and 18.9 lb/hr and 58.3 TPY for No. 6 fuel oil. The current VE limit is 30-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 2. In addition, the total pressure drop across each scrubber and the water inlet pressure at each scrubber must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration or repair (Permit No. 0990061-006-AV).

10.3 Control Technology Description

PM emissions from Boiler No. 2 are controlled by two Joy Turbulaire Impingement Scrubbers, Size 40, Type D. The operating pressure drop across each scrubber is 4 to 8 inches H_2O. The operating scrubber water inlet pressure to each scrubber is 48 to 60 psig. The effectiveness of the wet scrubbers is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU8-I3).

10.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 2	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across each scrubber.	Total water flow rate to each scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 3.6 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 200 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

10.5 Justification

Both pressure drop across each scrubber and water flow rate to each scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubbers.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubbers. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubbers. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has historic test data to establish indicator values for pressure drop and total water flow rate to the Boiler No. 2 wet scrubbers. The test data correlating the parameters to the PM emission levels are presented in Figures 10-1 through 10-3. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 4 inches H_2O
	Minimum parameter value = 4 x 0.9 = 3.6 inches H_2O
Water Flow Rate:	Minimum test run value = 225 gpm
	Minimum parameter value = 225 x 0.9 = 203 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 2 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 10-1
PM vs. Water Flow
Bryant Boiler No. 2

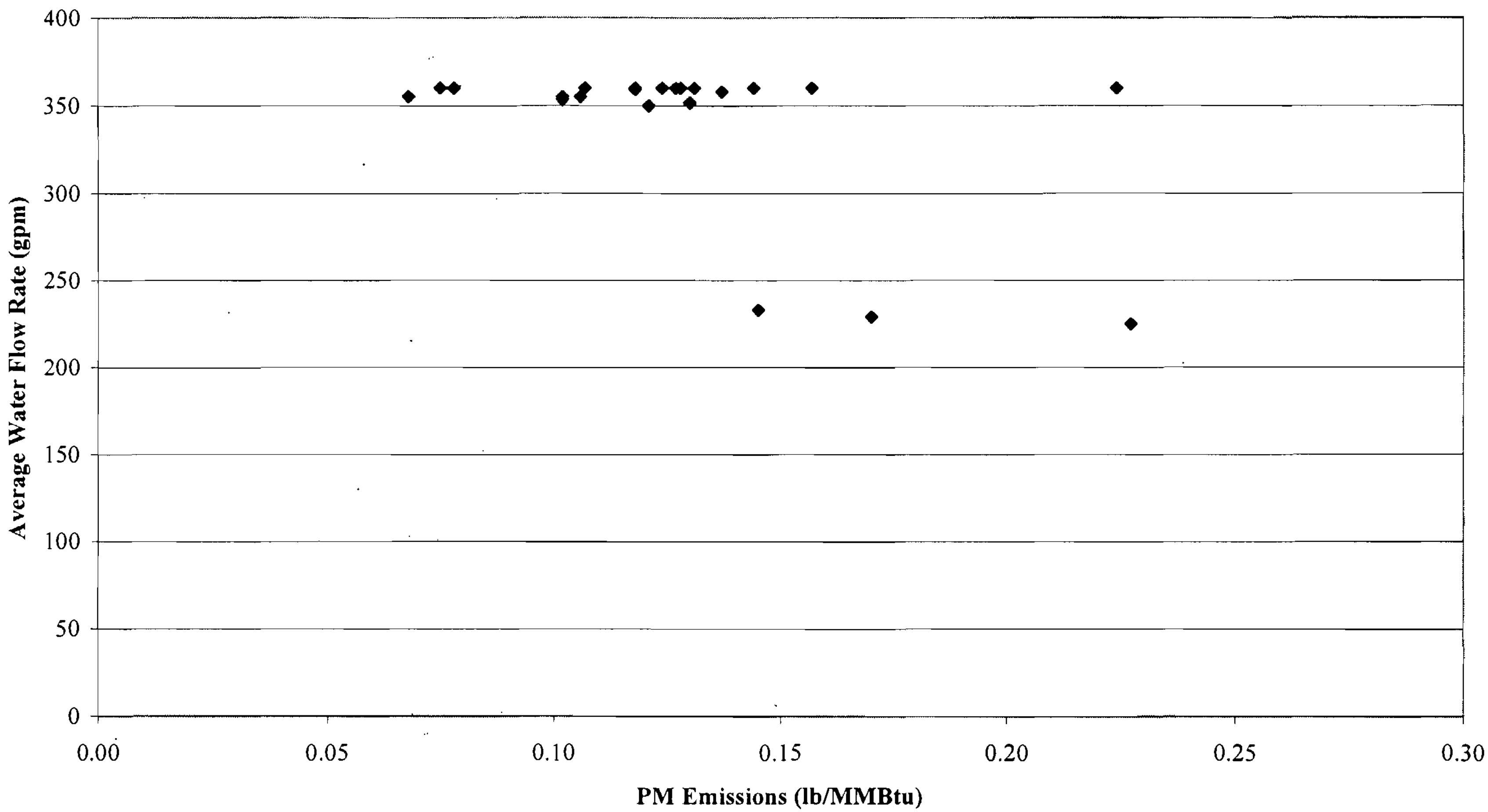


FIGURE 10-2
PM vs. Pressure Drop
Bryant Boiler No. 2 (North Scrubber)

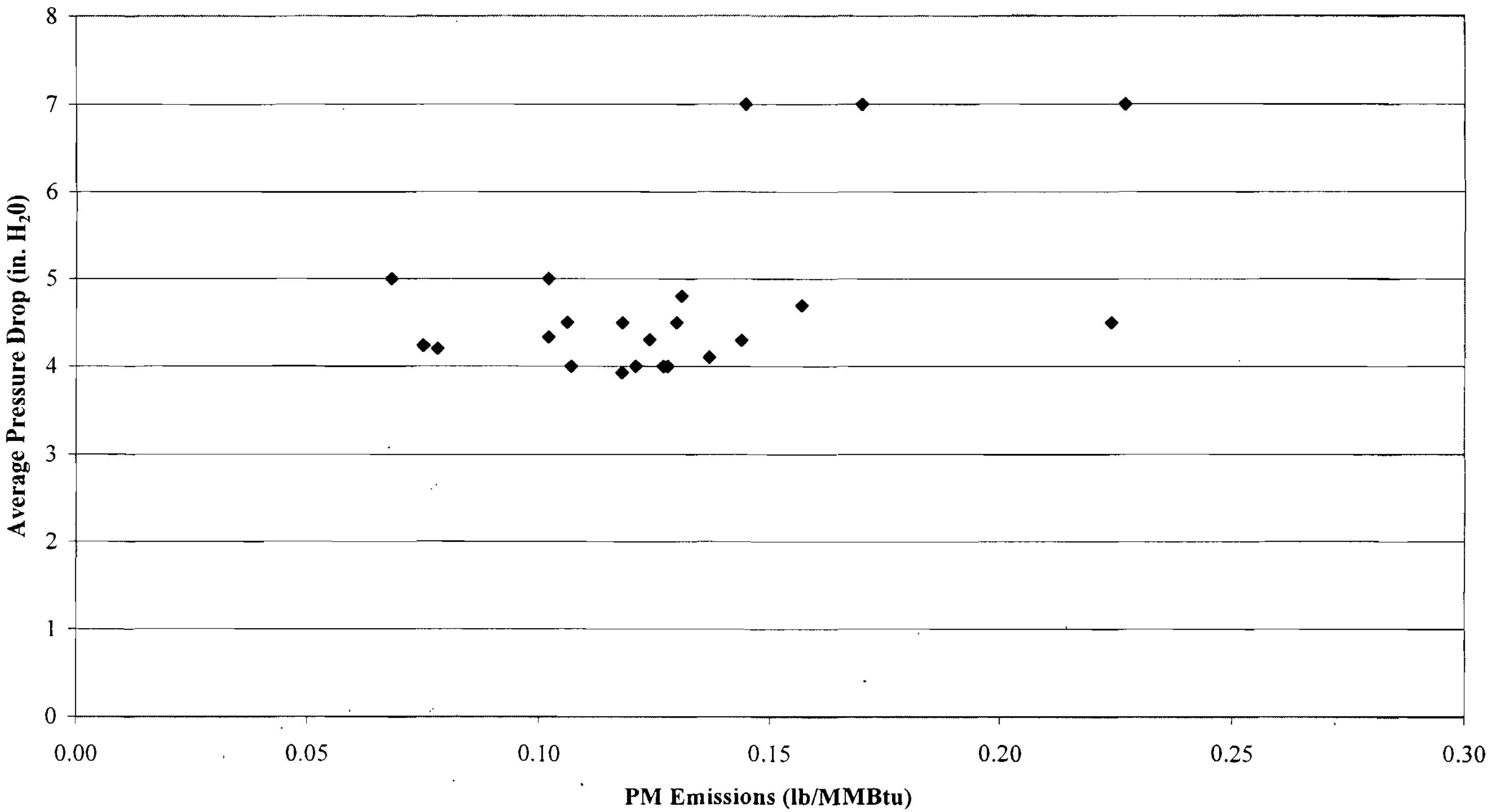
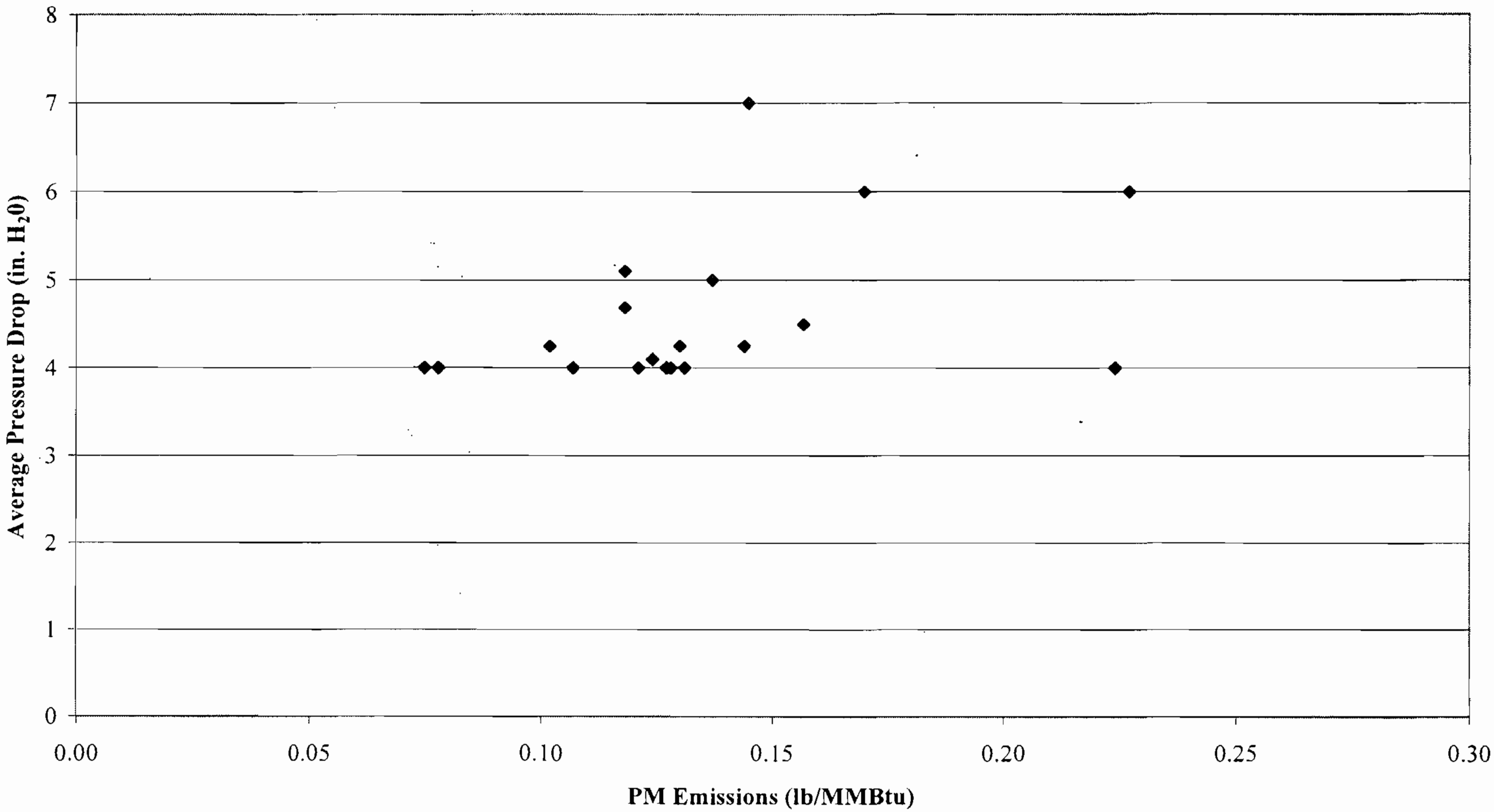


FIGURE 10-3
PM vs. Pressure Drop
Bryant Boiler No. 2 (South Scrubber)



11.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 3

11.1 Emissions Unit Identification

Bryant Boiler No. 3 - EU ID 003

11.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 3 has a PM emission limit of 0.3 lb/MMBtu for carbonaceous fuel [Rule 62 296.410(1)(b)2, F.A.C., and Permit No. 0990061-006-AV] plus 0.1 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C., and Permit No. 0990061-006-AV]. The equivalent potential emissions are 115.5 lb/hr and 356.2 TPY for carbonaceous fuel and 18.9 lb/hr and 58.3 TPY for No. 6 fuel oil. The current VE limit is 30-percent opacity, with an exception of up to 40 percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 3. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration or repair (Permit No. 0990061-006-AV).

11.3 Control Technology Description

PM emissions from Boiler No. 3 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 6 to 8 inches H_2O. The operating scrubber water inlet pressure is 48 to 60 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU9-I3).

11.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 3	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 5.4 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 216 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

11.5 Justification

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of

adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has historic test data to establish indicator values for pressure drop and total water flow rate to the Boiler No. 3 wet scrubber. The test data correlating the parameters to the PM emission levels are presented in Figures 11-1 and 11-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 6 inches H_2O
	Minimum parameter value = 6 x 0.9 = 5.4 inches H_2O
Water Flow Rate:	Minimum test run value = 240 gpm
	Minimum parameter value = 240 x 0.9 = 216 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 3 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 11-1
PM vs. Water Flow
Bryant Boiler No. 3

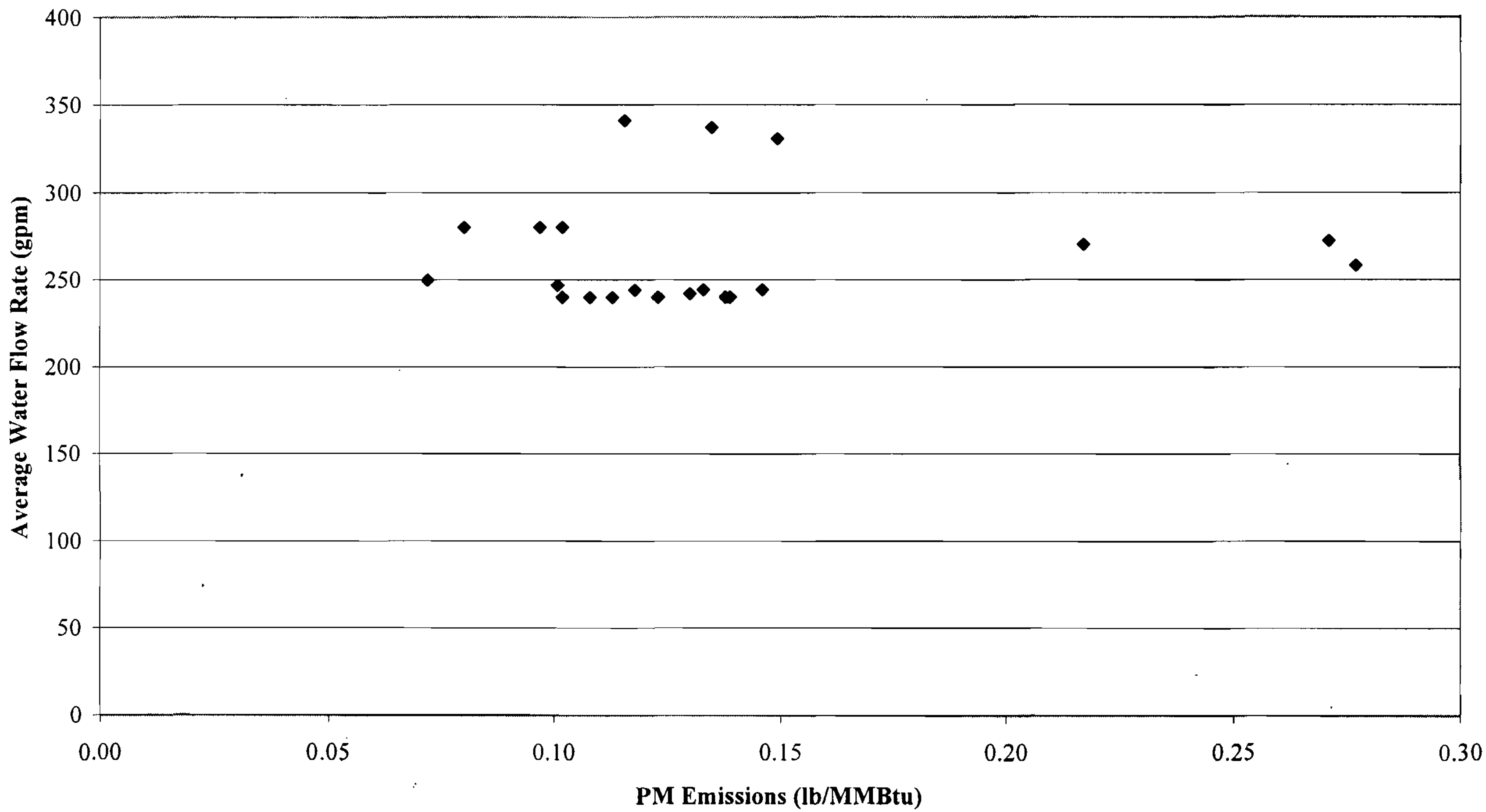
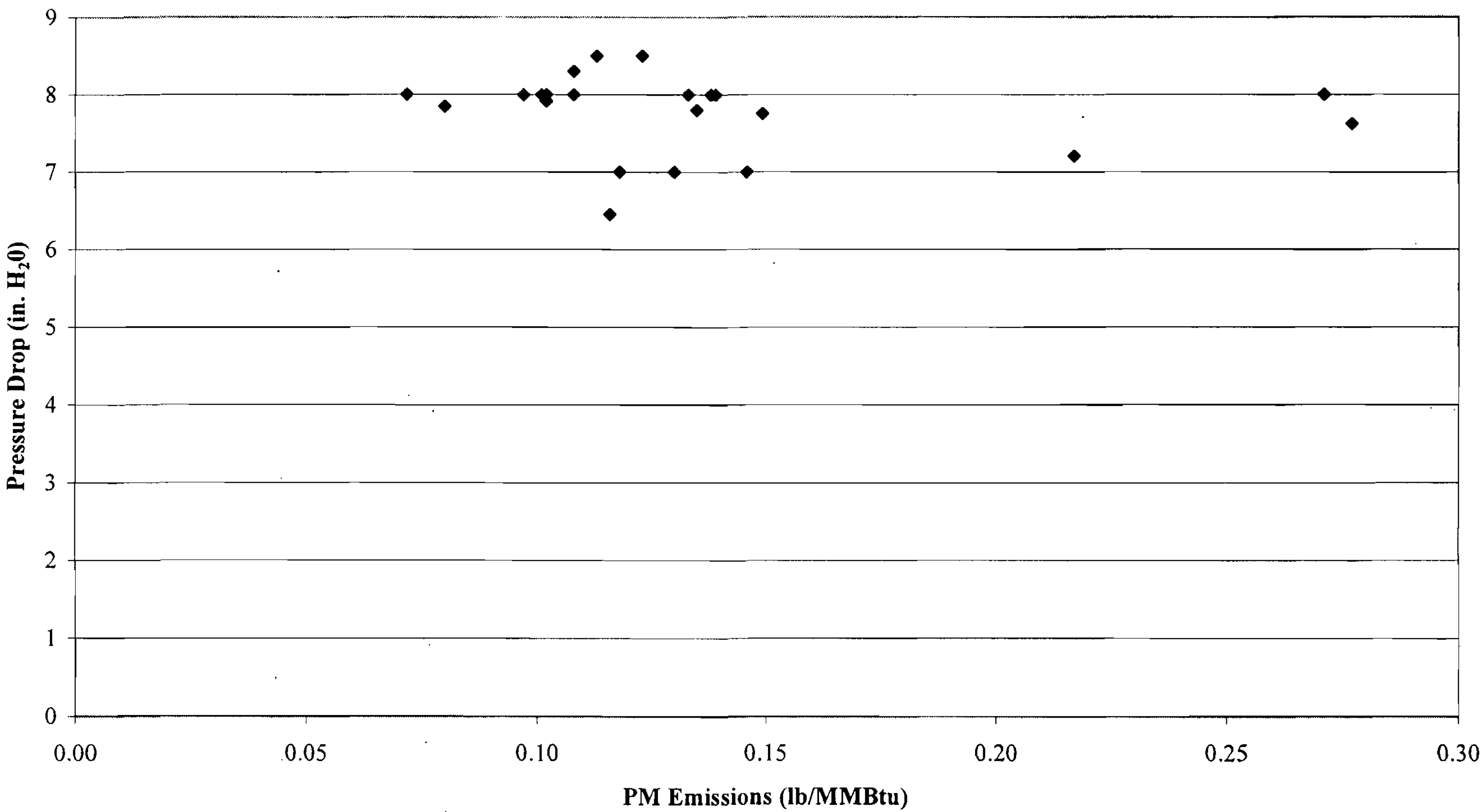


FIGURE 11-2
PM vs. Pressure Drop
Bryant Boiler No. 3



12.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 5

12.1 Emissions Unit Identification

Bryant Boiler No. 5 - EU ID 005

12.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

Boiler No. 5 has a PM emission limit of 0.15 lb/MMBtu for carbonaceous fuel plus 0.1 lb/MMBtu for No. 6 fuel oil (Permit No. 0990061-006-AV). The equivalent potential emissions are 100.7 lb/hr and 154.3 TPY for carbonaceous fuel and 21.6 lb/hr and 2.9 TPY for No. 6 fuel oil. The current VE limit is 20-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 5. In addition, the total pressure drop across the scrubber, the scrubber water inlet pressure, and the scrubber water supply flow rate must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0990061-006-AV).

12.3 Control Technology Description

PM emissions from Boiler No. 5 are controlled by two Joy Turbulaire Impingement Scrubbers, Size 100, Type D. The operating pressure drop across each scrubber is 8 to 14 inches H_2O. The operating scrubber water inlet pressure to each scrubber is 46 to 63 psig. The effectiveness of the wet scrubbers is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU10-I3).

12.4 Monitoring Approach

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 5	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across each scrubber.	Total water flow rate to the scrubbers.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 7.2 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any total water flow rate below 765 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

12.5 Justification

Both pressure drop across the scrubbers and water flow rate to the scrubbers are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubbers.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of

adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has historic test data to establish indicator values for pressure drop and total water flow rate to the Boiler No. 5 wet scrubbers. The test data correlating the parameters to the PM emission levels are presented in Figures 12-1 through 12-3. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 8 inches H_2O
	Minimum parameter value = 8 x 0.9 = 7.2 inches H_2O
Water Flow Rate:	Minimum test run value = 850 gpm
	Minimum parameter value = 850 x 0.9 = 765 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 5 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

FIGURE 12-1
PM vs. Water Flow
Bryant Boiler No. 5

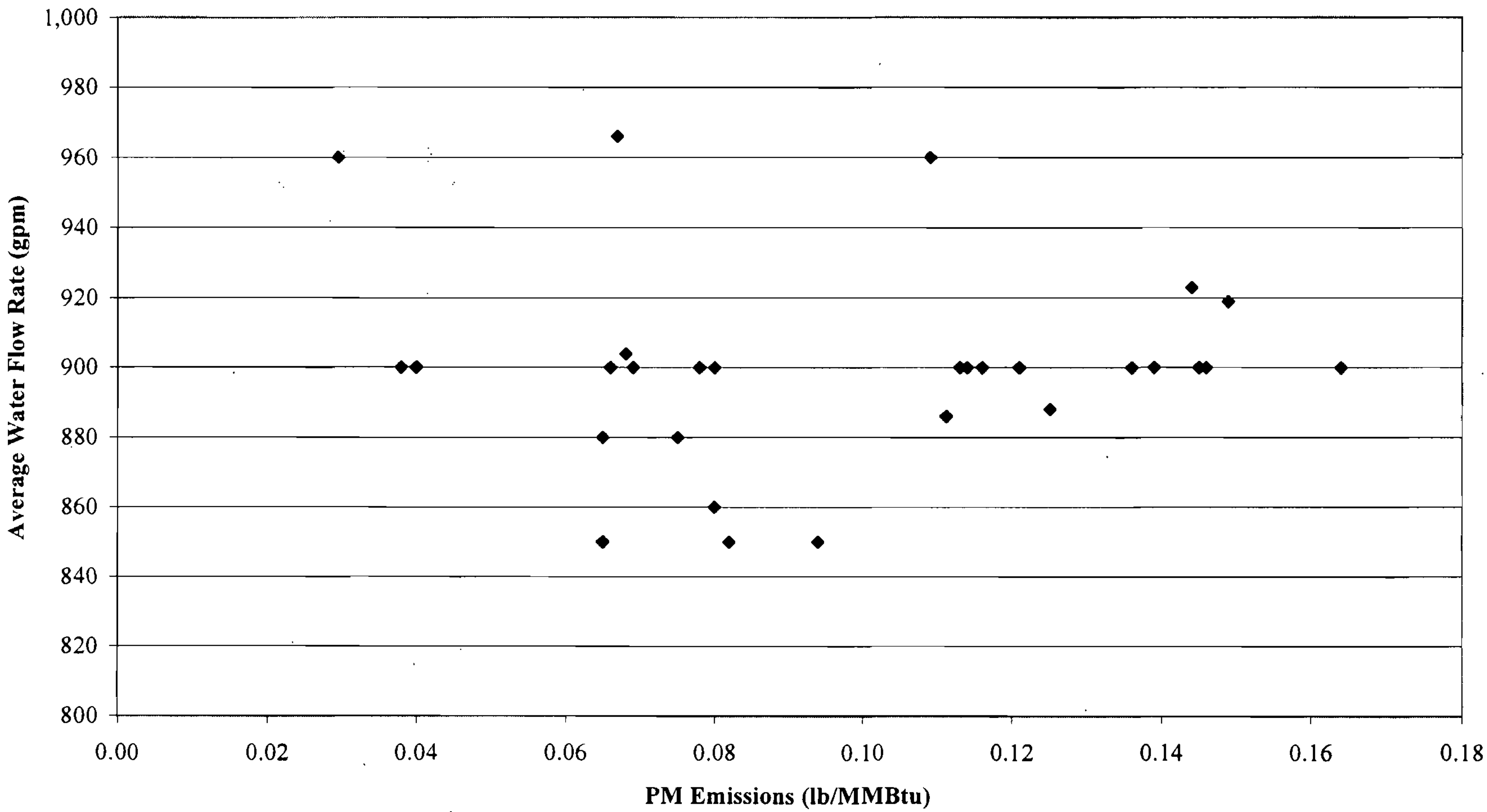


FIGURE 12-2
PM vs. Pressure Drop
Bryant Boiler No. 5 (North Scrubber)

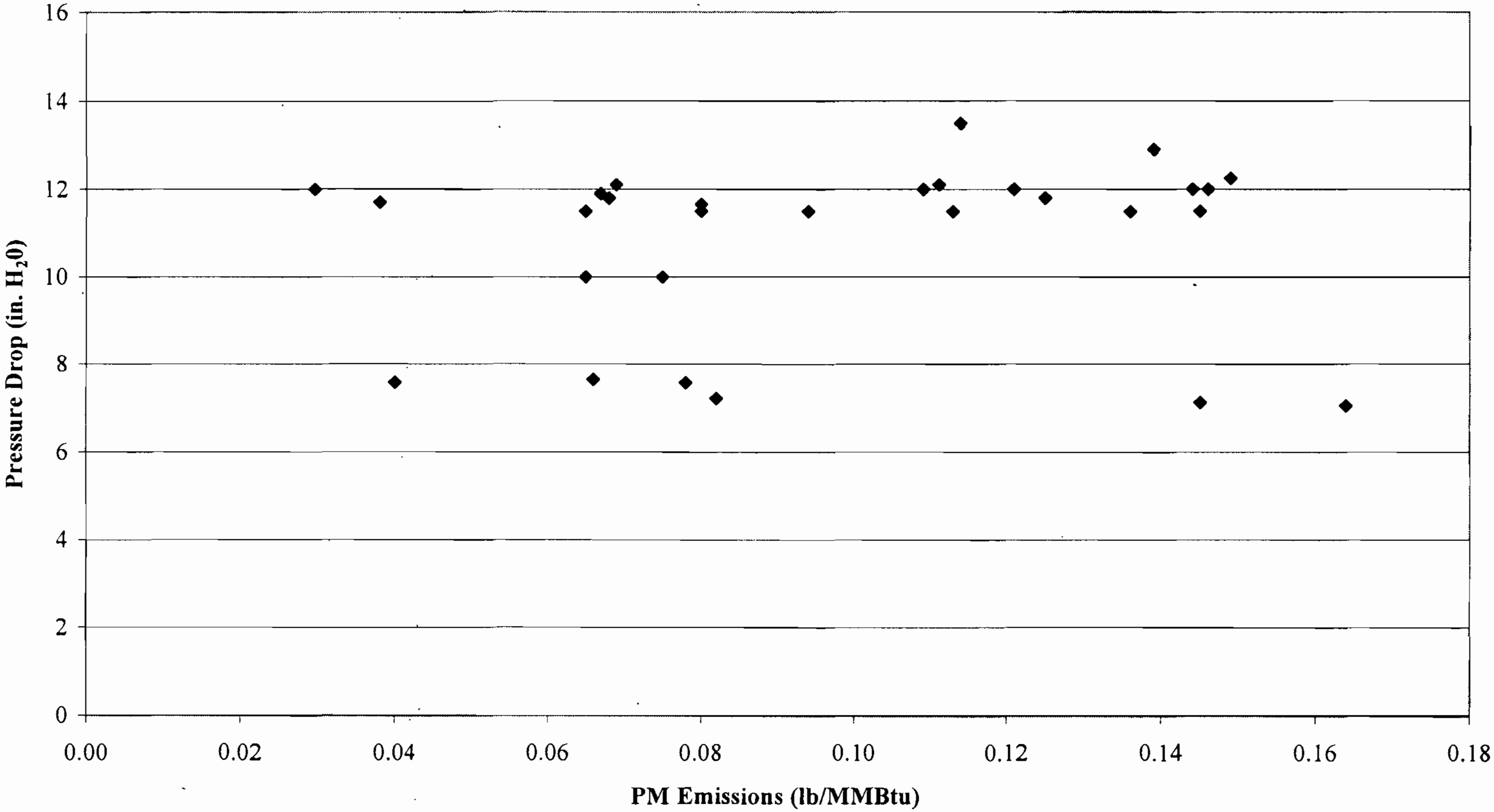
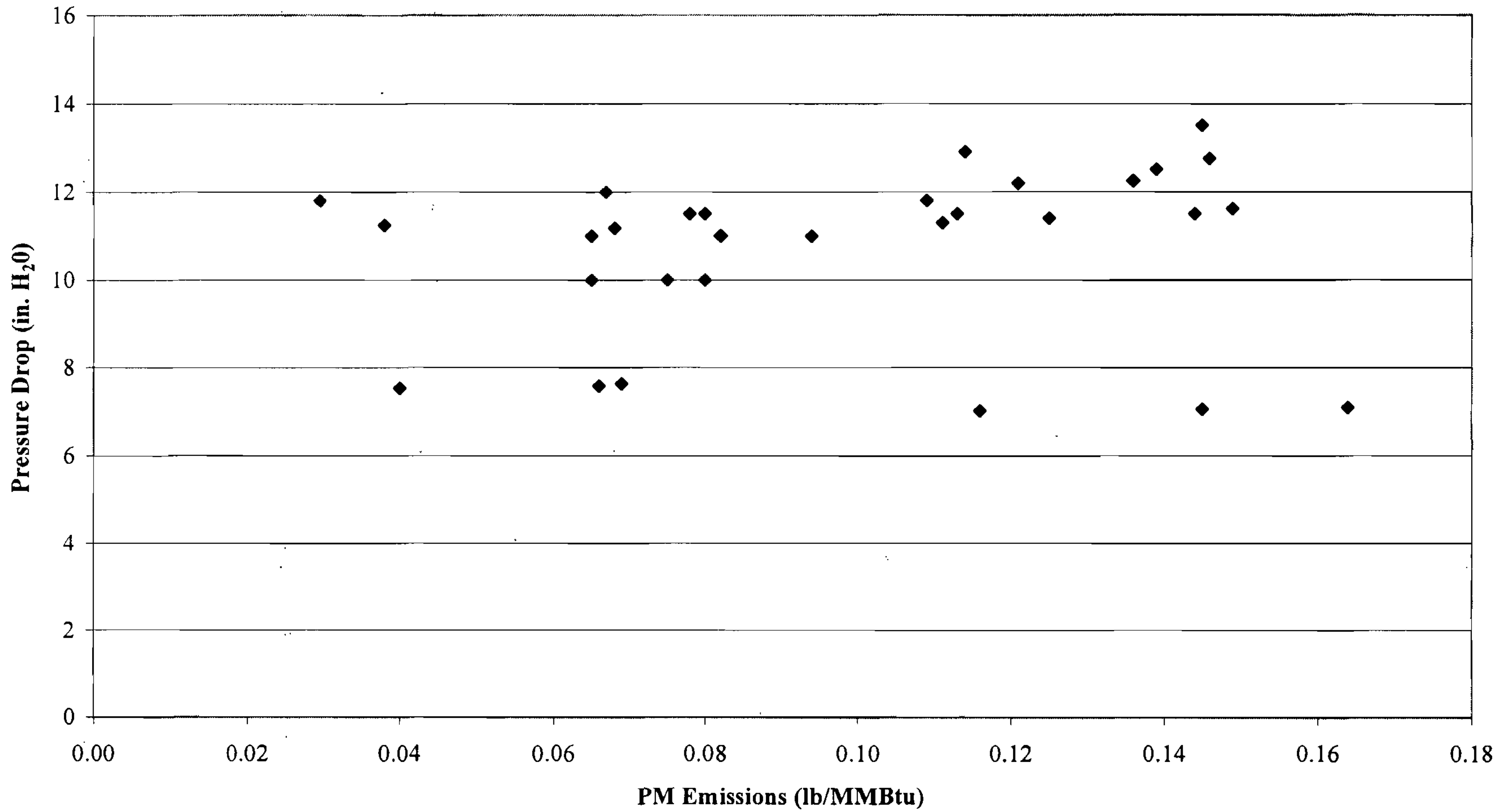


FIGURE 12-3
PM vs. Pressure Drop
Bryant Boiler No. 5 (South Scrubber)



13.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON GRANULAR CARBON REGENERATION FURNACE

13.1 Emissions Unit Identification

Clewiston Granular Carbon Regeneration Furnace – EU 017

13.2 Applicable Regulations, Emissions Limits, and Monitoring Requirements

The Granular Carbon Regeneration Furnace (GCRF) has a PM emissions limit of 0.7 lb/hr (Permit No. 0510003-017-AV) [Rule 62-212.400, F.A.C., and Permit No. 0510003-010-AC]. The equivalent potential emissions are 3.07 TPY. The current VE limit is 10 percent opacity [Permit Nos. 0510003-017-AV and 0510003-010-AC, and Rule 62-296.410(1)(b)1, F.A.C.].

VE compliance testing is required annually on the GCRF. PM tests were required upon initial startup (in 2000) and again upon Title V renewal (in 2005). In addition, the pressure drop across the venturi scrubber and the wet tray scrubber must be monitored and recorded at least once per shift during each day of operation. The afterburner temperature must also be monitored and recorded at least once per shift during each day of operation (Permit No. 0510003-017-AV).

13.3 Control Technology Description

PM emissions from the GCRF are controlled by a high-energy wet venturi scrubber, followed by a wet tray-type wet scrubber. The operating pressure drop across the venturi scrubber is 12 to 30 inches of water (H_2O). The operating pressure drop across the wet tray scrubber is 3 to 8 inches H_2O. The operating afterburner temperature is 1,200 to 1,400°F, excluding startup, shutdown, and malfunction. The effectiveness of the wet scrubbers is evaluated with a periodic stack test and annual VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU6-I3).

13.4 Monitoring Approach

The monitoring approach is based on monitoring the two scrubbers' pressure drop. The monitoring approach is summarized in the table below:

Boiler No. 1	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the venturi scrubber.	Pressure drop across the wet tray scrubber.
Measurement Approach	Pressure drop is monitored with a manometer or equivalent.	Pressure drop is monitored with a manometer or equilvalent.
Indicator Range	An excursion is defined as any pressure drop below 18 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any pressure drop below 5.6 inches H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches H_2O gauge pressure.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The nanometer is maintained in accordance with the manufacturer's recommendations.	The nanometer is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Pressure drop is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

13.5 Justification

Pressure drop across the wet scrubber is a recognized parameter for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The afterburner temperature is related to VOC destruction and not PM emissions. Therefore, this parameter is not proposed as a CAM indicator.

U.S. Sugar has historic test data to establish indicator values for pressure drop to the two wet scrubbers. The test data correlating the parameters to the PM emission levels is presented in Appendix B, Table B-3.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Venturi Scrubber Pressure Drop	Minimum test run value = 20.0 inches H_2O
	Minimum parameter value = 20 x 0.9 = 18 inches H_2O
Wet Tray Scrubber Pressure Drop	Minimum test run value = 6.2 inches H_2O
	Minimum parameter value = 6.2 x 0.9 = 5.6 inches H_2O

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDD, which are the Industrial Boiler/Process Heater MACT standards.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

APPENDIX A

SIGNATURE PAGES

APPENDIX A

SIGNATURE PAGES

APPLICATION INFORMATION

Application Responsible Official Certification

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

1.	Application Responsible Official Name: **Neil Smith, Vice President and General Manager, Sugar Processing Operations**
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☒ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3.	Application Responsible Official Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce de Leon Avenue** City: **Clewiston** State: **Florida** Zip Code: **33440**
4.	Application Responsible Official Telephone Numbers... Telephone: **(863) 902-2703** ext. Fax: **(863) 902-2729**
5.	Application Responsible Official Email Address: **nsmith@ussugar.com**
6.	Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* Signature ______ Date 8/31/06

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement: *I, the undersigned, hereby certify, except as particularly noted herein*, that:* *(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and* *(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.* *(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.* *(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.* *(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.* David A. Buff 9/1/06 Signature Date (seal)

* Attach any exception to certification statement.

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

APPENDIX B

HISTORIC PM COMPLIANCE TEST DATA

TABLE B-1

BOILER PM EMISSION TESTS, CLEWISTON

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
Boiler 1	1	Vibrating Grate	01/16/96	113,127	183,707	194,211	410.0	56.94	102.49	0.250	99.14	0.242			9.5
Boiler 1	2	Vibrating Grate	01/16/96	117,058	187,835	202,025	426.0	59.17	106.50	0.250	64.43	0.151			9.3
Boiler 1	3	Vibrating Grate	01/16/96	118,730	191,603	219,200	461.0	64.02	115.24	0.250	67.68	0.147			
Boiler 1	1	Vibrating Grate	01/07/97	125,679	200,419	203,284	426.5	59.24	106.63	0.250	57.91	0.136			9.5
Boiler 1	2	Vibrating Grate	01/07/97	123,272	198,803	210,000	440.8	61.22	110.21	0.250	62.38	0.142			9.5
Boiler 1	3	Vibrating Grate	01/07/97	122,608	200,926	211,765	443.9	61.65	110.97	0.250	56.04	0.126			9.5
Boiler 1	1	Vibrating Grate	01/08/98	148,591	223,239	193,433	404.9	56.24	101.24	0.250	39.25	0.097			9.8
Boiler 1	2	Vibrating Grate	01/08/98	139,359	211,566	209,630	440.0	61.11	103.59	0.240	42.80	0.097			10.8
Boiler 1	3	Vibrating Grate	01/08/98	141,780	215,994	204,507	430.3	59.76	103.60	0.240	54.89	0.128			10.0
Boiler 1	1	Vibrating Grate	12/08/00	116,457	185,495	193,151	406.5	56.46	99.11	0.244	78.60	0.193	67		9.0
Boiler 1	2	Vibrating Grate	12/08/00	117,435	189,657	198,261	419.3	58.23	101.82	0.243	69.20	0.165	62		7.0
Boiler 1	3	Vibrating Grate	12/08/00	114,205	187,798	195,833	414.0	57.50	100.68	0.243	80.96	0.196	65		7.0
Boiler 1	1	Vibrating Grate	12/05/01	122,015	182,934	198,000	403.3	56.01	96.73	0.240	58.44	0.145			8.8
Boiler 1	2	Vibrating Grate	12/05/01	118,508	179,141	201,127	406.5	56.46	96.79	0.238	47.69	0.117			8.0
Boiler 1	3	Vibrating Grate	12/05/01	118,063	177,096	205,588	416.0	57.78	99.18	0.238	51.10	0.123			7.5
Boiler 1	1	Vibrating Grate	11/20/02	139,322	201,193	192,329	386.2	53.64	92.96	0.241	63.82	0.165	91.6		10.5
Boiler 1	2	Vibrating Grate	11/20/02	132,473	194,240	197,391	398.7	55.37	95.88	0.240	81.67	0.205	94		10.2
Boiler 1	3	Vibrating Grate	11/20/02	139,170	200,673	193,333	412.8	57.33	98.68	0.239	70.70	0.171	94.8		10.3
Boiler 1	1	Vibrating Grate	11/14/03	147,286	202,987	196,709	409.0	56.81	102.26	0.250	49.17	0.120	75	56*	9.0
Boiler 1	2	Vibrating Grate	11/14/03	152,860	210,916	197,813	414.8	57.61	103.69	0.250	84.77	0.204	75	57*	9.0
Boiler 1	3	Vibrating Grate	11/14/03	155,202	215,710	204,000	412.2	57.24	103.04	0.250	83.72	0.203	75	56*	9.0
Boiler 1	1	Vibrating Grate	01/13/05	161,467	245,339	197,391	429.2	59.60	107.29	0.250	77.96	0.182	120	370	11.6
Boiler 1	2	Vibrating Grate	01/13/05	164,310	250,264	186,835	402.0	55.83	100.50	0.250	76.50	0.190	120	364	11.5
Boiler 1	3	Vibrating Grate	01/13/05	162,661	244,548	195,652	425.0	59.02	106.24	0.250	81.49	0.192	125	364	11.6
Boiler 1	1	Vibrating Grate	12/16/05	135,375	215,916	174,000	362.1	50.28	90.51	0.250	120.04	0.332	140	372	12.0
Boiler 1	2	Vibrating Grate	12/16/05	136,281	216,285	179,143	376.3	52.26	94.07	0.250	61.55	0.164	140	387	12.0
Boiler 1	3	Vibrating Grate	12/16/05	137,233	212,492	177,568	370.9	51.51	92.71	0.250	48.20	0.130	140	367	12.0

* Not considered to be representative of normal operation.

TABLE B-1

BOILER PM EMISSION TESTS, CLEWISTON

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
Boiler 2	1	Vibrating Grate	01/22/96	105,831	163,718	177,188	371.7	51.63	92.93	0.250	73.62	0.198			6.0
Boiler 2	2	Vibrating Grate	01/22/96	94,417	150,521	177,188	371.7	51.63	92.93	0.250	66.10	0.178			6.0
Boiler 2	3	Vibrating Grate	01/22/96	93,727	154,170	181,184	379.7	52.74	94.93	0.250	52.37	0.138			6.0
Boiler 2	1	Vibrating Grate	01/12/98	107,485	165,905	172,286	363.3	50.45	90.82	0.250	45.54	0.125			3.0
Boiler 2	2	Vibrating Grate	01/12/98	106,311	165,445	173,824	366.9	50.96	91.72	0.250	48.70	0.133			3.0
Boiler 2	3	Vibrating Grate	01/12/98	104,790	166,166	175,522	370.3	51.43	92.57	0.250	69.51	0.188			
Boiler 2	1	Vibrating Grate	01/13/98	126,475	198,634	201,739	425.1	59.03	101.08	0.240	71.72	0.169			8.5
Boiler 2	2	Vibrating Grate	01/13/98	122,422	195,643	202,059	426.2	59.19	106.55	0.250	71.59	0.168			8.5
Boiler 2	3	Vibrating Grate	01/13/98	125,162	197,964	202,388	427.0	59.31	101.42	0.240	98.31	0.230			8.5
Boiler 2	1	Vibrating Grate	12/12/00	113,638	186,994	169,459	364 4	50.61	87.57	0.240	47.53	0.130	67		8.5
Boiler 2	2	Vibrating Grate	12/12/00	108,878	181,681	174,167	373.3	51.84	88.14	0.236	60.87	0.163	61		8.2
Boiler 2	3	Vibrating Grate	12/12/00	107,998	181,348	163,714	350 3	48.65	81.96	0.234	77.50	0.221	68		8.7
Boiler 2	1	Vibrating Grate	12/12/01	141,555	214,981	212,055	435.1	60.43	103.50	0.238	112.59	0.259			9.3
Boiler 2	2	Vibrating Grate	12/12/01	125,108	187,343	182,535	374.2	51.97	93.55	0.250	73.38	0.196			
Boiler 2	3	Vibrating Grate	12/12/01	127,585	200,931	195,211	403.0	55 97	100.75	0.250	108.53	0.269			
Boiler 2	1	Vibrating Grate	12/17/02	135,626	203,449	173,239	354.6	49.25	88.64	0.250	64.49	0.182	91.8		7.1
Boiler 2	2	Vibrating Grate	12/17/02	133,618	201,955	174,167	356.6	49.53	89.16	0.250	65.36	0.183	90		7.1
Boiler 2	3	Vibrating Grate	12/17/02	134,529	201,199	189,851	389.0	54.03	97.26	0.250	67.82	0.174	80.6		6.3
Boiler 2	1	Vibrating Grate	11/18/03	125,842	196,117	183,478	387 5	53.82	96.88	0.250	88.89	0.229	51.2	75*	10.0
Boiler 2	2	Vibrating Grate	11/18/03	132,395	205,353	190,746	405.7	56.35	101.42	0.250	76.69	0.189	50.38	70*	9.0
Boiler 2	3	Vibrating Grate	11/18/03	123,840	199,614	192,537	407.4	56.58	101.84	0.250	72.78	0.179	45	65*	9.0
Boiler 2	1	Vibrating Grate	11/12/04	153,146	235,990	189,565	399.1	55.43	95.26	0.239	88.69	0.222	123.6	113*	9.5
Boiler 2	2	Vibrating Grate	11/12/04	150,689	235,118	198,000	417.9	58.05	102.27	0.245	72.18	0.173	130	123*	9.1
Boiler 2	3	Vibrating Grate	11/17/04	174,817	260,767	197,838	424.1	58.91	101.25	0.239	26.34	0.062			
Boiler 2	1	Vibrating Grate	12/14/05	116,370	174,405	183,478	383.2	53.22	85.21	0.222	77.93	0.203	115	354	12.0
Boiler 2	2	Vibrating Grate	12/14/05	140,607	219,765	170,000	354.5	49.24	88.62	0.250	63.04	0.178	115	354	12.0
Boiler 2	3	Vibrating Grate	12/14/05	137,722	214,970	177,500	371.4	51.58	92.84	0.241	64.10	0.173	115	353	12.0

* Not considered to be representative of normal operation.

TABLE B-1

BOILER PM EMISSION TESTS, CLEWISTON

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			
Boiler 4	1	Traveling Grate	02/23/94	134,590	215,068	283,043	616.9	85.68	92.54	0.150	81.72	0.132	40.5	428	
Boiler 4	2	Traveling Grate	02/23/94	136,057	218,507	290,769	633.1	87.94	94.97	0.150	73.42	0.116	40.6	430	
Boiler 4	3	Traveling Grate	02/23/94	132,839	216,547	284,308	618.0	85.83	92.70	0.150	93.94	0.152	41.2	433	
Boiler 4	1	Traveling Grate	12/30/94	152,950	222,172	288,750	626.8	87.06	94.02	0.150	88.74	0.142	50	492	10.0
Boiler 4	2	Traveling Grate	12/30/94	142,730	220,121	280,986	609.4	84.64	91.41	0.150	70.23	0.115	50	492	10.0
Boiler 4	3	Traveling Grate	12/30/94	144,948	225,530	281,918	614.3	85.32	92.15	0.150	73.08	0.119	50	492	10.0
Boiler 4	1	Traveling Grate	12/22/95	147,476	227,747	290,548	617.5	85.76	92.62	0.150	59.28	0.096	53	300	9.5
Boiler 4	2	Traveling Grate	12/22/95	143,821	222,383	280,946	597.7	83.01	89.65	0.150	63.06	0.106	54	300	9.5
Boiler 4	3	Traveling Grate	12/22/95	145,645	221,056	291,200	617.4	85.75	92.61	0.150	52.29	0.085	55	300	9.5
Boiler 4	1	Traveling Grate	12/17/96	154,554	236,304	289,909	608.8	84.56	91.32	0.150	67.58	0.111	48	245	9.5
Boiler 4	2	Traveling Grate	12/17/96	159,316	241,659	291,818	610.9	84.85	91.64	0.150	70.56	0.116	48	245	9.5
Boiler 4	3	Traveling Grate	12/17/96	156,697	239,434	286,462	601.1	83.49	90.17	0.150	61.82	0.103	48	245	9.5
Boiler 4	1	Traveling Grate	01/05/00	136,759	210,179	238,378	509.0	70.69	73.93	0.145	66.45	0.131		380	8.5
Boiler 4	2	Traveling Grate	01/05/00	136,322	209,218	241,644	514.5	71.46	75.28	0.146	64.16	0.125		390	9.0
Boiler 4	3	Traveling Grate	01/05/00	135,432	208,934	236,800	504.8	70.11	73.99	0.147	55.95	0.111		420	8.5
Boiler 4	1	Traveling Grate	11/17/00	161,372	248,028	258,400	558.2	77.53	83.72	0.150	50.40	0.090	66.4	384	10.2
Boiler 4	2	Traveling Grate	11/17/00	160,074	248,560	256,667	554.7	77.04	83.21	0.150	60.47	0.109	66.4	385	9.6
Boiler 4	3	Traveling Grate	11/17/00	161,936	249,043	262,192	566.9	78.74	85.03	0.150	51.23	0.090			9.3
Boiler 4	1	Traveling Grate	01/23/02	158,108	238,305	255,882	549.8	76.37	82.48	0.150	48.91	0.089	52	477	12.7
Boiler 4	2	Traveling Grate	01/23/02	151,705	231,241	257,647	555.6	77.17	83.34	0.150	32.17	0.058	53	482	10.7
Boiler 4	3	Traveling Grate	01/23/02	155,993	236,906	260,294	561.3	77.96	84.20	0.150	34.81	0.062	67	544	9.5
Boiler 4	1	Traveling Grate	12/18/02	167,367	250,551	272,000	600.4	83.39	90.06	0.150	66.32	0.110	64	533	15.5
Boiler 4	2	Traveling Grate	12/18/02	164,949	247,408	272,000	599.9	83.32	89.98	0.150	57.41	0.096	62.2	534	14.2
Boiler 4	3	Traveling Grate	12/18/02	161,294	241,460	274,783	601.7	83.57	90.26	0.150	54.65	0.091	62.8	537	16.5
Boiler 4	4	Traveling Grate	12/19/02	163,340	245,494	284,250	627.4	87.13					64.5	491	13.2
Boiler 4	1	Traveling Grate	11/21/03	184,631	280,071	265,479	579.9	80.54	86.98	0.150	84.74	0.146	51.02	359	22.5
Boiler 4	2	Traveling Grate	11/21/03	187,732	272,428	264,167	576.9	80.12	86.53	0.150	72.85	0.126	45.84	406	22.4
Boiler 4	3	Traveling Grate	11/21/03	179,768	261,129	260,000	567.1	78.77	85.07	0.150	61.34	0.108	55.38	409	22.4
Boiler 4	1	Traveling Grate	11/24/04	164,581	254,686	267,115	588.5	81.73	88.27	0.150	71.68	0.122	72.86	493	11.0
Boiler 4	2	Traveling Grate	11/24/04	165,619	262,011	259,737	572.2	79.47	85.83	0.150	74.10	0.130	71.67	492	11.0
Boiler 4	3	Traveling Grate	11/24/04	165,111	263,455	246,923	542.8	75.39	81.42	0.150	79.60	0.147	72.4	490	11.0
Boiler 4	4	Traveling Grate	11/24/04	166,378	265,717	254,526	558.2	77.53	83.73	0.150	74.71	0.134	70.67	419	11.0
Boiler 4	1	Traveling Grate	02/10/05	156,977	228,241	237,600	515.1	71.54	77.26	0.150	58.57	0.114	78.6	611	11.0
Boiler 4	2	Traveling Grate	02/10/05	158,258	233,152	239,178	516.5	71.73	77.47	0.150	59.15	0.115	80.2	623	10.9
Boiler 4	3	Traveling Grate	02/10/05	161,994	235,662	230,649	500.5	69.52	75.08	0.150	53.51	0.107	78.6	623	11.0
Boiler 4	1	Traveling Grate	01/13/06	127,859	203,260	229,014	478.3	66.43	71.75	0.150	53.96	0.113	50	356	9.9
Boiler 4	2	Traveling Grate	01/13/06	123,326	198,482	244,225	510.4	70.88	76.55	0.150	34.27	0.067	51	360	10.0
Boiler 4	3	Traveling Grate	01/13/06	122,129	196,063	236,522	498.0	69.16	74.70	0.150	48.24	0.097	51.4	361	10.0

TABLE B-1

BOILER PM EMISSION TESTS, CLEWISTON

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
Boiler 7	1	Spreader-Stoker Vibrating Grate	02/04/05	165,392	296,331	232,174	494.28	68.65	14.83	0.030	11.57	0.023	49.32		
Boiler 7	2	Spreader-Stoker Vibrating Grate	02/04/05	161,579	296,174	228,000	487.84	67.76	14.64	0.030	6.84	0.014	55.14		
Boiler 7	3	Spreader-Stoker Vibrating Grate	02/04/05	159,426	285,860	223,099	475.52	66.04	14.27	0.030	13.03	0.027	70.01		
Boiler 7	1	Spreader-Stoker Vibrating Grate	01/05/06	184,525	318,378	318,300	659.85	91.65	19.80	0.030	13.47	0.020	60.1		
Boiler 7	2	Spreader-Stoker Vibrating Grate	01/05/06	178,105	315,125	348,674	721.46	100.20	21.64	0.030	9.96	0.014	63.9		
Boiler 7	3	Spreader-Stoker Vibrating Grate	01/05/06	173,265	306,013	349,209	720.61	100.08	21.62	0.030	8.77	0.012	67.9		

Notes:

lb/hr = pounds per hour.

lb/MMBtu = pounds per million British thermal units.

lb/ton = pounds per ton.

MMBtu/hr = million British thermal units per hour.

TPH = tons per hour.

Footnotes:

[1] Assumed 3,600 Btu/lb average heat content for wet bagasse, except where noted.

TABLE B-2
BOILER PM EMISSION TESTS, BRYANT

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate	Stack Gas Flow Rate	Steam Rate	Heat Input Rate	Bagasse Burning Rate [1]	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure	Avg. Water Flow	Avg. Pressure Drop
				(dscfm)	(acfm)	(lb/hr)	(MMBtu/hr)	(TPH)	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	(psig)	(gpm)	(in. H_2O)
Boiler 1	1	Vibrating Grate	12/06/95	86,294	139,819	181,500	343.1	47.65	102.92	0.300	29.39	0.086	37	246	6.4
Boiler 1	2	Vibrating Grate	12/06/95	79,708	116,374	176,962	333.9	46.38	100.18	0.300	30.48	0.091	44.0	220	6.0
Boiler 1	3	Vibrating Grate	12/06/95	92,589	137,658	178,421	335.8	46.64	100.75	0.300	39.05	0.116	45	225	6.2
Boiler 1	1	Vibrating Grate	11/20/00	88,333	139,209	151,965	293.3	40.74	87.99	0.300	38.85	0.132		299	9.0
Boiler 1	2	Vibrating Grate	11/20/00	88,077	136,966	148,445	287.7	39.95	86.29	0.300	40.40	0.140		300	9.0
Boiler 1	3	Vibrating Grate	11/20/00	89,206	139,900	144,789	280.2	38.92	84.07	0.300	38.43	0.137		303	9.0
Boiler 1	1	Vibrating Grate	11/27/01	90,185	146,160	156,675	304.4	42.28	91.31	0.300	69.98	0.230	57	277	9.5
Boiler 1	2	Vibrating Grate	11/27/01	92,735	159,796	155,634	304.0	42.23	91.21	0.300	16.46	0.054	57	275	9.3
Boiler 1	3	Vibrating Grate	11/27/01	90,224	152,446	162,750	319.1	44.32	95.73	0.300	23.11	0.072	57	275	9.3
Boiler 1	1	Vibrating Grate	11/27/02	88,588	142,319	155,926	299.0	41.52	89.69	0.300	38.78	0.130	55.3	240	9.0
Boiler 1	2	Vibrating Grate	11/27/02	85,497	143,200	163,425	314.1	43.63	94.23	0.300	16.38	0.052	55.5	240	9.0
Boiler 1	3	Vibrating Grate	11/27/02	87,341	141,308	158,308	304.5	42.30	91.36	0.300	23.38	0.077	55	240	9.0
Boiler 1	1	Vibrating Grate	12/05/03	68,695	114,572	158,518	303.0	42.09	90.91	0.300	35.15	0.116	60	240	9
Boiler 1	2	Vibrating Grate	12/05/03	83,983	127,692	160,887	303.9	42.20	91.16	0.300	29.90	0.098	60	240	9
Boiler 1	3	Vibrating Grate	12/05/03	95,884	149,510	162,301	309.0	42.92	92.71	0.300	43.62	0.141	59.7	240	9
Boiler 1	1	Vibrating Grate	12/03/04	77,079	123,377	159,730	303.2	42.11	90.96	0.300	32.84	0.108		240	8.0
Boiler 1	2	Vibrating Grate	12/03/04	77,794	127,123	162,969	310.2	43.08	93.05	0.300	27.97	0.090		240	8.0
Boiler 1	3	Vibrating Grate	12/03/04	82,959	131,088	162,433	307.6	42.73	92.29	0.300	37.32	0.121		240	8.0
Boiler 1	1	Vibrating Grate	11/18/05	90,275	156,359	157,785	302.5	42.01	90.74	0.300	39.36	0.130	61.8	240	9.5
Boiler 1	2	Vibrating Grate	11/18/05	92,983	152,116	152,353	290.9	40.40	87.26	0.300	38.93	0.134	61.8	240	9.5
Boiler 1	3	Vibrating Grate	11/18/05	95,704	158,532	152,368	287.3	39.91	86.20	0.300	42.33	0.147	60.7	240	9.0

TABLE B-2

BOILER PM EMISSION TESTS, BRYANT

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate	Stack Gas Flow Rate	Steam Rate	Heat Input Rate	Bagasse Burning Rate [1]	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure	Avg. Water Flow	Avg. Pressure Drop (in. H_2O)	
				(dscfm)	(acfm)	(lb/hr)	(MMBtu/hr)	(TPH)	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	(psig)	(gpm)	North	South
Boiler 2	1	Vibrating Grate	12/07/95	82,812	123,640	160,741	301.0	41.80	90.29	0.300	68.31	0.227	50	225	7.0	6.0
Boiler 2	2	Vibrating Grate	12/07/95	78,950	116,459	165,385	310.0	43.05	92.99	0.300	52.70	0.170	51.7	229	7.0	6.0
Boiler 2	3	Vibrating Grate	12/07/95	69,899	103,638	167,368	314.0	43.61	94.20	0.300	45.61	0.145	49	233	7.0	7.0
Boiler 2	1	Vibrating Grate	11/29/00	90,012	135,845	161,786	310.8	43.17	93.25	0.300	35.78	0.118	60	359	3.9	4.7
Boiler 2	2	Vibrating Grate	11/29/00	86,272	134,092	152,734	297.8	41.36	89.34	0.300	40.93	0.137	60	358	4.1	5.0
Boiler 2	3	Vibrating Grate	11/29/00	90,062	135,845	153,740	302.0	41.94	90.60	0.300	35.78	0.118	60.7	360	4.5	5.1
Boiler 2	1	Vibrating Grate	11/26/01	85,353	134,931	158,835	307.3	42.68	92.20	0.300	32.68	0.106	62	355	4.5	
Boiler 2	2	Vibrating Grate	11/26/01	79,486	128,541	158,096	308.1	42.79	92.43	0.300	31.37	0.102	62	355	5.0	
Boiler 2	3	Vibrating Grate	11/26/01	84,295	129,729	161,926	313.5	43.54	94.04	0.300	21.38	0.068	62	355	5.0	
Boiler 2	1	Vibrating Grate	11/26/02	98,154	149,921	158,864	307.7	42.74	92.31	0.300	40.06	0.130	59.3	352	4.5	4.3
Boiler 2	2	Vibrating Grate	11/26/02	91,488	147,528	161,561	311.8	43.31	93.54	0.300	31.74	0.102	59.2	353	4.3	4.3
Boiler 2	3	Vibrating Grate	11/26/02	92,399	147,765	172,208	333.2	46.28	99.96	0.300	48.13	0.144	58	360	4.3	4.3
Boiler 2	1	Vibrating Grate	12/04/03	84,651	127,322	145,626	286.6	39.80	85.97	0.300	22.35	0.078	60	360	4.2	4.0
Boiler 2	2	Vibrating Grate	12/04/03	86,574	133,711	146,100	287.4	39.92	86.22	0.300	36.53	0.127	60	360	4.0	4.0
Boiler 2	3	Vibrating Grate	12/04/03	96,457	143,427	148,679	291.4	40.48	87.43	0.300	21.97	0.075	60	360	4.2	4.0
Boiler 2	4	Vibrating Grate	12/04/03	83,436	129,793	146,542	287.6	39.95	86.29	0.300	35.79	0.124	60	360	4.3	4.1
Boiler 2	1	Vibrating Grate	12/02/04	84,055	137,921	159,488	307.1	42.65	92.12	0.300	37.17	0.121		350	4.0	4.0
Boiler 2	2	Vibrating Grate	12/02/04	79,419	131,984	157,147	302.6	42.03	90.79	0.300	38.65	0.128		360	4.0	4.0
Boiler 2	3	Vibrating Grate	12/02/04	87,454	143,563	160,603	308.9	42.90	92.66	0.300	33.07	0.107		360	4.0	4.0
Boiler 2	1	Vibrating Grate	11/17/05	108,816	170,447	148,646	286.9	39.85	86.07	0.300	64.19	0.224	61.6	360	4.5	4.0
Boiler 2	2	Vibrating Grate	11/17/05	103,144	161,449	154,290	296.2	41.13	88.85	0.300	38.86	0.131	60	360	4.8	4.0
Boiler 2	3	Vibrating Grate	11/18/05	92,702	144,726	146,996	281.6	39.11	84.48	0.300	44.12	0.157	61.8	360	4.7	4.5

TABLE B-2

BOILER PM EMISSION TESTS, BRYANT

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate	Stack Gas Flow Rate	Steam Rate	Heat Input Rate	Bagasse Burning Rate [1]	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure	Avg. Water Flow	Avg. Pressure Drop
				(dscfm)	(acfm)	(lb/hr)	(MMBtu/hr)	(TPH)	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	(psig)	(gpm)	(in. H_2O)
Boiler 3	1	Vibrating Grate	12/08/95	77,426	118,767	153,253	288.2	40.03	86.46	0.300	78.07	0.271	50	272	8.0
Boiler 3	2	Vibrating Grate	12/08/95	84,155	131,470	146,250	275.5	38.27	82.66	0.300	76.20	0.277	50	258	7.6
Boiler 3	3	Vibrating Grate	12/08/95	69,082	108,458	144,935	285.2	39.61	85.65	0.300	61.93	0.217	50	270	7.2
Boiler 3	1	Vibrating Grate	12/18/96	89,926	145,809	166,216	324.5	45.07	97.35	0.300	43.78	0.135	51	337	7.8
Boiler 3	2	Vibrating Grate	12/18/96	85,316	140,249	162,532	317.2	44.06	95.15	0.300	49.38	0.116	50.4	341	6.5
Boiler 3	3	Vibrating Grate	12/18/96	85,345	138,525	162,857	320.6	44.53	96.17	0.300	47.89	0.149	57	331	7.8
Boiler 3	1	Vibrating Grate	11/30/00	86,941		160,554	312.8	43.45	93.85	0.300	25.02	0.080	61	280	7.9
Boiler 3	2	Vibrating Grate	11/30/00	90,342		163,737	318.9	44.30	95.68	0.300	31.05	0.097	61	280	8.0
Boiler 3	3	Vibrating Grate	11/30/00	84,253		163,063	317.4	44.08	95.21	0.300	32.37	0.102	61	280	7.9
Boiler 3	1	Vibrating Grate	11/25/02	90,213		159,063	304.7	42.32	91.40	0.300	30.69	0.101	62	247	8.0
Boiler 3	2	Vibrating Grate	11/25/02	88,750		156,141	303.7	42.19	91.12	0.300	21.90	0.072	62	250	8.0
Boiler 3	3	Vibrating Grate	11/25/02	89,057		160,265	310.9	43.18	93.26	0.300	41.47	0.133	62	244	8.0
Boiler 3	1	Vibrating Grate	12/03/03	81,606		155,236	305.1	42.37	91.52	0.300	39.59	0.130	48.2	242	7.0
Boiler 3	2	Vibrating Grate	12/03/03	88,011		159,924	313.2	43.50	93.96	0.300	36.84	0.118	58	244	7.0
Boiler 3	3	Vibrating Grate	12/03/03	90,473		162,898	318.5	44.24	95.56	0.300	46.50	0.146	60	244	7.0
Boiler 3	1	Vibrating Grate	12/01/04	69,859	117,289	160,926	310.1	43.07	93.03	0.300	42.91	0.138		240	8.0
Boiler 3	2	Vibrating Grate	12/01/04	69,489	118,247	165,646	318.4	44.22	95.52	0.300	32.60	0.102		240	8.0
Boiler 3	3	Vibrating Grate	12/01/04	76,903	130,031	161,835	311.4	43.25	93.42	0.300	43.43	0.139		240	8.0
Boiler 3	1	Vibrating Grate	11/16/05	77,618	124,872	151,205	289.8	40.25	86.95	0.300	30.99	0.108	62	240	8.0
Boiler 3	2	Vibrating Grate	11/16/05	69,137	110,850	148,974	287.6	39.94	86.27	0.300	30.95	0.108	61.4	240	8.3
Boiler 3	3	Vibrating Grate	11/16/05	73,390	117,250	147,528	285.8	39.69	85.73	0.300	36.09	0.123	61.6	240	8.5
Boiler 3	4	Vibrating Grate	11/16/05	76,995	121,518	151,915	293.7	40.79	88.11	0.300	32.68	0.113	61.8	240	8.5

TABLE B-2

BOILER PM EMISSION TESTS, BRYANT

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)	
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			North	South
Boiler 5	1	Vibrating Grate	02/11/94	139,793	194,449	230,704	508.8	70.67	152.65	0.300	38.27	0.075	46	880	10.0	10.0
Boiler 5	2	Vibrating Grate	02/11/94	136,855	194,010	233,333	516.1	71.68	154.84	0.300	33.37	0.065	48	880	10.0	10.0
Boiler 5	3	Vibrating Grate	02/11/94	136,741	193,190	243,000	535.9	74.43	160.78	0.300	42.88	0.080	47	860	10.0	10.0
Boiler 5	1	Vibrating Grate	12/12/94	145,611	205,105	234,348	522.2	72.52	156.65	0.300	35.35	0.068	54.4	904	11.7	11.2
Boiler 5	2	Vibrating Grate	12/12/94	143,214	202,908	233,333	519.5	72.15	155.84	0.300	43.35	0.038	50	900	11.8	11.2
Boiler 5	3	Vibrating Grate	12/12/94	141,383	200,224	243,600	544.3	75.59	163.28	0.300	68.10	0.125	50.2	888	11.7	11.4
Boiler 5	1	Vibrating Grate	01/12/96	143,543	194,905	243,529	547.4	76.03	164.23	0.300	36.65	0.067	53.2	966	11.8	12.0
Boiler 5	2	Vibrating Grate	01/12/96	144,597	199,699	245,294	552.1	76.67	165.62	0.300	16.32	0.030	53.6	960	11.9	11.8
Boiler 5	3	Vibrating Grate	01/12/96	142,265	197,455	240,000	540.6	75.08	162.17	0.300	58.98	0.109	54	960	12.0	11.8
Boiler 5	1	Vibrating Grate	12/23/97	144,605	196,594	250,154	558.1	77.51	167.42	0.300	62.03	0.111	55	886	12.0	11.3
Boiler 5	2	Vibrating Grate	12/23/97	139,553	195,575	247,500	552.5	76.73	165.74	0.300	79.56	0.144	59.6	923	12.1	11.5
Boiler 5	3	Vibrating Grate	12/23/97	142,170	197,815	248,060	554.5	77.01	166.34	0.300	82.58	0.149	56.3	919	12.0	11.6
Boiler 5	1	Vibrating Grate	11/28/00	146,321		221,486	491.7	68.29	147.52	0.300	68.54	0.139	63	900	12.3	12.5
Boiler 5	2	Vibrating Grate	11/28/00	143,043		218,912	486.3	67.55	145.90	0.300	55.67	0.114	62	900	12.9	12.9
Boiler 5	3	Vibrating Grate	11/28/00	149,281		220,225	491.3	68.23	147.38	0.300	71.35	0.145	61.8	900	13.5	13.5
Boiler 5	1	Vibrating Grate	11/30/01	138,158		228,882	489.0	67.92	146.70	0.300	39.67	0.080	56	900	11.5	11.5
Boiler 5	2	Vibrating Grate	11/30/01	139,931		221,206	486.5	67.57	145.96	0.300	55.05	0.113	56	900	11.5	11.5
Boiler 5	3	Vibrating Grate	11/30/01	144,314		230,833	502.6	69.80	150.78	0.300	39.25	0.078	56	900	11.5	11.5
Boiler 5	1	Vibrating Grate	12/04/02	157,781		230,783	497.6	69.12	149.29	0.300	19.67	0.040	52	900	7.6	7.5
Boiler 5	2	Vibrating Grate	12/04/02	157,883		225,042	493.0	68.48	147.91	0.300	32.65	0.066	52	900	7.6	7.6
Boiler 5	3	Vibrating Grate	12/04/02	163,176		219,583	481.9	66.93	144.57	0.300	33.32	0.069	53.2	900	7.6	7.6
Boiler 5	1	Vibrating Grate	12/10/03	172,017		202,342	444.3	61.71	133.30	0.300	65.06	0.146	60	900	12.1	12.8
Boiler 5	2	Vibrating Grate	12/10/03	184,291		205,117	451.5	62.70	135.44	0.300	54.68	0.121	59.8	900	12.0	12.2
Boiler 5	3	Vibrating Grate	12/10/03	187,191		203,827	447.1	62.10	134.13	0.300	61.03	0.136	60	900	12.0	12.3
Boiler 5	1	Vibrating Grate	12/08/04	154,671	217,383	240,806	519.7	72.18	155.91	0.300	33.80	0.065		850	11.5	11.0

TABLE B-2
BOILER PM EMISSION TESTS, BRYANT

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)	
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			North	South
Boiler 5	2	Vibrating Grate	12/08/04	145,488	208,437	229,127	494.5	68.69	148.36	0.300	46.35	0.094		850	11.5	11.0
Boiler 5	3	Vibrating Grate	12/08/04	152,109	212,927	236,835	513.0	71.26	153.91	0.300	42.14	0.082		850	11.5	11.0
Boiler 5	1	Vibrating Grate	11/23/05	143,258	194,020	207,962	463.2	64.33	69.47	0.150	76.13	0.164	59.8	900	7.2	7.1
Boiler 5	2	Vibrating Grate	11/23/05	158,046	206,942	188,917	419.7	58.29	62.95	0.150	60.75	0.145	60	900	7.1	7.1
Boiler 5	3	Vibrating Grate	11/23/05	152,703	205,628	209,254	464.0	64.44	69.60	0.150	54.02	0.116	60	900	7.1	7.0

lb/MMBtu = pounds per million British thermal units.

lb/ton = pounds per ton.

MMBtu/hr = million British thermal units per hour.

TPH = tons per hour.

Footnote:

[1] Assumed 3,600 Btu/lb average heat content for wet bagasse, except where noted.

TABLE B-3

GRANULAR CARBON REGENERATION FURNACE PM EMISSION TESTS, CLEWISTON

Unit	Run Number	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Allowable PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/hr	Venturi Scrubber Avg. Pressure Drop (in. H_2O)	Wet Tray Scrubber Avg. Pressure Drop (in. H_2O)	Afterburner Avg. Temperature (deg. F)
GCRF	1	01/20/00	5,526	8,043	0.7	0.514	20.4	6.8	1,296
GCRF	2	01/20/00	5,561	8,150	0.7	0.464	20.2	6.8	1,303
GCRF	3	01/20/00	4,967	7,393	0.7	0.635	20.0	6.2	1,272
GCRF	1	09/28/05	4,844	6,420	0.7	0.288	20.0	9.0	1,300
GCRF	2	09/29/05	4,768	6,865	0.7	0.321	20.0	9.0	1,291
GCRF	3	09/29/05	4,934	7,117	0.7	0.550	20.0	9.0	1,290

Notes:

lb/hr = pounds per hour.

ATTACHMENT B

GRANULAR CARBON REGENERATIVE FURNACE DESIGN INFORMATION

BSP THERMAL SYSTEMS, INC.
1121 INDUSTRIAL ROAD, SUITE "D"
SAN CARLOS, CA 94070
(415) 591-6762/800-222-5575
FAX (415) 591-1383

Transmitted 3/11/96

FAX MESSAGE

DATE: 3/6/97

TIME: ~~8:25 A.M.~~

TO: STONE & WEBSTER ENGINEEERS

FROM: R.H. KEELER

CC: M. ISHEIM

ATTN: [redacted]

FAX #: 1-770-481-4110

NO. OF PAGES (Including this page): 2

SUBJECT: CARBON REGEN SYSTEM
10'-9" OD X 8 + 0 HTH UNIT
40,000#/DAY PRODUCT DESIGN RATE (CANE SUGAR)

MESSAGE:

PER YOUR REQUEST AND TO SATISFY THE 40,000#/DAY PRODUCTION REQUIREMENTS FOR CANE SUGAR, WE REVISE OUR ORIGINAL SCOPE AND PRICING TO REFLECT THE NEW PARAMETERS.

OUR PREVIOUS BUDGET PRICING AND PRELIMINARY SCOPE OF WORK AS OUTLINED IN OUR LETTER OF 15 JULY '93 IS REVISED AS FOLLOWS:

A. FURNACE SIZE IS NOW 10'-9" O.D. X 8+0 HEARTH AFTERBURNER.
B. EQUIPMENT SUPPLIED SAME AS BUDGET PROPOSAL ITEM I, EXCEPT ITEM J - OFF-GAS SYSTEM IS REMOVED UNTIL CLARIFICATION OF OFF GAS SYSTEM PARAMETERS IS DEFINED.
C. ITEM V - PRICE AND DELIVERY. BASED ON INCREASE ON STAINLESS STEEL, LABOR, AND EQUIPMENT ESCALATION, OUR BUDGET PRICE FOR ONE (1) 10'-9" O.D. X 8+0 HTH UNIT IS $926,000 PLUS OR MINUS 10%.

PROCESS DATA REQUESTED:

1. ANTICIPATED OFF-GAS TO STEAM BOILER
   11,000#/HR DRY GAS
   5,000#/HR H2O
   16,000#/HR TOTAL @ 1300-1400 DEG. F
2. PARTICULATES - 26#/HR
3. DRY GAS ANALYSIS:
   CO2 12.366% = 1360#/HR
   O2 6.941% = 764#/HR
   N2 80.693# = 8876#/HR
   TOTAL - - - - 11,000#/HR

4. ANTICIPATED EMISSIONS WITH AFTERBURNER

NOX	1.84 #/HR
SO2	7.04 #/HR — made a best estimate used in corn sugar plants
CO	1.76 #/HR
VOC	0.68#/HR

WHEN THIS INQUIRY BECOMES A FIRM BID PROPOSAL, WE WOULD APPRECIATE S&W FILLING OUT OUR PROCESS QUESTIONAIRE SO FIRM PROCESS PARAMETERS CAN BE USED FOR PRICING EQUIPMENT. IN ADDITION, WE WILL BE ISSUING A NEW PROPOSED PLANT ARRANGEMENT FOR YOUR USE IN DESIGNING THE BUILDING STRUCTURE WHEN A FIRM PRICE BID REQUEST IS RECEIVED.

WE TRUST THE ABOVE SATISFIES YOUR REQUIREMENTS AT THIS TIME.

BSP THERMAL SYSTEMS, INC.
1121 INDUSTRIAL ROAD, SUITE "D"
SAN CARLOS, CA 94070
(415) 591-6762/800-222-5575
FAX (415) 591-1383

FAX MESSAGE

DATE: 7/22/96 TIME: 9:00 A.M.

TO: STONE & WEBSTER ENGINEEERS FROM: R.H. KEELER

CC: A. FOMIN
M. ISHEIM

ATTN: [redacted]

FAX #: 1-770-481-4110

NO. OF PAGES (including this page): 2

SUBJECT: CARBON REGEN SYSTEM (S&W 7/15/96)
10'-9" OD X 8 + 0 HTH UNIT
EMISSIONS DATA
BSP PROPOSAL #E-1056

MESSAGE:
ED:
PER YOUR REQUEST, WE OUTLINE BELOW EMISSIONS DATA RELATED TO FURNACE OFF-GAS SYSTEM AND OUR ESTIMATE OF ITS EFFICIENCY. PLEASE UNDERSTAND THAT THIS DATA IS ESTIMATED AT THIS TIME AS WE HAVE NO ADSORBATE OR PROXIMATE ANALYSIS DATA FROM WHICH TO BASE FIRM FIGURES. OUR DATA IS BASED ON OUR RECENT EXPERIENCE ON THE MANY REGENERATION UNITS INSTALLED BY BSP FOR THE CORN MILLING, CANE SUGAR, AND WASTEWATER TREATMENT PLANTS.

AFTERBURNER - MODEL BSP ZERO HEARTH TYPE FOR 10'-9" OD X 8 HTH FURNACE.

OUTLET GAS TEMP.	1200 DEG. F - 1400 DEG. F	
OUTLET GAS FLOW RATE	10.600 MIN. 16,300 MAX. ACFM AT 1400 DEG. F.	
GAS RESIDENCE TIME	0.5 SEC. MIN., 0.75 SEC. MAX.	
MHF TEMPERATURE	HTH 1	800 DEG. F.
	HTH 8	1600 DEG. F.
EST. VOC EFF.	ESTIMATE = 92%	

SCRUBBER SYSTEM - SLY MFG CO. HIGH ENERGY VENTURI WITH TRAY TYPE SCRUBBER

INLET GAS VOLUME	14,900 ACFM AT 1400 DEG. F.
OUTLET GAS VOLUME	4,300 ACFM AT 160 DEG. F.
PRESSURE DROP ACROSS VENTURI	20 - 30" WC
PRESSURE DROP ACROSS SCRUBBER	3 - 5" WC

FAXMSG TO ED LAVERGNE
PAGE 2 OF 2
7/22/96

WATER FLOW RATES

VENTURI INLET	10 GPM	FREE FLOW
PRECOOLER WATER SPRAY	16 GPM	20 PSIG
VENTURI H20	36 GPM	3 PSIG
SCRUBBER OKATE H20	230 GPM	FREE FLOW
TOTAL - - -	292 GPM	
SCRUBBER MAKE UP WATER	4.5 GPM	CONTINUOUS BLOW DOWN
PARTICULATE IN	23 - 26 LBS/HR - ALL PM-10	
PARTICULATE OUT	0.65 - 0.70 LBS/HR.	
EFFICIENCY	97 - 98%	

OTHER POLLUTANTS GIVEN IN PREVIOUS CORRESPONDENCE.

AS ALWAYS PLEASE TREAT THIS INFORMATION AS CONFIDENTIAL.

REGARDS,

ROB KEELER

ATTACHMENT C

REVISED TITLE V APPLICATION PAGES

ATTACHMENT USS-FI-CV3a

COMPLIANCE REPORT AND PLAN

ATTACHMENT USS-FI-CV3a

COMPLIANCE REPORT AND PLAN

United States Sugar Corporation
Clewiston Mill

This Compliance Report and Plan for United States Sugar Corporation (U.S. Sugar) addresses the Clewiston Mill.

A. VE TESTING FOR BAGASSE HANDLING SYSTEM DUST COLLECTOR

1. Deviations from Applicable Requirements

A construction permit was issued on November 4, 2004, that authorized modification of the Bagasse Handling System at the Clewiston Mill (Permit No. 0510003-024-AC/PSD-FL-333A). A total of five bagasse dust collectors are authorized to be installed under this permit. To date, U.S. Sugar has installed two of the bagasse dust collectors authorized under the permit. These dust collectors are depicted on Attachment USS-EU12-I1 of the Title V application. One is a dust collector controlling fugitive dust emissions from the bagasse conveyor coming from the "B" Tandem, where the bagasse drops onto the C1 conveyor. The second is where bagasse is transferred from the C4 conveyor to the belt conveyor feeding the outside bagasse storage pile.

Section 3, Subsection B, Specific Condition No. 4 of the permit requires that initial visible emissions (VE) compliance testing be conducted within 180 days of completion of construction. The required VE testing was conducted on the transfer point from the C4 conveyor. However, VE testing was not conducted on the "B" Tandem conveyor transfer point. An attempt was made to conduct VE testing on this baghouse, but due to its location, VE testing could not be conducted. A subsequent follow-up visit by the professional engineer of record (David A. Buff, Golder Associates Inc.) confirmed that the baghouse was located inside the partially enclosed Boiler Building, and indeed discharged inside the partial enclosure. A valid VE reading is not feasible at this location.

2. Compliance Plan

U.S. Sugar submitted an application in June 2006 to the FDEP requesting that the bagasse handling system dust collectors be eliminated. The dust collectors have failed due to severe corrosion due to the high moisture bagasse and high humidity conditions the dust collectors operated under. The June 2006 application described a number of improvements being made to the biomass handling system, in lieu of installing the additional dust collectors authorized under permit no. 0510003-024-AC/PSD-FL-333A.. U.S. Sugar is requesting, through this Title V renewal application, that the bagasse dust collectors be removed from the construction and Title V permit.

B. INSTALLATION OF DUST COLLECTORS FOR BAGASSE HANDLING SYSTEM

1. Deviations from Applicable Requirements

A construction permit was issued on November 4, 2004, that authorized modification of the Bagasse Handling System at the Clewiston Mill (Permit No. 0510003-024-AC/PSD-FL-333A). A total of five bagasse dust collectors are authorized to be installed under this permit. U.S. Sugar has to date installed two of the bagasse dust collectors authorized under the permit. These dust collectors are depicted on Attachment USS-EU12-I1 of the Title V application. One is a dust collector controlling fugitive dust emissions from the bagasse conveyor coming from the "B" Tandem, where the bagasse drops onto the C1 conveyor. The second is where bagasse is transferred from the C4 conveyor to the belt conveyor feeding the outside bagasse storage pile. The remaining three dust collectors have not yet been installed.

Section 3, Subsection B, Specific Condition No. 4 of the permit requires that initial visible emissions (VE) compliance testing be conducted within 180 days of completion of construction. The required VE testing was conducted on the transfer point from the C4 conveyor. VE testing on the B Tandem conveyor transfer point is addressed in item 1 of this Compliance Report and Plan.

2. Compliance Plan

U.S. Sugar submitted an application in June 2006 to the FDEP requesting that the bagasse handling system dust collectors be eliminated. The dust collectors have failed due to severe corrosion due to the high moisture bagasse and high humidity conditions the dust collectors operated under. The June 2006 application described a number of improvements being made to the biomass handling system, in lieu of installing the additional dust collectors authorized under permit no. 0510003-024-AC/PSD-FL-333A.. U.S. Sugar is requesting, through this Title V renewal application, that the bagasse dust collectors be removed from the construction and Title V permit.

C. INSTALLATION OF WHITE SUGAR DRYER AND COMPLIANCE TESTING

1. Deviations from Applicable Requirements

A construction permit was issued on February 11, 2005, that authorized installation of a new white sugar dryer (Dryer No. 2) at the Clewiston Mill (Permit No. 0510003-026-AC/PSD-FL-346). The construction permit requires that initial VE and PM compliance testing be conducted within 60 days after achieving the maximum sugar processing rate, but not later than 180 days after initial startup of the system. The emissions unit began operating in the fall 2006, and initial compliance testing was performed on December 7, 2005.

The compliance testing resulted in PM emissions of 9.9 lb/hr, which is greater than the PM emission limit of 4.2 lb/hr. Subsequent to the initial stack testing in December 2005, U.S. Sugar investigated the potential causes of the higher than expected emissions. This included the following activities and engineering issues that were discovered:

- Discussions with the scrubber manufacturer, which ultimately proved to be unsatisfactory.
- October 2005- The original scrubber was designed for 104,500 acfm at the inlet, but the air flow through the dryer was actually about 95,000 acfm at the inlet, which also resulted in a lower than normal pressure drop. To correct this, Entoleter added a blanking plate to the vane cage within the scrubber to increase velocity and raise the pressure drop. The vane cage is located on the inlet of the scrubber and is basically a cage with vanes that distribute the air flow and creates the proper air flow in the scrubber (see Appendix A for illustration). About 25 percent of the area of the vane cage was blocked to increase the air velocity. The scrubber now operates at 8- to 10-inch pressure drop, and the scrubber is not discharging the large amounts of sugar seen at startup.
- October 2005- The outlet of the cyclones was identified as being designed too small. As a result, the cyclones could not handle all of the air flow from the dryer. Therefore, at Entoleter's suggestion, a bypass duct around the cyclones was installed to route about 25 percent of the air flow directly to the wet scrubber.
- January 2006- Additional diagnostic testing was performed on the dryer in January 2006. However, PM emissions were not improved over the initial compliance testing.

- February 2006- Blanking plates were also needed at the radial liquid separator (de-entrainer or mist eliminator) to increase the velocity at this point. The liquid separator acts to remove the PM-laden droplets from the gas stream. The ideal velocity through the de-entrainer is 7,200 to 7,500 feet per minute (fpm). But at 97,000 acfm at the outlet (flow at initial test), the velocity was only about 6,700 fpm through the de-entrainer. U.S. Sugar installed these blanking plates.

- May 2006- Entoleter believed the scrubber water flow rate was too low. Without adequate water flow, the maximum PM removal efficiency of the scrubber cannot be obtained. Therefore, the scrubber water flow rate was increased to about 750 gpm. The May 2006 tests were conducted with the higher scrubber water flow rate, but the PM results did not improve.

- May 2006- The low scrubber recirculation water temperature was investigated, but this was not believed to be an issue. No changes were made to that system.

- May 2006- U.S. Sugar hires two scrubber experts (Winkler APC, LLC and David Taub, a former vice-president of Entoleter) to help identify the causes and potential solutions to the high PM emissions.

- June 2006- U.S. Sugar files lawsuit against Entoleter over design flaws.

- June 2006- U.S. Sugar has investigated the feasibility of installing a mist eliminator at the outlet of the wet scrubber. U.S. Sugar also contacted Mr. Taub, a former vice-president of Entoleter to obtain his professional opinion. It was his opinion that because the outlet of the wet scrubber is configured vertically (instead of a horizontal outlet), a mist eliminator would not be effective due to the cyclonic flow exiting the scrubber. Also, due to the existing scrubber system geometry and space limitations, it is not practical to reconfigure the outlet of the scrubber.

- June 2006- U.S. Sugar submits an air construction permit application to FDEP to revise the PM emission limit for the WSD No. 2.

- August 2006- Additional PM testing was performed subsequent to modifications to the scrubber. Preliminary results indicate a significant improvement over previous results, although still above the PM emission limit. Carryover of sugar-laden droplets containing dissolved sugar out of the scrubber appear to still be a problem.

2. Compliance Plan

U.S. Sugar will continue discussions with FDEP on resolving the permitting issues. Pending full evaluation of the August test results, the June 2006 application may be revised to request less of an increase in the PM emission limit. Formal compliance testing will be conducted to confirm the August 2006 in-house testing. U.S. Sugar will continue to work with FDEP to execute a consent order.

D. DUST COLLECTOR FOR LIMESTONE SILO AT MOLASSES PLANT

1. Deviations from Applicable Requirements

A construction permit was issued on September 6, 2005, that authorized construction of a Limestone Silo with a baghouse at the Molasses Plant at the Clewiston Mill (Permit No. 0510003-033-AC). Specific Conditions No. 13 through 15 of the permit requires that initial visible emissions (VE) compliance testing be conducted within 60 days of completion of construction. The required VE testing has not been conducted because there has only been one delivery of limestone to date.

2. Compliance Plan

Compliance testing for VE will be performed within 60 days of the start of the upcoming crop season (expected to start in early October). When a limestone delivery is scheduled, a VE test date will be set, and FDEP will be notified.

E. DUST COLLECTORS FOR LIME UNLOADING AND STORAGE

1. Deviations from Applicable Requirements

A construction permit was issued on January 20, 2006, that authorized construction of a two lime silos and a lime collection bin, each with a baghouse for dust control at the Clewiston Mill (Permit No. 0510003-034-AC). Section 3.A., Specific Condition No. 4 of the permit requires that initial visible emissions (VE) compliance testing be conducted within 60 days of achieving permitted capacity, but not later than 180 days after initial operation. The required VE testing has not been conducted because the emissions unit has not yet begun operation.

2. Compliance Plan

Compliance testing for VE will be performed within 60 days of achieving permitted capacity, but not later than 180 days after initial operation. Initial operation is expected in early October. Once a test date is scheduled, FDEP will be notified.

EMISSION UNIT 1

BOILER #1

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Boiler No. 1

3. Emissions Unit Identification Number: **001**

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

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
Vibrating grate boiler fired by carbonaceous fuel and No. 2 fuel oil with a maximum sulfur content of 0.05% by weight.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Joy Turbulaire Impingement Scrubber, Size 125, Type D**
2. Control Device or Method Code(s): **001**

EMISSIONS UNIT INFORMATION
Section [1]
Boiler No. 1

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **245,000 lb/hr steam**	
3. Maximum Heat Input Rate: **495** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on 1-hour maximum steam rate (above) for carbonaceous fuel firing. Maximum 24-hour average firing for carbonaceous fuel is 936 MMBtu/hr, corresponding to 500,000 lb/hr steam. Maximum for No. 2 fuel oil is 562 MMBtu/hr. The permitted annual steam production limit is 3,6135 x 109 lb of steam per consecutive 12-month period, equivalent to 6,767,100 MMBtu per year.**	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-1**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **213** feet	7. Exit Diameter: **8.0** feet
8. Exit Temperature: **150°F**	9. Actual Volumetric Flow Rate: **250,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; All boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **68.75**	5. Maximum Annual Rate: **602,250**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.09 (dry basis)**	8. Maximum % Ash: **8.4 (dry basis)**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Based on 495 MMBtu/hr and 3,600 Btu/lb wet bagasse. Wet bagasse averages approximately 52-percent moisture.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Distillate oil; Grades 1 and 2.**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **0.963**	5. Maximum Annual Rate: **6,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Maximum hourly and annual rates based on 130 MMBtu/hr and 6,000,000 gallons of No. 2 fuel oil per year. Also includes facility generated on-spec used oil and up to 500 cubic yards per season of petroleum contaminated soils. Combined fuel oil usage in Boiler Nos. 1, 2, and 4 limited to 6,000,000 gal/yr. Permit No. 0510003-039-AC.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	001		EL
PM10	001		NS
SO2	001		EL
NOx			NS
CO			NS
VOC			NS
SAM			NS
PB	001		NS
HAPs (Total Hazardous Air Pollutants)			NS
H001 (Acetaldehyde)			NS
H006 (Acrolein)			NS
H017 (Benzene)			NS
H021 (Beryllium)	001		NS
H052 (p-cresol)			NS
H058 (Dibenzofurans)			NS
H095 (Formaldehyde)			NS
H106 (Hydrogen Chloride)			NS
H114 (Mercury)	001		NS
H132 (Naphthalene)			NS
H144 (Phenol)			NS
H151 (POMs)			NS
H163 (Styrene)			NS
H169 (Toluene)			NS

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **123.8** lb/hour **542.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.25 lb/MMBtu** Reference: **Permit No. 0510003-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Bagasse: 495 MMBtu/hr x 0.25 lb/MMBtu = 123.75 lb/hr** **123.75 lb/hr x 8,760 hr/yr x ton/2000 lb = 542.0 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Maximum emissions representative of bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.25 lb/MMBtu**	4. Equivalent Allowable Emissions: **123.8** lb/hour **542.0** tons/year
5. Method of Compliance: **EPA Method 5 or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **13.0** lb/hour **41.7** tons/year
5. Method of Compliance: **EPA Method 5 or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.410(1)(b)2, F.A.C., and Permit No. 0510003-027-AC. Emissions representative of fuel oil firing. Annual emissions based on 6,000,000 gallons per any consecutive 12 months.**	

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **115.1** lb/hour **504.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **93% of PM** Reference: **Test data**	7. Emissions Method Code: **1**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **123.8 lb/hr x 0.93 = 115.1 lb/hr** **542.0 TPY x 0.93 = 504.1 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Maximum emissions representative of bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **29.7** lb/hour **130.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu and 0.05% S Oil** Reference: **Industry Test Data**	7. Emissions Method Code: **1**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Bagasse: 495 MMBtu/hr x 0.06 lb/MMBtu = 29.7 lb/hr
Fuel Oil: 130 MMBtu/hr x 0.053 lb/MMBtu = 6.9 lb/hr

Annual: 29.7 lb/hr x 8,760 hr/yr x ton/2,000 lb= 130.1 TPY

11. Potential Fugitive and Actual Emissions Comment:

See Attachment UC-EU1-F1.11 for potential emissions due to fuel oil firing. Fuel oil emission factor of 0.053 lb/MMBtu is based on a density of 7.2 lb/gal, heating value of 135,000 Btu/gal, and sulfur content of 0.05 percent by weight.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% sulfur oil**	4. Equivalent Allowable Emissions: **6.9** lb/hour **22.2** tons/year
5. Method of Compliance: **Fuel oil analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Requested limit. Emissions representative of fuel oil firing. Annual emissions based on 6,000,000 gallons per any consecutive 12 months. See Attachment USS-EU1-F1.10 for calculations.**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Permit No. 0510003-017-AV and 0510003-036-AC, and Rule 62-296.410(1)(b)1., F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 6

1. Parameter Code: **PRS**	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Custom Design** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors pressure drop across wet scrubber. Monitored to ensure proper operation of scrubber. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **ITT Barton or equivalent** Model Number: **Flowco F500**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Permit No. 0510003-017-AV. Monitors fuel oil flow to Boiler No. 1. No serial # or installation date provided because monitors are routinely replaced to ensure optimum performance.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 6

1. Parameter Code: **Nozzle Pressure**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors wet scrubber spray nozzle pressure. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: **Steam Temp**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Preferred Instruments or equivalent** Model Number: **PCC-III Controller**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam temperature. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: **Steam Pressure**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam pressure. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621D** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam flow rate. Permit No. 0510003-017-AV.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU1-I1** ☒ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU1-I2** ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU1-I3** ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU1-I4** ☐ Previously Submitted, Date _____ ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1]
Boiler No. 1

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☒ Attached, Document ID: USS-EU1-IV1 ☐ Not Applicable
2. Compliance Assurance Monitoring ☒ Attached, Document ID: CAM Plan ☐ Not Applicable
3. Alternative Methods of Operation ☒ Attached, Document ID: USS-EU1-IV3 ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1]
Boiler No. 1

Additional Requirements Comment

ATTACHMENT USS-EU1-F1.11

FUTURE POTENTIAL EMISSIONS DUE TO FUEL OIL FIRING

Boiler No. 1

ATTACHMENT USS-EU1-F1.11
FUTURE POTENTIAL EMISSIONS DUE TO FUEL OIL FIRING BOILER NO. 1
U. S. Sugar Corporation Clewiston

Regulated Pollutant	No. 2 Fuel Oil Combustion					
	Emission Factor (lb/MMBtu)	Ref.	Activity Factor		Hourly Emissions (lb/hr)	Annual Emissions (TPY)
			Hourly[a] MMBtu/hr	Annual[b] MMBtu/yr		
Particulate Matter (PM)	0.015	1	130	834,000	1.9	6.2
Particulate Matter (PM_{10})	0.007	2	130	834,000	1.0	3.1
Sulfur dioxide (SO_2)	0.053	3	130	834,000	6.9	22.2
Nitrogen oxides (NO_x)	0.17	4	130	834,000	22.1	70.9
Carbon monoxide (CO)	0.037	1	130	834,000	4.8	15.4
Volatile Organic Compounds (VOC)	1.5E-03	1	130	834,000	0.2	0.62
Sulfuric acid mist (SAM)	0.0026	1	130	834,000	0.3	1.1
Lead (Pb)	9.0E-06	5	130	834,000	1.2E-03	3.8E-05
Beryllium (Be)	3.0E-06	5	130	834,000	3.9E-04	1.3E-05
Mercury (Hg)	3.0E-06	5	130	834,000	3.9E-04	1.3E-03

References:
1. Factors for No. 2 fuel oil combustion: AP-42 Tables 1.3-1 and 1.3-3 (9/98). For sulfuric acid mist, factor shown is for SO_3. Convert to H_2SO_4 by multiplying by 98/80. Factors were converted to lb/MMBtu by dividing by 135,000 Btu/gal (min).
   PM = 2 lb/1000 gal
   CO = 5 lb/1000 gal
   SO_3 = 5.7S lb/1000 gal, where S = 0.05 VOC = 0.2 lb/1000 gal
2. Factors for distillate fuel oil, PM_{10} is 50% of PM based on AP-42, Table 1.3-6 (9/98).
3. Based on stochiometric calculation: 7.2 lbs/gal; 135,000 Btu/gal (min); 0.05% sulfur.
4. Based on stack testing conducted on Boiler No. 1 and 2 on Feb. 10-11, 2006.
5. Factors for No. 2 fuel oil combustion, AP-42 Table 1.3-10 (9/98).

Footnotes:

[a] Based on maximum heat input due to No. 2 fuel oil combustion, from manufacturer specifications.

[b] Based on No. 2 fuel oil usage of 6,000,000 gallons per year and heating value of 139,000 Btu/gal (max).

ATTACHMENT USS-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Boiler No. 1

ATTACHMENT USS-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

62-296.410(1)(b), F.A.C.: Carbonaceous Fuel Burning Equipment

62-296.410(3), F.A.C.: Carbonaceous Fuel Burning Equipment

62-297.310(1), F.A.C.: General Compliance Test Requirements

62-297.310(2)(b), F.A.C.: General Compliance Test Requirements

62-297.310(3), F.A.C.: General Compliance Test Requirements

62-297.310(4), F.A.C.: General Compliance Test Requirements

62-297.310(5), F.A.C.: General Compliance Test Requirements

62-297.310(6), F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)3., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)4., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)5., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)9., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)10., F.A.C.: General Compliance Test Requirements

62-297.310(8), F.A.C.: General Compliance Test Requirements

62-297.401(1), F.A.C.: EPA Test Method 1

62-297.401(2), F.A.C.: EPA Test Method 2

62-297.401(3), F.A.C.: EPA Test Method 3

62-297.401(4), F.A.C.: EPA Test Method 4

62-297.401(5), F.A.C.: EPA Test Method 5

62-297.401(6), F.A.C.: EPA Test Method 6

62-297.401(6)(c), F.A.C.: EPA Test Method 6C

62-297.401(7), F.A.C.: EPA Test Method 7

62-297.401(7)(e), F.A.C.: EPA Test Method 7E

62-297.401(8), F.A.C.: EPA Test Method 8

62-297.401(9), F.A.C.: EPA Test Method 9

62-297.401(10), F.A.C.: EPA Test Method 10

62-297.401(18), F.A.C.: EPA Test Method 18

62-297.401(25)(a), F.A.C.: EPA Test Method 25A

40 CFR 63.1 – 63.16 – Subpart A – General Provisions: Boiler No. 1 is subject to the notification requirements of Subpart DDDDD.

40 CFR 63.7485 – Subpart DDDDD – Applicability: Boiler No. 1 is an industrial boiler of size > 10 MMBtu/hr located at a major source of HAPs.

40 CFR 63.7490 – Subpart DDDDD – Applicability: Boiler No. 1 is subject to the requirements of Subpart DDDDD for existing boilers.

40 CFR 63.7495 – Subpart DDDDD – Compliance Dates – Boiler No. 1 must meet notification requirements and comply by September 13, 2007.

40 CFR 63.7499 – Subpart DDDDD – Subcategories: Boiler No. 1 is in the large solid fuel subcategory.

40 CFR 63.7506 – Subpart DDDDD – Limited Requirements: Boiler No. 1 must only meet the notification requirements of 63.9(b) at this time.

40 CFR 63.7545 – Subpart DDDDD – Notifications: Boiler No. 1 must submit the required notification by March 12, 2005.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION GOLDER ASSOCIATES INC.

AUG - 4 2006

GAINESVILLE

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Authorized Representative:
Mr. Neil Smith, V.P. of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-036-AC
Boilers 1 and 2
Oil Burner Modifications
Hendry County, Florida

Final Air Permit No. 0510003-036-AC is enclosed authorizing modification of the oil firing systems for existing Boilers 1 and 2 at the Clewiston Sugar Mill and Refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/2/06 to the persons listed:

Mr. Neil Smith, USSC*
Mr. Don Griffin, USSC
Mr. Peter Briggs, USSC
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4

Clerk Stamp

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

Mary L Harvey (Clerk) 8/2/06 (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE:

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

Authorized Representative:
Mr. Neil Smith, V.P. of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-036-AC
Facility ID No. 0510003
Boilers 1/2, Oil Burner Modifications
Permit Expires: January 30, 2007

PROJECT AND LOCATION

This permit is a revision of original Permit No. 0510003-027-AC, which authorized replacement of the oil burner systems for Boilers 1 and 2 to fire distillate oil. The boilers operate at the existing Clewiston Sugar Mill and Refinery (SIC Nos. 2061 and 2062) located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

STATEMENT OF BASIS

This air pollution construction 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 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. This permit supplements all previously issued air construction and operation permits for the affected emissions units.

PERMIT CONTENT

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

Joe Kahn, Acting Director
Division of Air Resource Management

8/1/06
(Effective Date)

FACILITY DESCRIPTION

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

The primary air pollution sources are the six existing boilers firing bagasse and fuel oil. Particulate matter emissions are controlled with wet scrubbers for Boilers 1 through 4 and with electrostatic precipitators for Boilers 7 and 8. Other air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, conditioning silos with dust collectors, vacuum systems, sugar/starch bins, conveyors, and a packaging system. This project only affects the oil firing capabilities of Boilers 1 and 2 (Emissions Units 001 and 002).

FACILITY REGULATORY CLASSIFICATIONS

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.

RELEVANT DOCUMENTS

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

APPENDICES

The following Appendices are included as part of the permit in Section 4.

Appendix CF. Citation Format

Appendix GC. General Conditions

Appendix SC. Standard Conditions

1. Permitting Authority: The permitting authority for this project is the Florida Department of Environmental Protection's Bureau of Air Regulation. The mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.
3. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions units 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, the Florida Administrative Code, the Code of Federal Regulations, and any previously issued valid air permits. 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.]
4. 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.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
6. Source Obligation. [Rule 62-212.400(12), F.A.C.]
   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.
   (b) 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.
   (c) 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 exceeding its projected actual emissions, 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.
7. Title V Permit: This permit supersedes original Permit No. 0510003-027-AC. It authorizes construction of the permitted activities and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's South District Office. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

A. Boilers 1 and 2

This section of the permit addresses the following emissions units.

EU No.	Emission Unit Description
001	Boiler 1 is a traveling grate boiler with a maximum 1-hour steam production rate of 255,000 pounds per hour at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 125, Joy Turbulaire wet impingement scrubber. Exhaust gases exit at 150° F with an approximate flow rate of 201,000 acfm from a stack that is 8 feet in diameter and 213 feet tall.
002	Boiler 2 is a traveling grate boiler with a maximum 1-hour steam production rate of 230,000 pounds per hour at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 125, Joy Turbulaire wet impingement scrubber. Exhaust gases exit at 150° F with an approximate flow rate of 201,000 acfm from a stack that is 8 feet in diameter and 213 feet tall.

EQUIPMENT

1. Oil Firing Modifications: For each boiler, the permittee is authorized to replace the existing oil burners with new Peabody-type multi-stage combustion (MSC) burners (or equivalent) to fire distillate oil. In general, each burner consists of a steam-atomized center-fired oil gun, a flame scanner, an ignitor with flame proving rod, and an individual burner windbox with an electrically-operated modulating damper. The project also includes new combustion air fans with associated ductwork, new fuel oil pump sets, and new burner management systems. The burners shall be low NOx burners designed for a maximum NOx emission rate of 0.17 lb/MMBtu. Each boiler will have one oil burner with a maximum heat input rate of 130 MMBtu/hour. Based on a higher heating value of 135,000 Btu per gallon, the maximum distillate oil firing rate will be 963 gallons per hour per burner. The modified boilers are estimated to produce approximately 97,400 pounds of steam per hour from the sole firing of distillate oil. Bagasse will remain the primary fuel and distillate oil will be fired as a startup and supplemental fuel. This permit only addresses the oil firing aspects of these boilers. [Application; Design]

PERFORMANCE RESTRICTIONS

2. Oil Specification: Any oil fired in Boilers 1 and 2 shall be new No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. [Application; Design; Rule 62-212.400(12), F.A.C.]

3. Permitted Capacity on Oil: For each boiler, the maximum heat input rate from distillate oil is 130 MMBtu per hour. *{Permitting Note: The maximum steam production rate from firing 100% distillate oil is approximately 97,400 lb/hour.}* [Design; Rules 62-120.200(PTE) and 62-212.400(12), F.A.C.]

4. Restrictions on Oil: For each boiler, distillate oil firing shall not exceed 963 gallons per hour. For both boilers combined, distillate oil firing shall not exceed 6,000,000 gallons during any consecutive 12 months. The permittee shall install, calibrate, operate, and maintain an individual fuel oil flow meter with integrator. *{Permitting Note: The above hourly oil firing restriction supersedes the restriction of "1500" gallons per hour specified in Condition 4, Subsection IIIB, in Permit No. PSD-FL-272A.}* [Application; Design; Rule 62-212.400(12), F.A.C.]

EMISSIONS STANDARDS

5. Visible Emissions on Oil: Visible emissions shall not exceed 30% opacity based on a 6-minute average except for two minutes per hour during which the opacity shall not exceed 40% as determined by DEP Method 9. [Rule 62-296.410, F.A.C.]

6. Particulate Matter Emissions on Oil: Emissions of particulate matter shall not exceed 0.1 lb/MMBtu of heat input from the firing of distillate oil as determined by EPA Method 5. This standard is used to prorate the corresponding final standard if a compliance test is conducted while firing a combination of bagasse and

oil. A separate emissions performance test on oil only is not required. [Rule 62-296.410, F.A.C.]

EMISSIONS PERFORMANCE TESTING

7. Emissions Compliance Tests: This permit does not impose any new emissions compliance test requirements. The permittee shall continue to perform emissions compliance testing in accordance with the requirements of the current Title V air operation permit. [Rules 62-4.070(3) and 62-297.310, F.A.C.]

8. 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.]

RECORDS AND REPORTS

9. Oil Firing Records: The sulfur content of the fuel oil shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. For each fuel oil delivery, the permittee shall record and retain the following information: the date; gallons delivered; and a fuel oil analysis including the heating value in Btu/lb, the density in pounds/gallon, the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable. At least once during each federal fiscal year, the permittee shall have a representative sample analyzed in accordance with the specified methods. Results of the analysis shall be submitted to the Compliance Authority within 45 days of sampling. At the end of each month, the permittee shall read and record the amount indicated by the integrator on the fuel oil flow meter. The permittee shall calculate and record the amount of fuel oil fired during each month and during each consecutive 12-month period. Records shall be available for inspection within ten days following each month. [Rule 62-4.070(3), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

10. Previous Permits: This permit supplements all previously issued air construction and operation permits for this emissions unit. Except for changes specified in the above conditions, the unit remains subject to the conditions of all other valid air construction and operations permits. [Rule 62-4.070, F.A.C.]

Filename: 0510003-036-AC - Final Permit

CONTENTS

Appendix CF. Citation Format

Appendix GC. General Conditions

Appendix SC. Standard Conditions

CITATION FORMAT

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 CRF 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 (not applicable to project);
    b. Determination of Prevention of Significant Deterioration (not applicable to project); and
    c. Compliance with New Source Performance Standards (not applicable to project).

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.

STANDARD CONDITIONS

Unless otherwise specified by permit, the following conditions apply to all emissions units and activities.

EMISSIONS AND CONTROLS

1. 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.]

2. 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.]

3. 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.]

4. 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.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee 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.]

6. 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.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

8. 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.]

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

RECORDS AND REPORTS

10. 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. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

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

FINAL DETERMINATION

PERMITTEE

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

Authorized Representative:

Mr. Neil Smith, V.P. of Sugar Processing Operations

PERMITTING AUTHORITY

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

PROJECT

Project No. 0510003-036-AC (modification of original Permit No. 0510003-027-AC)
U. S. Sugar Corporation – Clewiston Sugar Mill
Boilers 1 and 2, Oil Burner Modifications

The United States Sugar Corporation operates the existing Clewiston Sugar Mill and Refinery (SIC Nos. 2061 and 2062) located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. This permitting action revises original Permit No. 0510003-027-AC for the following: identify installation of only one Peabody-type multi-stage combustion (MSC) burner on each boiler; specify the maximum burner capacity as 130 MMBtu/hour (963 gallons per hour); identify the maximum NOx emissions rate of 0.17 lb/MMBtu; reduce the annual distillate oil firing rate for each boiler from 3.5 to 3.0 million gallons per year; and for operational flexibility, cap the combined fuel firing of Boilers 1 and 2 to 6.0 million gallons per year instead of 3.0 million gallons per year per boiler.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on June 16, 2006. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on June 29, 2006. The Department received the proof of publication on July 19, 2006. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

No comments on the Draft Permit were received from the public, the Department's South District Office, the EPA Region 4 Office, the National Park Service, or the applicant.

CONCLUSION

The final action of the Department is to issue the permit with only minor changes to typographical errors.

ATTACHMENT USS-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 1

ATTACHMENT USS-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 1 is designed to operate while combusting carbonaceous fuel alone at a maximum heat input rate of 495 MMBtu/hr (maximum 24-hour average); or, No. 2 fuel oil alone at a maximum fuel oil heat input rate of 130 MMBtu/hr; or, a combination of carbonaceous fuel and No. 2 fuel oil. The boiler may also burn small quantities of petroleum-contaminated soils (up to 500 cubic yards per season) and facility-generated, on-specification used oil. The maximum sulfur content in the fuel oil is limited to 0.05 percent by weight. This unit has no limits on hours of operation and may operate for 8,760 hours per year.

EMISSION UNIT 2

BOILER #2

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

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

3. Emissions Unit Identification Number: **002**

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

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **Vibrating grate boiler fired by carbonaceous fuel and No. 2 fuel oil with a maximum sulfur content of 0.05% by weight.**

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Joy Turbulair Impingement Scrubber, Size 125, Type D**	
2. Control Device or Method Code(s): **001**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **215,000 lb/hr steam**	
3. Maximum Heat Input Rate: **447** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on 1-hour maximum steam rate (above) for carbonaceous fuel of 215,000 lb/hr steam. Maximum heat input for No. 2 fuel oil is 130 MMBtu/hr and 6,000,000 gal/yr.**	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-2**	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **213** feet	7. Exit Diameter: **8.0** feet
8. Exit Temperature: **150** °F	9. Actual Volumetric Flow Rate: **250,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; All boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **62.08**	5. Maximum Annual Rate: **543,850**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.09 (dry basis)**	8. Maximum % Ash: **8.4 (dry basis)**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Based on 447 MMBtu/hr and 3,600 Btu/lb wet bagasse. Wet bagasse averages approximately 52-percent moisture.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; Distillate Oil; Grades 1 and 2.**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **0.963**	5. Maximum Annual Rate: **6,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Maximum hourly and annual rates based on 130 MMBtu/hr and 6,000,000 gallons of No. 2 fuel oil per year. Also includes facility generated on-spec used oil and up to 500 cubic yards per season of petroleum contaminated soils. Combined fuel oil usage in Boiler Nos. 1, 2, and 4 limited to 6,000,000 gal/yr. Permit No. 0510003-039-AC.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	001		EL
PM10	001		NS
SO2	001		EL
NOx			NS
CO			NS
VOC			NS
SAM			NS
PB	001		NS
HAPs (Total Hazardous Air Pollutants)			NS
H001 (Acetaldehyde)			NS
H006 (Acrolein)			NS
H017 (Benzene)			NS
H021 (Beryllium)	001		NS
H052 (p-cresol)			NS
H058 (Dibenzofurans)			NS
H095 (Formaldehyde)			NS
H106 (Hydrogen Chloride)			NS
H114 (Mercury)	001		NS
H132 (Naphthalene)			NS
H144 (Phenol)			NS
H151 (POMs)			NS
H163 (Styrene)			NS
H169 (Toluene)			NS

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **111.8** lb/hour **490** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.25 lb/MMBtu** Reference: **Permit No. 0510003-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Bagasse: 447 MMBtu/hr x 0.25 lb/MMBtu = 111.8 lb/hr** **111.8 lb/hr x 8,760 hr/yr x ton/2,000 lb = 490 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Maximum emissions representative of bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.25 lb/MMBtu**	4. Equivalent Allowable Emissions: **111.8** lb/hour **490** tons/year
5. Method of Compliance: **EPA Method 5 or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **13.0** lb/hour **41.7** tons/year
5. Method of Compliance: **EPA Method 5 or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.410(1)(b)2, F.A.C., and Permit No. 0510003-017-AV. Emissions representative of fuel oil firing. Annual emissions based on 6,000,000 gallons per any consecutive 12 months.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **104.0** lb/hour **455.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **93% of PM** Reference: **Test data**	7. Emissions Method Code: **1**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **111.8 lb/hr x 0.93 = 104.0 lb/hr** **490 TPY x 0.93 = 455.7 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Maximum emissions representative of bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.82** lb/hour **117.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu and 0.05% S oil.** Reference: **Industry test data**	7. Emissions Method Code: **1**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Bagasse: 447 MMBtu/hr x 0.06 lb/MMBtu = 26.82 lb/hr
Fuel Oil: 130 MMBtu/hr x 0.053 lb/MMBtu = 6.9 lb/hr

Annual: 26.82 lb/hr x 8,760 hr/yr x ton/2,000 lb = 117.5 TPY

11. Potential Fugitive and Actual Emissions Comment:
Fuel oil based on 0.05% sulfur oil. See Attachment UC-EU2-F1.11 for potential emissions due to fuel oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% sulfur oil**	4. Equivalent Allowable Emissions: **6.9** lb/hour **22.2** tons/year
5. Method of Compliance: **Fuel oil analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Requested limit. Emissions representative of fuel oil firing. Annual emissions based on 6,000,000 gallons per any consecutive 12 months. See Attachment USS-EU2-F1.11 for calculations.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE30**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Permit Nos. 0510003-017-AV and 0510003-036-AC, and Rule 62-296.410(1)(b)1., F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 6

1. Parameter Code: **PRS**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Custom Design** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors pressure drop across wet scrubber. Monitored to ensure proper operation of scrubber. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **ITT Barton or equivalent** Model Number: **Flowco F500** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Permit No. 0510003-017-AV. Monitors fuel oil flow to Boiler No. 2. No serial # or installation date provided because monitors are routinely replaced to ensure optimum performance.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 6

1. Parameter Code: **Nozzle Pressure**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors wet scrubber spray nozzle pressure. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: **Steam Temp**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Preferred Instruments or equivalent** Model Number: **PCC-III Controller** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam temperature. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: **Steam Pressure**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam pressure. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621D** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam flow rate. Permit No. 0510003-017-AV.**	

EMISSIONS UNIT INFORMATION
Section [2]
Boiler No. 2

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USS-EU2-I1** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USS-EU2-I2** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USS-EU2-I3** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USS-EU2-I4** ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

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

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

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

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

   ☒ Not Applicable

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

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

EMISSIONS UNIT INFORMATION
Section [2]
Boiler No. 2

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))	
☐ Attached, Document ID: _____	☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)	
☐ Attached, Document ID: _____	☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	
☐ Attached, Document ID: _____	☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements	
☒ Attached, Document ID: **USS-EU2-IV1**	☐ Not Applicable
2. Compliance Assurance Monitoring	
☒ Attached, Document ID: **CAM Plan**	☐ Not Applicable
3. Alternative Methods of Operation	
☒ Attached, Document ID: **USS-EU2-IV3**	☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)	
☐ Attached, Document ID: _____	☒ Not Applicable

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

EMISSIONS UNIT INFORMATION
Section [2]
Boiler No. 2

Additional Requirements Comment

ATTACHMENT USS-EU2-F1.11

FUTURE POTENTIAL EMISSIONS DUE TO FUEL OIL FIRING

Boiler No. 2

ATTACHMENT USS-EU2-F1.11
FUTURE POTENTIAL EMISSIONS DUE TO FUEL OIL FIRING, BOILER NO. 2,
U. S. Sugar Corporation Clewiston

Regulated Pollutant	No. 2 Fuel Oil Combustion					
	Emission Factor (lb/MMBtu)	Ref.	Activity Factor		Hourly Emissions (lb/hr)	Annual Emissions (TPY)
			Hourly[a] MMBtu/hr	Annual[b] MMBtu/yr		
Particulate Matter (PM)	0.015	1	130	834,000	1.9	6.2
Particulate Matter (PM_{10})	0.007	2	130	834,000	1.0	3.1
Sulfur dioxide (SO_2)	0.053	3	130	834,000	6.9	22.2
Nitrogen oxides (NO_x)	0.17	4	130	834,000	22.1	70.9
Carbon monoxide (CO)	0.037	1	130	834,000	4.8	15.4
Volatile Organic Compounds (VOC)	1.5E-03	1	130	834,000	0.2	0.62
Sulfuric acid mist (SAM)	0.0026	1	130	834,000	0.3	1.1
Lead (Pb)	9.0E-06	5	130	834,000	1.2E-03	3.8E-05
Beryllium (Be)	3.0E-06	5	130	834,000	3.9E-04	1.3E-05
Mercury (Hg)	3.0E-06	5	130	834,000	3.9E-04	1.3E-03

References:

1. Factors for No. 2 fuel oil combustion: AP-42 Tables 1.3-1 and 1.3-3 (9/98). For sulfuric acid mist, factor shown is for SO_3. Convert to H_2SO_4 by multiplying by 98/80. Factors were converted to lb/MMBtu by dividing by 135,000 Btu/gal (min).
   PM = 2 lb/1000 gal
   CO = 5 lb/1000 gal
   SO_3 = 5.7S lb/1000 gal, where S = 0.05 VOC = 0.2 lb/1000 gal
2. Factors for distillate fuel oil, PM_{10} is 50% of PM based on AP-42, Table 1.3-6 (9/98).
3. Based on stochiometric calculation: 7.2 lbs/gal; 135,000 Btu/gal (min); 0.05% sulfur.
4. Based on stack testing conducted on Boiler No. 1 and 2 on Feb. 10-11, 2006.
5. Factors for No. 2 fuel oil combustion, AP-42 Table 1.3-10 (9/98).

Footnotes:

[a] Based on maximum heat input due to No. 2 fuel oil combustion, from manufacturer specifications.

[b] Based on No. 2 fuel oil usage of 6,000,000 gallons per year and heating value of 139,000 Btu/gal (max).

ATTACHMENT USS-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 2

ATTACHMENT USS-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 2 is designed to operate while combusting carbonaceous fuel alone at a maximum heat input rate of 447 MMBtu/hr (maximum 24-hour average) or No. 2 fuel oil alone at a maximum fuel oil heat input rate of 130 MMBtu/hr. The boiler may also burn small quantities of petroleum-contaminated soils (up to 500 cubic yards per season) and facility-generated, on-specification used oil. The maximum sulfur content in the fuel oil is limited to 0.05 percent by weight. This unit has no limits on hours of operation and may operate for 8,760 hours per year.

EMISSION UNIT 3

BOILER #4

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Boiler No. 4

3. Emissions Unit Identification Number: **009**

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

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    Traveling grate boiler fired by carbonaceous fuel and fuel oil with a maximum sulfur content of 0.05 percent by weight. Fuel oil can include facility-generated, on-specification used oil.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Joy Turbulaire Impingement Scrubber, Size 200, Type D**
2. Control Device or Method Code(s): **001**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **300,000 lb/hr steam**	
3. Maximum Heat Input Rate: **633** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rate based on 1-hour maximum steam rate of 300,000 lb/hr for carbonaceous fuel firing. The maximum permitted 24-hour average heat input rate for firing carbonaceous fuel is 600 MMBtu/hr, and the maximum permitted 1-hour average heat input rate for firing No. 2 fuel oil is 326 MMBtu/hr (Permit Nos. 0510003-018-AC and 0510003-039-AC). Maximum annual heat input is limited to 2,880,000 MMBtu/yr (Permit No. 0510003-010/PSD-FL-272A).**	

EMISSIONS UNIT INFORMATION
Section [3]
Boiler No. 4

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-4**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **8.2** feet
8. Exit Temperature: **160** °F	9. Actual Volumetric Flow Rate: **281,000** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on test data.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Bagasse; All boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **87.92**	5. Maximum Annual Rate: **400,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.24 (dry)**	8. Maximum % Ash: **8.4 (dry basis)**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Based on 633 MMBtu/hr and 3,600 Btu/lb wet bagasse. Annual rate is maximum allowable from Permit No. 0510003-010-AC/PSD-FL-272A, equivalent to 2,880,000 MMBtu/yr @ 3,600 Btu/lb for wet bagasse. Bagasse may include incidental amounts of on-specification used oil.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; Industrial; Distillate Oil; Grades 1 and 2**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **2.417**	5. Maximum Annual Rate: **6,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Maximum hourly and annual rates based on 326 MMBtu/hr and 6,000,000 gallons of fuel oil per year (Permit Nos. 0510003-018-AC and 0510003-039-AC). Includes combustion of facility-generated, on-specification used oil. Annual rate represents cap for Boiler Nos. 1, 2, and 4 combined.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	001		EL
PM_{10}	001		NS
SO_2	001		EL
NO_x			EL
CO			EL
VOC			EL
SAM			NS

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **95** lb/hour **216** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.15 lb/MMBtu** Reference: **Permit No. 0510003-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emission (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Bagasse: 633 MMBtu/hr x 0.15 lb/MMBtu = 95 lb/hr

Annual emissions based on heat input rate of 2,880,000 MMBtu during consecutive any 12 months.

2,880,000 MMBtu/yr x 0.15 lb/MMBtu x 1 ton/2,000 lb = 216 ton/yr

Fuel Oil:
326 MMBtu/hr x 0.1 lb/MMBtu = 32.6 lb/hr
6,000,000 gal/yr x 139,000 Btu/gal = 834,000 MMBtu/yr
834,000 MMBtu/yr x 0.1 lb/MMBtu x 1 ton/2,000 lb = 41.7 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Maximum emissions representative of bagasse firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **95** lb/hour **216** tons/year
5. Method of Compliance: **EPA Method 5 or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.10 lb/MMBtu**	4. Equivalent Allowable Emissions: **32.6** lb/hour **41.7** tons/year
5. Method of Compliance: **EPA Method 5 or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.406, F.A.C. Emissions representative of fuel oil firing. Annual emissions based on 6,000,000 gallons per any consecutive 12 months.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.0** lb/hour **86.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu for bagasse** Reference: **Permit No. 0510003-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emission (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: **Bagasse – 633 MMBtu/hr x 0.06 lb/MMBtu = 38.0 lb/hr**
Fuel Oil -- 326 MMBtu/hr x 0.0533 lb/MMBtu = 17.4 lb/hr

Annual: **Bagasse – 2,880,000 MMBtu/hr x 0.06 lb/MMBtu ÷ 2,000 lb/ton = 86.4 TPY**
Fuel Oil -- 6,000,000 gal/yr x 139,000 Btu/gal = 834,000 MMBtu/yr
834,000 MMBtu/yr x 0.0533 lb/MMBtu ÷ 2,000 lb/ton = 22.2 TPY

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
Factors based on carbonaceous fuel firing. Fuel oil sulfur content limited to 0.05 percent: 7.2 lb/gal x 0.05/100 lb S/lb oil x 2 lb SO_2/lb S ÷ 135,000 Btu/gal = 0.0533 lb SO_2/MMBtu.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **38** lb/hour **86.4** tons/year
5. Method of Compliance: **EPA Method 6, 6c, or 8.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Emissions representative of bagasse firing only. Based on carbonaceous fuel and maximum heat input of 2,880,000 MMBtu during any consecutive 12 months.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% S oil**	4. Equivalent Allowable Emissions: **17.4** lb/hour **22.2** tons/year
5. Method of Compliance: **Fuel oil analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions representative of fuel oil firing. Hourly emissions based on firing 2,417 gal/hr. Annual emissions based on 6,000,000 gallons per any consecutive 12 months.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 126.6 lb/hour 288 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.20 lb/MMBtu Reference: Permit Nos. 0510003-017-AV and 0510003-018-AC.	7. Emissions Method Code: 0
8.a. Baseline Actual Emission (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Bagasse: 633 MMBtu/hr x 0.20 lb/MMBtu = 126.6 lb/hr

Annual emissions based on heat input rate of 2,880,000 MMBtu during any consecutive 12 months.

2,880,000 MMBtu/yr x 0.20 lb/MMBtu x 1 ton/2,000 lb = 288.0 TPY

Fuel Oil:
130 MMBtu/hr x 0.20 lb/MMBtu = 26.0 lb/hr
834,000 MMBtu/yr x 0.20 lb/MMBtu x 1 ton/2,000 lb = 83.4 TPY

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
Maximum emissions representative of bagasse firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **126.6** lb/hour **288** tons/year
5. Method of Compliance: **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Based on carbonaceous fuel firing and maximum heat input of 2,880,000 MMBtu during any consecutive 12 months.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **26.0** lb/hour **83.4** tons/year
5. Method of Compliance: **EPA Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-018-AC. Based on firing of No. 2 distillate fuel oil.**	

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4,114.5** lb/hour **9,360.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6.5 lb/MMBtu** Reference: **Permit No. 0510003-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emission (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

633 MMBtu/hr x 6.5 lb/MMBtu = 4,114.5 lb/hr

Annual emissions based on heat input rate of 2,880,000 MMBtu during any consecutive 12 months.

2,880,000 MMBtu/yr x 6.5 lb/MMBtu x 1 ton/2,000 lb = 9,360 TPY

11. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum emissions representative of bagasse firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **6.5 lb/MMBtu**	4. Equivalent Allowable Emissions: **4,114.5** lb/hour **9,360.0** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **316.5** lb/hour **720** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.50 lb/MMBtu** Reference: **Permit No. 0510003-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emission (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

633 MMBtu/hr x 0.50 lb/MMBtu = 316.5 lb/hr

Annual emissions based on heat input rate of 2,880,000 MMBtu during any consecutive 12 months.

2,880,000 MMBtu/yr x 0.50 lb/MMBtu x 1 ton/2,000 lb = 720 TPY

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
Maximum emissions representative of bagasse firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.50 lb/MMBtu**	4. Equivalent Allowable Emissions: **316.5** lb/hour **720** tons/year
5. Method of Compliance: **EPA Method 18 and 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-017-AV. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Applies to carbonaceous fuel burning only. Permit 0510003-017-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Applies to fuel oil burning only. Permit No. 0510003-018-AC.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 9

1. Parameter Code: **PRS**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Custom Design** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors pressure drop across wet scrubber. Monitored to ensure proper operation of scrubber. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 2 of 9

1. Parameter Code: **Nozzle PRESSURE**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors wet scrubber spray nozzle pressure. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 9

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Rosemount, Inc., or equivalent** Model Number: **8711/8712** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors wet scrubber liquid flow rate. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 4 of 9

1. Parameter Code: **Steam TEMP**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Preferred Instruments or equivalent** Model Number: **PCC-III Controller** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam temperature. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 5 of 9

1. Parameter Code: **Steam PRESSURE**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621G** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam pressure. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 6 of 9

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **ABB-Kent Taylor or equivalent** Model Number: **621D** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors steam flow rate. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 7 of 9

1. Parameter Code: O_2	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Rosemount Analytical, Inc., or equivalent** Model Number: **3000** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors flue gas oxygen content. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor 8 of 9

1. Parameter Code: **CO**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Thermo Environmental Instruments, Inc., or equivalent** Model Number: **48C** Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors flue gas carbon monoxide content. Permit No. 0510003-017-AV.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 9 of 9

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule	☒ Other
4. Monitor Information... Manufacturer: **ITT Barton or equivalent** Model Number: **Flowco F500**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitors fuel oil flow to Boiler No. 4. No serial number or installation date provided because monitors are routinely replaced to ensure optimum performance. Permit No. 0510003-017-AV.**	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule	☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU3-I1** ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU3-I2** ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU3-I3** ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU3-I4** ☐ Previously Submitted, Date _____ ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☒ Attached, Document ID: USS-EU3-IV1 ☐ Not Applicable
2. Compliance Assurance Monitoring ☒ Attached, Document ID: CAM Plan ☐ Not Applicable
3. Alternative Methods of Operation ☒ Attached, Document ID: USS-EU3-IV3 ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [3]
Boiler No. 4

Additional Requirements Comment

ATTACHMENT USS-EU3-I2

FUEL ANALYSIS

Boiler No. 4

ATTACHMENT USS-EU3-I2
BOILER NO. 4 FUEL ANALYSIS

Parameter	Fuel	
	Carbonaceous Fuel [a]	No. 2 Fuel Oil (0.05% S max)
Density (lb/gal)	--	6.83 [c]
Approximate Heating Value (Btu/lb)	3,600 [b]	19,910 [c]
Approximate Heating Value (Btu/gal)	--	135,000 [c]
Ultimate Analysis (dry basis):		
Carbon	48.1%	84.7% [d]
Hydrogen	5.9%	15.3% [d]
Nitrogen	0.35%	0.18% [d]
Oxygen	40.9%	0.38% [d]
Sulfur	0.08% - 0.24%	0.05% [e]
Ash/Inorganic	0.87% - 8.4%	0.06% [c]
Moisture	49% - 55%	0.51% [c]

Footnotes:

[a] Source: Clewiston Mill fuel analysis averages.

[b] Wet basis for bagasse. Represents normal minimum.

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

[d] Source: fuel analysis from Coastal Fuels Marketing, Inc. (9/21/00).

[e] Proposed maximum.

ATTACHMENT USS-EU3-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Boiler No. 4

ATTACHMENT USS-EU3-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

62-296.410(2)(b), F.A.C.: Carbonaceous Fuel Burning Equipment

62-296.410(3), F.A.C.: Carbonaceous Fuel Burning Equipment

62-297.310(1), F.A.C.: General Compliance Test Requirements

62-297.310(2)(b), F.A.C.: General Compliance Test Requirements

62-297.310(3), F.A.C.: General Compliance Test Requirements

62-297.310(4), F.A.C.: General Compliance Test Requirements

62-297.310(5), F.A.C.: General Compliance Test Requirements

62-297.310(6), F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)3., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)4., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)5., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)9., F.A.C.: General Compliance Test Requirements

62-297.310(7)(a)10., F.A.C.: General Compliance Test Requirements

62-297.310(8), F.A.C.: General Compliance Test Requirements

62-297.401(1), F.A.C.: EPA Test Method 1

62-297.401(2), F.A.C.: EPA Test Method 2

62-297.401(3), F.A.C.: EPA Test Method 3

62-297.401(4), F.A.C.: EPA Test Method 4

62-297.401(5), F.A.C.: EPA Test Method 5

62-297.401(6), F.A.C.: EPA Test Method 6

62-297.401(6)(c), F.A.C.: EPA Test Method 6C

62-297.401(7), F.A.C.: EPA Test Method 7

62-297.401(7)(e), F.A.C.: EPA Test Method 7E

62-297.401(8), F.A.C.: EPA Test Method 8

62-297.401(9), F.A.C.: EPA Test Method 9

62-297.401(10), F.A.C.: EPA Test Method 10

62-297.401(18), F.A.C.: EPA Test Method 18

62-297.401(25)(a), F.A.C.: EPA Test Method 25A

40 CFR 63.1 – 63.16 – Subpart A – General Provisions: Boiler No. 4 is subject to the notification requirements of Subpart DDDDD.

40 CFR 63.7485 – Subpart DDDDD – Applicability: Boiler No. 4 is an industrial boiler of size > 10 MMBtu/hr located at a major source of HAPs.

40 CFR 63.7490 – Subpart DDDDD – Applicability: Boiler No. 4 is subject to the requirements of Subpart DDDDD for existing boilers.

40 CFR 63.7495 – Subpart DDDDD – Compliance Dates – Boiler No. 4 must meet notification requirements and comply by September 13, 2007.

40 CFR 63.7499 – Subpart DDDDD – Subcategories: Boiler No. 4 is in the large solid fuel subcategory.

40 CFR 63.7506 – Subpart DDDDD – Limited Requirements: Boiler No. 4 must only meet the notification requirements of 63.9(b) at this time.

40 CFR 63.7545 – Subpart DDDDD – Notifications: Boiler No. 4 must submit the required notification by March 12, 2005.

DRAFT PERMIT

PERMITTEE

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440
Authorized Representative:
Mr. Neil Smith, V.P. of Sugar Processing Operations

Air Permit No. 0510003-039-AC
Clewiston Sugar Mill and Refinery
Boilers 1, 2, and 4
Combined Distillate Oil Firing
Permit Expires: January 30, 2007

PROJECT AND LOCATION

This permit combines the oil firing requirements in original Permit No. 0510003-029-AC for Boiler 4 and original Permit No. 0510003-036-AC for Boilers 1 and 2. It established a common maximum fuel sulfur specification of 0.05% sulfur by weight and an oil firing cap of 6,000,000 gallons during any consecutive 12 months from Boilers 1, 2, and 4 (combined). The boilers operate at the existing Clewiston Sugar Mill and Refinery (SIC Nos. 2061 and 2062) located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

STATEMENT OF BASIS

This air pollution construction 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 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. This permit supersedes the oil firing requirements in all previously issued air construction permits for the affected emissions units.

PERMIT CONTENT

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

DRAFT

Joe Kahn, P.E., Acting Director
Division of Air Resource Management

(Effective Date)

FACILITY DESCRIPTION

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

The primary air pollution sources are the five existing boilers, which fire primarily bagasse. Distillate oil is fired as a startup and supplemental fuel. Particulate matter emissions are controlled by wet scrubbers (Boilers 1, 2 and 4) and by electrostatic precipitators (Boilers 7 and 8). Other air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, conditioning silos with dust collectors, vacuum systems, sugar/starch bins, conveyors, and a packaging system. This project only affects the oil firing capabilities of Boilers 1, 2 and 4 (Emissions Units 001, 002 and 009, respectively).

FACILITY REGULATORY CLASSIFICATIONS

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 pursuant to Rule 62-212.400(PSD), F.A.C.

RELEVANT DOCUMENTS

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

APPENDICES

The following Appendices are included as part of the permit in Section 4.

Appendix CF. Citation Format

Appendix GC. General Conditions

Appendix SC. Standard Conditions

1. Permitting Authority: The permitting authority for this project is the Florida Department of Environmental Protection's Bureau of Air Regulation. The mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.
3. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions units 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, the Florida Administrative Code, the Code of Federal Regulations, and any previously issued valid air permits. 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.]
4. 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.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
6. 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.]
7. Title V Permit: A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

A. Boilers 1, 2 and 4

This section of the permit addresses the following emissions units.

EU No.	Emission Unit Description
001	Boiler 1 is a traveling grate boiler with a maximum 1-hour steam production rate of 255,000 pounds per hour at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 125, Joy Turbulaire wet impingement scrubber. Exhaust gases exit at 150° F with an approximate flow rate of 201,000 acfm from a stack that is 8 feet in diameter and 213 feet tall.
002	Boiler 2 is a traveling grate boiler with a maximum 1-hour steam production rate of 230,000 pounds per hour at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 125, Joy Turbulaire wet impingement scrubber. Exhaust gases exit at 150° F with an approximate flow rate of 201,000 acfm from a stack that is 8 feet in diameter and 213 feet tall.
009	Boiler 4 is a traveling grate boiler manufactured by Foster Wheeler with a maximum steam production rate of 300,000 pounds per hour at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 200 Joy Turbulaire wet impingement scrubber. Exhaust gases exit a 150 feet tall stack at 160° F with an approximate flow rate of 281,000 acfm.

EQUIPMENT

1. Oil Firing Modifications:

   a. *Boilers 1 and 2*: For each boiler, the permittee is authorized to replace the existing oil burners with new Peabody-type multi-stage combustion (MSC) burners (or equivalent) to fire distillate oil. In general, each burner consists of a steam-atomized center-fired oil gun, a flame scanner, an ignitor with flame proving rod, and an individual burner windbox with an electrically-operated modulating damper. The project also includes new combustion air fans with associated ductwork, new fuel oil pump sets, and new burner management systems. The burners shall be low-NOx burners designed for a maximum NOx emission rate of 0.17 lb/MMBtu. Each boiler will have one oil burner with a maximum heat input rate of 130 MMBtu/hour. The modified boilers are estimated to produce approximately 97,400 pounds of steam per hour from the sole firing of distillate oil.

   b. *Boiler 4*: The permittee is authorized to replace the existing oil firing system with the following general equipment: two multi-stage combustion low-NOx burners with flame scanner, fuel/steam valve train, steam-atomized center-fired oil gun with ignitor and flame proving rod; a multi-burner windbox; a fuel oil pump set; and a burner management control system. The burners shall be low-NOx burners designed for a maximum NOx emission rate of 0.17 lb/MMBtu. The maximum heat input rate is 326 MMBtu per hour. The modified boiler is estimated to produce approximately 225,000 pounds of steam per hour from the sole firing of distillate oil.

   Bagasse remains the primary fuel. Distillate oil will be fired during startup, to supplement bagasse, and as an alternate fuel to support the refinery when bagasse is not available. This permit only addresses the oil firing aspects of these boilers. [Application; Design]

PERFORMANCE RESTRICTIONS

2. Oil Specification: Any oil fired in Boilers 1, 2 and 4 shall be new No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. [Application; Design; Rule 62-212.400(12), F.A.C.]

3. Permitted Capacity on Oil:

   a. *Boilers 1 and 2*: For each boiler, the maximum heat input rate from distillate oil is 130 MMBtu per hour (963 gallons per hour).

   b. *Boiler 4*: The maximum heat input rate from distillate oil firing is 326 MMBtu per hour (2417 gallons per hour).

   [Application; Design; Rules 62-210.200(PTE) and 62-212.400(12)(Source Obligation), F.A.C.]

4. Oil Firing Cap: Total distillate oil firing shall not exceed 6,000,000 gallons during any consecutive 12 months from Boilers 1, 2 and 4 (combined). The permittee shall install, calibrate, operate, and maintain individual fuel oil flow meters with integrators. [Application; Design; Rules 62-210.200(PTE) and 62-212.400(12)(Source Obligation), F.A.C.

EMISSIONS STANDARDS AND PERFORMANCE TESTING

{Permitting Note: Emissions shall continue to be regulated by the existing permit requirements, which include previous air construction permits and Rule 62-296.410, F.A.C. for carbonaceous fuel burning equipment.}

RECORDS AND REPORTS

5. Oil Firing Records:
   a. *Methods*: The sulfur content of the fuel oil shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department.
   b. *Vendor Analysis*: For each fuel oil delivery, the permittee shall record and retain the following information: the date; gallons delivered; and a fuel oil analysis including the heat content in MMBtu/gallon, the density in pounds/gallon, the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable.
   c. *Actual Sampling*: At least once during each federal fiscal year, the permittee shall have a representative sample analyzed in accordance with the specified methods. Results of the analysis shall be submitted to the Compliance Authority within 45 days of sampling.
   d. *Fuel Consumption*: At the end of each month, the permittee shall read and record the amount indicated by the integrator on the fuel oil flow meter. The permittee shall calculate and record the amount of fuel oil fired during each month and during each consecutive 12-month period. Records shall be available for inspection within ten days following each month.

   [Rule 62-4.070(3), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

6. Previous Permits: This permit supersedes Permit No. 0510003-029-AC for Boiler 4 and Permit No. 0510003-036-AC for Boilers 1 and 2. With regard to the specified oil firing requirements, this permit supplements all other previously issued air construction permits. Except for the specific conditions related to oil firing in this permit, the boilers remain subject to the conditions of all other valid air construction and operations permits. [Rule 62-4.070, F.A.C.]

Filename: 0510003-039-AC - Draft Permit

CONTENTS

Appendix CF. Citation Format
Appendix GC. General Conditions
Appendix SC. Standard Conditions

CITATION FORMAT

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 CRF 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 (not applicable to project);
    b. Determination of Prevention of Significant Deterioration (not applicable to project); and
    c. Compliance with New Source Performance Standards (not applicable to project).

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.

STANDARD CONDITIONS

Unless otherwise specified by permit, the following conditions apply to all emissions units and activities.

EMISSIONS AND CONTROLS

1. 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.]
2. 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.]
3. 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.]
4. 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.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee 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.]
6. 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.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]
8. 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.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

10. 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. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

ATTACHMENT USS-EU3-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 4

ATTACHMENT USS-EU3-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 4 is permitted to operate while combusting carbonaceous fuel alone at a heat input rate of 633 MMBtu/hr (maximum 1-hour average) and 600 MMBtu/hr (maximum 24-hour average); No. 2 fuel oil alone at a maximum fuel oil heat input rate of 326 MMBtu/hr; or a combination of carbonaceous fuel and No. 2 fuel oil at a combined maximum heat input of 633 MMBtu/hr (maximum 1-hour average). Carbonaceous fuel may include incidental amounts of on-specification used oil.

The unit is limited to a maximum of 6,000,000 gallons of No. 2 residual fuel oil for a 12-month period and 2,417 gallons per hour. The sulfur content of No. 2 fuel oil is limited to 0.05 percent by weight. No. 2 fuel oil may include facility-generated, on-specification used oil. The hours of operation for this unit are not restricted (8,760 hours per year).

EMISSION UNIT 5

BOILER #8

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

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

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**NOV 2003**	**MAR 2005**	**20**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

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

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator** **Wet Sand Separator** **Selective Non-Catalytic Reduction System (SNCR)** **Mechanical Dust Collector**	
2. Control Device or Method Code(s): **010, 099, 107, 076**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **550,000 lb/hr steam**	
3. Maximum Heat Input Rate: **1,030** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on 1-hour maximum steam rate (above) for carbonaceous fuel firing. Maximum 24-hour average firing for carbonaceous fuel is 936 MMBtu/hr, corresponding to 500,000 lb/hr steam. Maximum for No. 2 fuel oil is 562 MMBtu/hr. The permitted annual steam production limit is 3.6135 x 10^9 lb of steam per consecutive 12-month period, equivalent to 6,767,100 MMBtu per year.**	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-8**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **13.0** feet
8. Exit Temperature: **335** °F	9. Actual Volumetric Flow Rate: **425,400** acfm	10. Water Vapor: **24** %

11. Maximum Dry Standard Flow Rate: **225,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on biomass firing at maximum 24-hour heat input rate. Maximum Dry Standard Flow Rate is at 7-percent oxygen.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

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

Segment Description and Rate: Segment 2 of 3

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

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type):

   External combustion boiler; industrial; wood/bark (>50,000 lb/hr steam)

2. Source Classification Code (SCC): **1-02-009-02**	3. SCC Units: **Tons Burned**

4. Maximum Hourly Rate: **126.54**	5. Maximum Annual Rate: **831,339**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05 (dry)**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **8.14**

10. Segment Comment:
Maximum hourly rate based on 1,030 MMBtu/hr (1-hr max) and 4,070 Btu/lb (wet) for wood/bark. Maximum annual rate based on 6,767,100 MMBtu/yr.

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):

2. Source Classification Code (SCC):	3. SCC Units:

4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

10. Segment Comment:

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	099	010	EL
PM_{10}	099	010	EL
SO_2			EL
NO_x	107		EL
CO			EL
VOC			EL
SAM			NS
PB	099	010	NS
H017 (Benzene)			NS
H095 (Formaldehyde)			NS
H106 (Hydrogen Chloride)	010		EL
H114 (Mercury)			EL
HAPs			NS
Ammonia			EL

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **25.75** lb/hour **84.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **MACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.025 lb/MMBtu = 25.75 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.025 lb/MMBtu ÷ 2,000 lb/ton = 84.6 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B and 40 CFR 63, Subpart DDDDD, Table 1.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **23.4** lb/hour tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 63, Subpart DDDDD, Table 1. Hourly emissions based on maximum 24-hour average heat input.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **84.6** tons/year
5. Method of Compliance: **EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 63, Subpart DDDDD, Table 1. Annual emissions based on 6,767,100 MMBtu/yr heat input.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **25.75** lb/hour tons/year
5. Method of Compliance: **EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 63, Subpart DDDDD, Table 1. Hourly emissions based on maximum 1-hour heat input.**	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **25.75** lb/hour **84.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **MACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.025 lb/MMBtu = 25.75 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.025 lb/MMBtu ÷ 2,000 lb/ton = 84.6 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **23.4** lb/hour tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 63, Subpart DDDDD, Table 1. Hourly emissions based on maximum 24-hour average heat input.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **84.6** tons/year
5. Method of Compliance: **EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 61, Subpart DDDDD, Table 1. Annual emissions based on 6,767,100 MMBtu/yr heat input.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **25.75** lb/hour tons/year
5. Method of Compliance: **EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 61, Subpart DDDDD, Table 1. Hourly emissions based on maximum 1-hour heat input.**	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **61.8** lb/hour **203.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu (1-hour)** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.06 lb/MMBtu = 61.8 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.06 lb/MMBtu ÷ 2,000 lb/ton = 203.0 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Potential emissions representative of bagasse firing. Hourly and Annual based on Permit No. 0510003-030-AC/PSD-FL-333B.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **56.2** lb/hour tons/year
5. Method of Compliance: **EPA Method 6C**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-030-AC/PSD-FL-333B. Emissions representative of 24-hour heat input.**	

Allowable Emissions Allowable Emissions 2 of 4

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

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **61.8** lb/hour tons/year
5. Method of Compliance: **EPA Method 6C**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-030-AC/PSD-FL-333B. Emissions representative of maximum 1-hour heat input.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **203.0** tons/year
5. Method of Compliance: **EPA Method 6C**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0510003-030-AC/PSD-FL-333B. Emissions based on annual heat input limit.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **309.0** lb/hour **744.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.14 lb/MMBtu, 30-day rolling average** Reference: **Permit No. 0510003-030-AC/PSD-FL-333B**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Maximum hourly rate: 1,030 MMBtu/hr x 0.030 lb/MMBtu = 309.0 lb/hr
Annual: 6,767,100 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 473.7 TPY

11. Potential Fugitive and Actual Emissions Comment:
Maximum hourly rate represents worst-case uncontrolled without SNCR system. Annual average is 30-day rolling average limit, based on permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6,695** lb/hour **1,285** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **400 ppmvd @ 7% O_2, 30-day rolling.** Reference: **40 CFR 63, Subpart DDDDD**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum hourly rate: 1,030 MMBtu/hr x 6.5 lb/MMBtu = 6,383 lb/hr
30-day rolling average based on 40 CFR 63, Subpart DDDDD:
400 ppmvd @ 7-percent O_2 x 225,000 dscfm @ 7-percent O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1,545.6/28) ft-lb_f/lb_m-°R ÷ 528°R = 392.2 lb/hr
Annual based on 30-day rolling average: 392.2 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,717.8 TPY
Annual limit based on PSD-FL-333B: 0.38 lb/MMBtu (12-month rolling average)
6,767,100 MMBtu/yr x 0.38 lb/MMBtu ÷ 2,000 lb/ton = 1,285 TPY

11. Potential Fugitive and Actual Emissions Comment:

Annual limit based on 12-month rolling average, based on Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1,285 TPY**	4. Equivalent Allowable Emissions: lb/hour **1,285** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit from PSD-FL-333B based on 12-month rolling average. The limit includes periods of startup, shutdown, and malfunction (SSM).**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **400 ppmvd @ 7-percent O_2**	4. Equivalent Allowable Emissions: **392.2** lb/hour **1,717.8** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 63, Subpart DDDDD, Table 1. Limit based on 30-day rolling average. Excludes periods of SSM.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **51.5** lb/hour **169.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.05 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Maximum hourly rate: 1,030 MMBtu/hr x 0.05 lb/MMBtu = 51.5 lb/hr
Annual: 6,767,100 MMBtu/yr x 0.05 lb/MMBtu ÷ 2,000 lb/ton = 169.2 TPY

11. Potential Fugitive and Actual Emissions Comment:
Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **51.5** lb/hour tons/year
5. Method of Compliance: **EPA Methods 18 and 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit. Emissions based on maximum 1-hour heat input rate.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **46.8** lb/hour tons/year
5. Method of Compliance: **EPA Methods 18 and 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit based on maximum 24-hour heat input.**	

Allowable Emissions Allowable Emissions 3 of 3

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

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

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

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

1. Pollutant Emitted: **H114 (Mercury)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00309** lb/hour **0.0102** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3 x 10^{-6} lb/MMBtu** Reference: **40 CFR 63, Subpart DDDDD, Table 1.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **3 x 10^{-6} lb/MMBtu x 1,030 MMBtu/hr = 0.00309 lb/hr** **3 x 10^{-6} lb/MMBtu x 6,767,100 MMBtu/yr ÷ 2,000 lb/ton = 0.0102 TPY**	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 x 10^{-6} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.00309** lb/hour **0.0102** tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **HCl**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **20.6** lb/hour **67.67** tons/year

4. Synthetically Limited? ☒ Yes ☐ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.02 lb/MMBtu**
Reference: **40 CFR 63, Subpart DDDDD, Table 1.**

7. Emissions Method Code: **0**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
0.02 lb/MMBtu x 1,030 MMBtu/hr = 20.6 lb/hr
0.02 lb/MMBtu x 6,767,100 MMBtu/yr ÷ 2,000 lb/ton = 67.67

11. Potential Fugitive and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.02 lb/MMBtu**	4. Equivalent Allowable Emissions: **20.6** lb/hour **67.67** tons/year
5. Method of Compliance: **Annual stack testing using EPA Method 26A**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NH_3**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.9** lb/hour **52.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **20 ppmvd @ 7-percent O_2** Reference: **PSD-FL-333B**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
20 ppmvd @ 7-percent O_2 x 225,000 dscfm @ 7-percent O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1545.6/17) ft-lb_f/lb_m-°R ÷ 528°R = 11.9 lb/hr
11.9 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 52.1 TPY

11. Potential Fugitive and Actual Emissions Comment:
Emission factor based on Permit No. PSD-FL-333B. Reflects maximum 24-hour average gas flow rate.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd @ 7-percent O_2**	4. Equivalent Allowable Emissions: **11.9** lb/hour **52.1** tons/year
5. Method of Compliance: **Annual stack test by method EPA CTM-027.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on Permit No. PSD-FL-333B. Hourly emissions based on maximum 24-hour average gas flow rate.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Siemens** Model Number: **6E**	Serial Number:
5. Installation Date: **January 2005**	6. Performance Specification Test Date: **January 10-11, 2006**
7. Continuous Monitor Comment: **Based on 40 CFR 63, Subpart DDDDD and Permit No. 0510003-030-AC/PSD-FL-333B.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Rosemount** Model Number: **951C**	Serial Number:
5. Installation Date: **January 2005**	6. Performance Specification Test Date: **January 10-11, 2006**
7. Continuous Monitor Comment: **Based on BACT and Permit No. 0510003-030-AC/PSD-FL-333B.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **Siemens** Model Number: Serial Number:	
5. Installation Date: **January 2005**	6. Performance Specification Test Date: **January 10-11, 2006**
7. Continuous Monitor Comment: **Based on 40 CFR 63, Subpart DDDDD and Permit No. 0510003-030-AC/PSD-FL-333B.**	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU5-I1** ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU5-I2** ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU5-I3** ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU5-I4** ☐ Previously Submitted, Date ____ ☐ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Previously Submitted, Date: **Jan. 2006; June 2006** Test Date(s)/Pollutant(s) Tested: **PM, HCl, VOC, SO_2, NH_3** ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

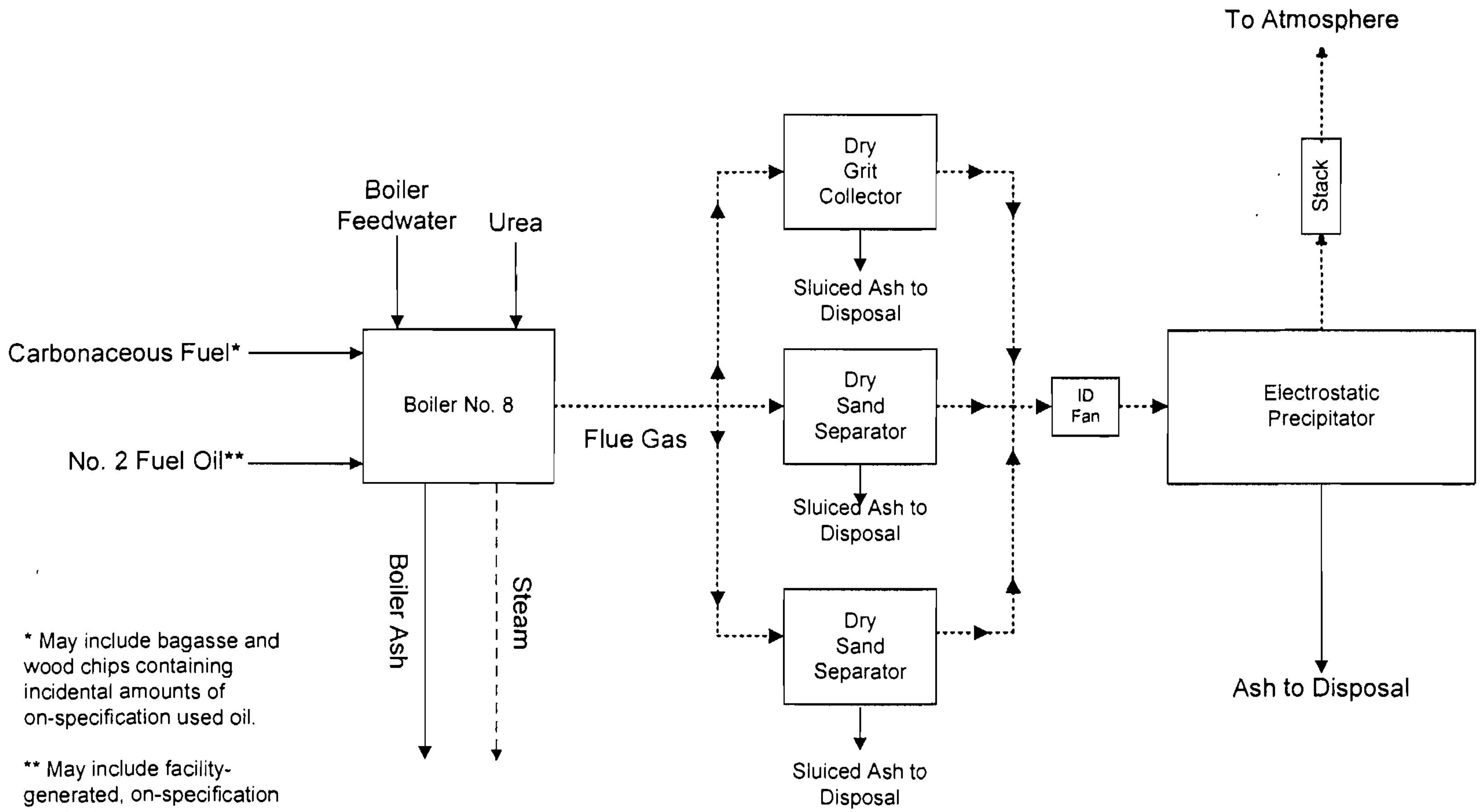
1. Identification of Applicable Requirements ☒ Attached, Document ID: USS-EU5-IV1 ☐ Not Applicable	
2. Compliance Assurance Monitoring ☒ Attached, Document ID: USS-EU5-IV1 ☐ Not Applicable	
3. Alternative Methods of Operation ☒ Attached, Document ID: USS-EU5-IV3 ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT USS-EU5-I1

PROCESS FLOW DIAGRAM

Boiler No. 8



* May include bagasse and wood chips containing incidental amounts of on-specification used oil.

** May include facility-generated, on-specification used oil.

Attachment USS-EU5-I1
Boiler No. 8 Process Flow Diagram
U.S. Sugar Corporation
Clewiston Mill, Florida

Process Flow Legend
Solid/Liquid
Gaseous
Steam

File: 0537540/4.1/RAI082806/USS-EU5-I1.vsd
Date: 8/31/06

Golder Associates

ATTACHMENT USS-EU5-I2

FUEL ANALYSIS

Boiler No. 8

ATTACHMENT USSC-EU5-I2

BOILER NO. 8 FUEL ANALYSIS

Parameter	Carbonaceous Fuel [a]		No. 2 Fuel Oil
	Bagasse	Wood Chips	(0.05% S max)
Density (lb/gal)	--	--	6.83
Approximate Heating Value (Btu/l	3,600 [b]	4,070 [b]	19,910
Approximate Heating Value (Btu/;	--	--	135,000
Ultimate Analysis (dry basis):			
Carbon	47.6%	40.70%	84.7%
Hydrogen	6.0%	4.90%	15.3%
Nitrogen	0.38%	0.37%	0.015%
Oxygen	42.1%	33.20%	0.38%
Sulfur	0.03% - 0.07%	0.05%	0.05%
Ash/Inorganic	2.6% - 5.3%	20.80%	0.06% [c]
Moisture	49% - 55%	38.50%	0.51% [c]

Represents typical values.

[a] Source: U.S. Sugar fuel analysis averages.
[b] Wet basis.
[c] Source: Perry's Chemical Engineer's Handbook. Sixth Edition, 1984. Represents average fuel characteristics.

ATTACHMENT USS-EU5-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

Boiler No. 8

ATTACHMENT USS-EU5-I3a

DESIGN CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 8
AT U.S. SUGAR CLEWISTON MILL

DRY SAND SEPARATORS*

Control Device Type	Dry Cyclone
Manufacturer and Model No.	Thermal Energy Systems
Inlet Flue Gas Temp (^oF)	400
Inlet Design Flue Gas Flow Rate (acfm)	230,000
Inlet Expected Flue Gas Flow Rate (acfm)	168,000
Inlet Moisture (% Volume)	24
Cyclone Diameter (ft)	22
Cyclone Height (ft)	35
Pressure Drop (in H_2O)	4
Overall PM Collection Efficiency (%)	80

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

ATTACHMENT USS-EU5-I3b

DESIGN CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 8
U.S. SUGAR CLEWISTON MILL

ELECTROSTATIC PRECIPITATOR

Manufacturer and Model No.	PPC Industries Model No. 41R-1536-5712P		
Inlet Flue Gas Temp (°F)			335
Inlet Design Flue Gas Flow Rate (acfm)			432,500
Moisture (% Volume)			20
No. of Precipitators			1
Precipitation Type			Rigid Electrode
Total Number of Fields			5
Total Installed Collection Area (ft^2)			154,360
Gas Velocity (ft/s)			3.25
Specific Collection Area (ft^2/1,000 acfm)			356
Power Consumption (KW)			250
Pressure Drop (in H_20)			1
Pollutants	Inlet Loading (lb/hr)	Outlet Loading (lb/hr)	Control Efficiency %
Particulate Matter	5,346	25.8	99.5

Design Inlet loading calculation:
Uncontrolled: 5.19 lb/MMBtu x 1,030 MMBtu/hr = 5,346 lb/hr
ESP outlet loading (max) = 25.75 lb/hr (based on 0.025 lb/MMBtu)
ESP efficiency (min) = (5,346 - 25.75) / 5,346 = 99.5%

ATTACHMENT USS-EU5-I3c

DESIGN CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 8 AT U.S. SUGAR CLEWISTON MILL

DRY GRIT COLLECTOR*

Control Device Type	Dry Multiclone
Manufacturer and Model No.	Howden Energy Systems
Inlet Flue Gas Temp (°F)	385
Inlet Design Flue Gas Flow Rate (acfm)	90,000
Inlet Moisture (% Volume)	24
No. of Cyclones	40
Cyclone Diameter (ft)	1.26
Cyclone Height (ft)	2.70
Pressure Drop (in H_2O)	3
Overall PM Collection Efficiency (%)	83

*There is one dry sand separator (multiclone).

ATTACHMENT USS-EU5-13d

CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 8

U.S. SUGAR CLEWISTON MILL

SELECTIVE NON-CATALYTIC REDUCTION SYSTEM

Manufacturer and Model No.	FuelTech		
Flue Gas Temp At Injections (^{o}F)			1,800-2,000
Flue Gas Flow Rate (acfm)			425,000
Moisture (% Volume)			24
No. of Injection Levels			3
Total No. of Injections			28
NO_x - OUT (urea) usage (max gal/hr)			76
Maximum Ammonia Slip (ppm)			20
Pollutants	Inlet Loading (lb/MMBtu)	Outlet Loading (lb/MMBtu)	Control Efficiency %
Nitrogen Oxides	0.28 - 0.32	0.14	44 - 50

ATTACHMENT USS-EU5-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

Boiler No. 8

ATTACHMENT UC-EU5-I4

CLEWISTON BOILER NO. 8

PROCEDURES FOR STARTUP AND SHUTDOWN

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

Cold Startup (approximately 6 to 12 hours)

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

Hot Startup (approximately 1 to 5 hours)

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

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

Shutdown

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

ATTACHMENT USS-EU5-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Boiler No. 8

ATTACHMENT USS-EU5-IV1a

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Boiler No. 8

40 CFR 60.40b(a): 40 CFR 63, Subpart Db Applicability

40 CFR 60.40b(j): 40 CFR 63, Subpart Db Applicability

40 CFR 60.42b(a): Standard for Sulfur Dioxide

40 CFR 60.42b(j)(2): Standard for Sulfur Dioxide

40 CFR 60.43b(e): Standard for Particulate Matter and Opacity

40 CFR 60.43b(f): Standard for Particulate Matter and Opacity

40 CFR 60.43b(g): Standard for Particulate Matter and Opacity

40 CFR 60.45b(a): Compliance and Performance Test Methods for Sulfur Dioxide

40 CFR 60.45b(j): Compliance and Performance Test Methods for Sulfur Dioxide

40 CFR 60.46b(a): Compliance and Performance Test Methods for PM

40 CFR 60.46b(d)7: Compliance and Performance Test Methods for PM

40 CFR 60.47b(f): Emission Monitoring for Sulfur Dioxide

40 CFR 60.48b(a): Emission Monitoring for Particulate Matter and Nitrogen Oxides

40 CFR 60.49b(a): Reporting and Recordkeeping Requirements

40 CFR 60.49b(d): Reporting and Recordkeeping Requirements

40 CFR 60.49b(f): Reporting and Recordkeeping Requirements

40 CFR 60.49b(h)(1): Reporting and Recordkeeping Requirements

40 CFR 60.49b(h)(3): Reporting and Recordkeeping Requirements

40 CFR 60.49b(j): Reporting and Recordkeeping Requirements

40 CFR 60.49b(o): Reporting and Recordkeeping Requirements

40 CFR 60.49b(r): Reporting and Recordkeeping Requirements

62-204.800(b)(3), F.A.C.: NSPS Subpart Db – Adopted by Reference

62-212.400, F.A.C.: Prevention of Significant Deterioration

62-296.410(2), F.A.C.: Carbonaceous Fuel Burning Equipment

62-296.410(3), F.A.C.: Carbonaceous Fuel Burning Equipment

62.297.310(1), F.A.C.: General Compliance Test Requirements

62-297-310(2)(b), F.A.C.: General Compliance Test Requirements

62-297-310(3), F.A.C.: General Compliance Test Requirements

62-297-310(4), F.A.C.: General Compliance Test Requirements

62-297-310(5), F.A.C.: General Compliance Test Requirements

62-297-310(6), F.A.C.: General Compliance Test Requirements

62-297-310(7), F.A.C.: General Compliance Test Requirements

62-297-310(8), F.A.C.: General Compliance Test Requirements

62-297.401(1), F.A.C.: EPA Test Method 1

62-297.401(2), F.A.C.: EPA Test Method 2

62-297.401(3), F.A.C.: EPA Test Method 3

62-297.401(4), F.A.C.: EPA Test Method 4

62-297.401(5), F.A.C.: EPA Test Method 5

62-297.401(6), F.A.C.: EPA Test Method 6

62-297.401(6c), F.A.C.: EPA Test Method 6C

62-297.401(7), F.A.C.: EPA Test Method 7

62-297.401(7e), F.A.C.: EPA Test Method 7E

62-297.401(8), F.A.C.: EPA Test Method 6C

62-297.401(9), F.A.C.: EPA Test Method 9

62-297.401(10), F.A.C.: EPA Test Method 10

62-297.401(18), F.A.C.: EPA Test Method 18

62-297.401(25a), F.A.C.: EPA Test Method 25A

40 CFR 63 – Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters
(See Attachment USS-EU5-IV1b)

ATTACHMENT USS-EU5-IV1b
NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	**Sec. 63.7480 What is the purpose of this subpart?**	
Y	This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.	
Y	**Sec. 63.7485 Am I subject to this subpart?**	
Y	You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 63.2 or Sec. 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in Sec. 63.7491.	Clewiston is a major source of HAPs, and Boiler No. 8 has a heat input capacity of greater than 10 MMBtu/hr.
Y	**Sec. 63.7490 What is the affected source of this subpart?**	
Y	(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.	
N	(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in Sec. 63.7575.	
Y	(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in Sec. 63.7575.	Construction of Boiler No. 8 began after Jan. 13, 2003.
Y	(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.	Construction of Boiler No. 8 began after Jan. 13, 2003.
N	(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in Sec. 63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.	
N	(d) A boiler or process heater is existing if it is not new or reconstructed.	
N	**Sec. 63.7491 Are any boilers or process heaters not subject to this subpart?**	
N	The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.	
N	(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBB, subpart Cb or subpart Eb.	
N	(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.	
N	(c) An electric utility steam generating unit that is a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity, and supplies more than one-third of its potential electric output capacity, and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.	
N	(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE (e.g., hazardous waste boilers).	
N	(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCC or subpart DDDD.	
N	(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.	
N	(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.	
N	(h) A hot water heater as defined in this subpart.	
N	(i) A refining kettle covered by 40 CFR part 63, subpart X.	
N	(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(k) Blast furnace stoves as described in the EPA document, entitled ``National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants--Background Information for Proposed Standards," (EPA-453/R-01-005).	
N	(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.	
N	(m) Any boiler and process heater specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).	
N	(n) Temporary boilers as defined in this subpart.	
N	(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.	
Y	**Sec. 63.7495 When do I have to comply with this subpart?**	
Y	(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.	Boiler No. 8 wil comply upon startup.
N	(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.	
N	(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.	
N	(1) Any new or reconstructed boiler or process heater at the existing facility must be in compliance with this subpart upon startup.	
N	(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.	
Y	(d) You must meet the notification requirements in Sec. 63.7545 according to the schedule in Sec. 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.	
Y	**Emission Limits and Work Practice Standards**	
Y	**Sec. 63.7499 What are the subcategories of boilers and process heaters?**	
Y	The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in Sec. 63.7575.	Boiler No. 8 is in the large solid fuel category.
Y	**Sec. 63.7500 What emission limits, work practice standards, and operating limits must I meet?**	
Y	(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.	
Y	(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under Sec. 63.7507.	Boiler No. 8 must meet MACT standards for new sources.
Y	Table 1: PM - 0.025 lb/MMBtu, or TSM - 0.0003 lb/MMBtu*	New source standard.
Y	HCl - 0.02 lb/MMBtu*	New source standard.
Y	Hg - 3E-06 lb/MMBtu	New source standard.
Y	CO - 400 ppmvd @ 7% O2, 30-day rolling average	New source standard.
Y	* May opt to demonstrate compliance with health-based alternative for HCl and TSM.	New source standard.
Y	(2) You must meet each operating limit in Tables 2 through 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under Sec. 63.8(f).	Boiler No. 8 uses the combination of wet scrubber and ESP control devices.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	Tables 2, 3 and 4: PM, TSM, Hg - if using ESP control with additional wet control system: maintain minimum voltage and secondary current or total power input to the ESP at or above compliance test values.	Boiler No. 8 will use ESP control with additional wet control system: maintain minimum voltage and secondary current or total power input to the ESP at or above compliance test values.
Y	HCl - maintain minimum scrubber effluent pH, pressure drop and liquid flow rate at or above compliance test values.	Boiler No. 8 will maintain minimum scrubber effluent pH, pressure drop and liquid flow rate at or above compliance test values.
Y	Fuel Analysis - maintain fuel type such that Hg, TSM and HCl emission rates are less than applicable limits.	Boiler No. 8 will use Fuel Analysis and maintain fuel type such that Hg emission rate is less than applicable limit.
Y	(b) As provided in Sec. 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.	Boiler No. 8 is requesting some altenatives to test procedures.
Y	**General Compliance Requirements**	
Y	**Sec. 63.7505 What are my general requirements for complying with this subpart?**	
Y	(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.	
Y	(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in Sec. 63.6(e)(1)(i).	
Y	(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to Sec. 63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.	Boiler No. 8 will demonstrate compliance with Hg limits through fuel analysis.
Y	(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under Sec. 63.8(f).	Boiler No. 8 will demonstrate compliance with TSM and HCl limits through fuel analysis.
Y	(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan at least 60 days before your initial performance evaluation of your CMS.	A site-specific monitoring is being submitted.
Y	(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);	A site-specific monitoring is being submitted.
Y	(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and	A site-specific monitoring is being submitted.
Y	(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).	A site-specific monitoring is being submitted.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.	A site-specific monitoring is being submitted.
Y	(i) Ongoing operation and maintenance procedures in accordance with the general requirements of Sec. 63.8(c)(1), (c)(3), and (c)(4)(ii);	A site-specific monitoring is being submitted.
Y	(ii) Ongoing data quality assurance procedures in accordance with the general requirements of Sec. 63.8(d); and	A site-specific monitoring is being submitted.
Y	(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of Sec. 63.10(c), (e)(1), and (e)(2)(i).	A site-specific monitoring is being submitted.
Y	(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.	A site-specific monitoring is being submitted.
Y	(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.	A site-specific monitoring is being submitted.
Y	(e) If you have an applicable emission limit or work practice standard, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in Sec. 63.6(e)(3).	A SSM Plan will be developed prior to startup of Boiler No. 8.
Y	**Sec. 63.7506 Do any boilers or process heaters have limited requirements?**	
N	(a) New or reconstructed boilers and process heaters in the large liquid fuel subcategory or the limited use liquid fuel subcategory that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and maintain operating limits to demonstrate continuous compliance with the emission limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section and meet the CO work practice standard in Table 1 to this subpart.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in Sec. 63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in Sec. 63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in Sec. 63.9(b) (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(1) Existing large and limited use gaseous fuel units.	Boiler No. 8 is not in the gaseous fuel subcategory.
N	(2) Existing large and limited use liquid fuel units.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(3) New or reconstructed small liquid fuel units that burn only gaseous fuels or distillate oil. New or reconstructed small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in Sec. 63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(1) Existing small solid fuel boilers and process heaters.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(2) Existing small liquid fuel boilers and process heaters.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(3) Existing small gaseous fuel boilers and process heaters.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(4) New or reconstructed small gaseous fuel units.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	**Sec. 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?**	
N	(a) As an alternative to the requirement for large solid fuel boilers located at a single facility to demonstrate compliance with the HCl emission limit in Table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.	
N	(b) In lieu of complying with the TSM emission standards in Table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM emission standards in Table 1 based on the sum of emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions) under the procedures prescribed in appendix A to this subpart.	
Y	**Testing, Fuel Analyses, and Initial Compliance Requirements**	
Y	**Sec. 63.7510 What are my initial compliance requirements and by what date must I conduct them?**	
Y	(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to Sec. 63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to Sec. 63.7521 and Table 6 to this subpart, establishing operating limits according to Sec. 63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to Sec. 63.7525.	Boiler No. 8 will demonstrate compliance through a combination of methods.
Y	(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to Sec. 63.7521 and Table 6 to this subpart and establish operating limits according to Sec. 63.7530 and Table 8 to this subpart.	Boiler No. 8 will demonstrate compliance with the Hg limit through fuel analysis, ...

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to Sec. 63.7525(a).	Boiler No. 8 will be subject to the CO work practice standard.
N	(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in Sec. 63.7495 and according to the applicable provisions in Sec. 63.7(a)(2) as cited in Table 10 to this subpart.	Boiler No. 8 is not an existing affected source.
Y	(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and November 12, 2004, you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after November 12, 2004 or within 180 days after startup of the source, whichever is later, according to Sec. 63.7(a)(2)(ix).	Boiler No. 8 will demonstrate compliance with the promulgated emisison limits and work practice standards within 180 days of startup.
N	(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and November 12, 2004, and you chose to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after November 12, 2004 or within 3 years after startup of the affected source, whichever is later.	Boiler No. 8 will demonstrate compliance with the promulgated emisison limits and work practice standards within 180 days of startup.
N	(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.	Boiler No. 8 commenced construction prior to November 12, 2004.
Y	**Sec. 63.7515 When must I conduct subsequent performance tests or fuel analyses?**	
Y	(a) You must conduct all applicable performance tests according to Sec. 63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.	
Y	(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.	
Y	(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.	
Y	(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.	
N	(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.	Boiler No. 8 is not in any of the limited use subcategories, and has a heat input capacity less than 100 MMBtu/hr.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(f) You must conduct a fuel analysis according to Sec. 63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in Sec. 63.7540.	
Y	(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to Sec. 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in Sec. 63.7550.	
Y	**Sec. 63.7520 What performance tests and procedures must I use?**	
Y	(a) You must conduct all performance tests according to Sec. 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in Sec. 63.7(c) if you elect to demonstrate compliance through performance testing.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.	
N	(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to Sec. 63.7506(a).	Boiler No. 8 is not in one of the liquid fuel subcategories.
Y	(d) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.	
Y	(f) You must conduct three separate test runs for each performance test required in this section, as specified in Sec. 63.7(e)(3). Each test run must last at least 1 hour.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	(g) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	**Sec. 63.7521 What fuel analyses and procedures must I use?**	
Y	(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.	Boiler No. 8 will be required to conduct fuel analysis for TSM, Hg and HCl.
Y	(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.	
Y	(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.	
Y	(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.	
Y	(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.	
Y	(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
N	(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.	Boiler No. 8 will not rely upon a fuel analysis from a fuel supplier.
Y	(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.	
Y	(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.	Boiler No. 8 will submit a request for an alternative test procedure since it is not practical to stop the belt feeder.
Y	(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.	
Y	(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.	
Y	(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.	
Y	(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.	
Y	(iii) Transfer all samples to a clean plastic bag for further processing.	
Y	(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.	
Y	(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.	
Y	(2) Break sample pieces larger than 3 inches into smaller sizes.	
Y	(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.	
Y	(4) Separate one of the quarter samples as the first subset.	
Y	(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.	
Y	(6) Grind the sample in a mill.	

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Y	(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.	
Y	(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.	
N	**Sec. 63.7522 Can I use emission averaging to comply with this subpart?**	Boiler No. 8 is not eligible for the emissions averaging option.
N	(a) As an alternative to meeting the requirements of Sec. 63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.	
N	(b) For each existing large solid fuel boiler in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on November 12, 2004 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on November 12, 2004.	
N	(c) You may average particulate matter or TSM, HCl, and mercury emissions from existing large solid fuel boilers to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (d), (e), and (f) of this section.	
N	(d) The weighted average emissions from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in Sec. 63.7495.	
N	(e) You must demonstrate initial compliance according to paragraphs (e)(1) or (2) of this section.	
N	(1) You must use Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.	
N	Where:	
N	AveWeighted = Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Hm = Maximum rated heat input capacity of boiler, i, in units of million Btu per hour.	
N	n = Number of large solid fuel boilers participating in the emissions averaging option.	
N	(2) If you are not capable of monitoring heat input, you can use Equation 2 of this section as an alternative to using equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.	
N	Where:	
N	AveWeighted = Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Sm = Maximum steam generation by boiler, i, in units of pounds.	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.	
N	(f) You must demonstrate continuous compliance on a 12-month rolling average basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) and (2). The first 12-month rolling-average period begins on the compliance date specified in Sec. 63.7495.	
N	(1) For each calendar month, you must use Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual heat capacity for each existing large solid fuel boiler participating in the emissions averaging option.	
N	Where:	
N	AveWeighted Emissions = 12-month rolling average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate, calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Hb = The average heat input for each calendar month of boiler, i, in units of million Btu.	
N	n = Number of large solid fuel boilers participating in the emissions averaging option.	
N	(2) If you are not capable of monitoring heat input, you can use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.	
N	Where:	
N	AveWeighted Emissions = 12-month rolling average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate, calculated during the most recent compliance test (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Sa = Actual steam generation for each calender month by boiler, i, in units of pounds.	
N	Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.	
N	(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory authority for review and approval according to the following procedures and requirements in paragraphs (g)(1) through (4).	
N	(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.	
N	(2) You must include the information contained in paragraphs g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:	
N	(i) The identification of all existing large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;	
N	(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;	
N	(iii) The specific control technology or pollution prevention measure to be used for each emission source in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple sources, the owner or operator must identify each source;	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(iv) The test plan for the measurement of particulate matter (or TSM), HCl, or mercury emissions in accordance with the requirements in Sec. 63.7520;	
N	(v) The operating parameters to be monitored for each control system or device and a description of how the operating limits will be determined;	
N	(vi) If you request to monitor an alternative operating parameter pursuant to Sec. 63.7525, you must also include:	
N	(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and	
N	(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and	
N	(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.	
N	(3) Upon receipt, the regulatory authority shall review and approve or disapprove the plan according to the following criteria:	
N	(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and	
N	(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.	
N	(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:	
N	(i) Any averaging between emissions of differing pollutants or between differing sources; or	
N	(ii) The inclusion of any emission source other than an existing large solid fuel boiler.	
Y	**Sec. 63.7525 What are my monitoring, installation, operation, and maintenance requirements?**	
Y	(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in Sec. 63.7495.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR, part 60, appendix B, and according to the site-specific monitoring plan developed according to Sec. 63.7505(d).	Boiler No. 8 will be subject to the CO work practice standard.
Y	(2) You must conduct a performance evaluation of each CEMS according to the requirements in Sec. 63.8 and according to PS 4A of 40 CFR part 60, appendix B.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(4) The CEMS data must be reduced as specified in Sec. 63.8(g)(2).	Boiler No. 8 will be subject to the CO work practice standard.
Y	(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods 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.	Boiler No. 8 will be subject to the CO work practice standard.

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(b) If you have an applicable opacity operating limit, you must install, operate, certify, and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of this section by the compliance date specified in Sec. 63.7495.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(2) You must conduct a performance evaluation of each COMS according to the requirements in Sec. 63.8 and according to PS 1 of 40 CFR part 60, appendix B.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(3) As specified in Sec. 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(4) The COMS data must be reduced as specified in Sec. 63.8(g)(2).	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in Sec. 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of Sec. 63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(7) You must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
Y	(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in Sec. 63.7495.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods 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.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(5) Record the results of each inspection, calibration, and validation check.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(4) Conduct a flow sensor calibration check at least semiannually.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(4) Check pressure tap pluggage daily.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(2) Ensure the sample is properly mixed and representative of the fluid to be measured.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.	Boiler No. 8 will be required to measure ESP operating parameters.
N	(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.	Boiler No. 8 will not utilize sorbent injection.
N	(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.	Boiler No. 8 will not utilize sorbent injection.
N	(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.	Boiler No. 8 will not utilize sorbent injection.
N	(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.	Boiler No. 8 will not utilize sorbent injection.
N	(i) If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of this section.	Boiler No. 8 will not use a fabric filter.
N	(4) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.	Boiler No. 8 will not use a fabric filter.
N	(5) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA 454/R-98-015, September 1997.	Boiler No. 8 will not use a fabric filter.

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N	(6) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.	Boiler No. 8 will not use a fabric filter.
N	(7) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.	Boiler No. 8 will not use a fabric filter.
N	(8) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.	Boiler No. 8 will not use a fabric filter.
N	(9) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.	Boiler No. 8 will not use a fabric filter.
N	(10) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.	Boiler No. 8 will not use a fabric filter.
N	(11) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.	Boiler No. 8 will not use a fabric filter.
Y	**Sec. 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?**	
Y	(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to Sec. 63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to Sec. 63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.	Boiler No. 8 will conduct initial performance tests for PM and HCl and fuel analysis for Hg.
N	(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to Sec. 63.7506(a).	Boiler No. 8 is not in one of the liquid fuel subcategories.
Y	(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in Sec. 63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to Sec. 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.	Boiler No. 8 will conduct initial performance tests for PM, PM and HCl and fuel analysis for Hg.
Y	(1) You must establish the maximum chlorine fuel input (Cinput) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.	Boiler No. 8 will conduct initial performance tests and fuel analysis for HCl.
Y	(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.	
Y	(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).	
Y	(iii) You must establish a maximum chlorine input level using Equation 5 of this section.	
Y	Where:	
Y	Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.	
Y	Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.	

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Y	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
Y	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.	
N	(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level (TSMinput) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.	Boiler No. 8 will not choose to comply with the alternative TSM limit.
N	(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.	
N	(ii) During the performance testing for TSM, you must determine the fraction of total heat input from each fuel burned (Qi) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned (Mi).	
N	(iii) You must establish a baseline TSM input level using Equation 6 of this section.	
N	Where:	
N	TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.	
N	Mi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
N	Qi = Fraction of total heat input from based fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
N	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.	
N	(3) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.	Boiler No. 8 will comply with the Hg limit through fuel analysis.
N	(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.	
N	(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).	
N	(iii) You must establish a maximum mercury input level using Equation 7 of this section.	
N	Where:	
N	Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.	
N	HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
N	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.	
Y	(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.	
Y	(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in Sec. 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.	Boiler No. 8 will utilize a wet scrubber.
Y	(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in Sec. 63.7575, as your operating limits during the three-run performance test.	Boiler No. 8 will utilize an ESP.
N	(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in Sec. 63.7575, as your operating limit during the three-run performance test.	Boiler No. 8 will not utilize a dry scrubber.
N	(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in Sec. 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.	Boiler No. 8 will not utilize a fabric filter.
Y	(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to Sec. 63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.	Boiler No. 8 will comply with the Hg limit through fuel analysis.
Y	(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.	The worst case fuel will be bagasse.
Y	(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.	
Y	Where:	
Y	P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.	
Y	mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
Y	SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
Y	t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.	
Y	(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.	Boiler No. 8 will comply with the HCl limit through fuel analysis and a site-specific risk analysis.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	Where:	
Y	HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.	
Y	Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.	
Y	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
Y	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.	
Y	1.028 = Molecular weight ratio of HCl to chlorine.	
N	(4) To demonstrate compliance with the applicable emission limit for TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.	Boiler No. 8 will not choose to comply with the alternative TSM limit.
N	Where:	
N	TSM = TSM emission rate from the boiler or process heater in units of pounds per million Btu.	
N	Mi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.	
N	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
N	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.	
Y	(5) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must be less than the applicable emission limit for mercury.	Boiler No. 8 will comply with the Hg limit hrough fuel analysis.
Y	Where:	
Y	Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.	
Y	HGi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.	
Y	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
Y	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.	
Y	(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in Sec. 63.7545(e).	
Y	**Continuous Compliance Requirements**	
Y	**Sec. 63.7535 How do I monitor and collect data to demonstrate continuous compliance?**	
Y	(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by Sec. 63.7505(d).	

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Y	(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.	
Y	(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.	Boiler No. 8 will have a CEMS for CO.
Y	**Sec. 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?**	
Y	(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.	
Y	(1) Following the date on which the initial performance test is completed or is required to be completed under Sec. 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.	
Y	(2) You must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).	
N	(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of Sec. 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.	Boiler No. 8 will demonstrate compliance with HCl by performance testing.
N	(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to Sec. 63.7521(b).	
N	(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.	
N	(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of Sec. 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.	
Y	(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel type or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 5 of Sec. 63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of Sec. 63.7530 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Sec. 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in Sec. 63.7530(c).	
N	(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 10 of Sec. 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.	Boiler No. 8 will not choose to comply with the alternative TSM limit.

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to Sec. 63.7521(b).	
N	(ii) You must determine the new mixture of fuels that will have the highest content of TSM.	
N	(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 10 of Sec. 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.	
N	(6) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 6 of Sec. 63.7530. If the results of recalculating the maximum total selected metals input using Equation 6 of Sec. 63.7530 are higher than the maximum TSM input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Sec. 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in Sec. 63.7530(c).	Boiler No. 8 will not choose to comply with the alternative TSM limit.
Y	(7) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of Sec. 63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.	Boiler No. 8 will comply with the Hg limit through fuel analysis.
Y	(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to Sec. 63.7521(b).	
Y	(ii) You must determine the new mixture of fuels that will have the highest content of mercury.	
Y	(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of Sec. 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.	
N	(8) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 7 of Sec. 63.7530. If the results of recalculating the maximum mercury input using Equation 7 of Sec. 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Sec. 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in Sec. 63.7530(c).	Boiler No. 8 will comply with the Hg limit through fuel analysis.
N	(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions according to your SSMP, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.	Boiler No. 8 will not utilize a fabric filter.
Y	(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to Sec. 63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.	Boiler No. 8 will have a CEMS for CO.
Y	(i) You must continuously monitor carbon monoxide according to Sec. 63.7525(a) and 63.7535.	
Y	(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.	

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Y	(iii) Keep records of carbon monoxide levels according to Sec. 63.7555(b).	
Y	(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 Sec. 63.7550.	
Y	(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in Sec. 63.7505(e).	
Y	(d) Consistent with Sec. Sec. 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 Sec. 63.6(e).	
N	**Sec. 63.7541 How do I demonstrate continuous compliance under the emission averaging provision?**	Boiler No. 8 is not eligible for the emissions averaging provision.
N	(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.	
N	(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in Sec. 63.7522(f) and (g);	
N	(2) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system, maintain opacity at or below the applicable limit;	
N	(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and	
N	(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.	
N	(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (4) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.	
Y	**Notification, Reports, and Records**	
Y	**Sec. 63.7545 What notifications must I submit and when?**	
Y	(a) You must submit all of the notifications in Sec. Sec. 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.	
N	(b) As specified in Sec. 63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.	Boiler No. 8 will startup after Nov. 12, 2004.
N	(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by Sec. 63.9(b)(2).	
N	(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by Sec. 63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.	

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Y	(c) As specified in Sec. 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.	Boiler No. 8 must submit the initial notification within 15 days of startup.
Y	(d) If you arc required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.	Boiler No. 8 will submit the Notification of Intent at least 30 days prior to beginning testing.
Y	(e) If you are required to conduct an initial compliance demonstration as specified in Sec. 63.7530(a), you must submit a Notification of Compliance Status according to Sec. 63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to Sec. 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.	The Notification of Compliance Status will be submitted within 60 days following completion of the performance tests.
Y	(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.	
Y	(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.	
Y	(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.	
Y	(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.	
Y	(5) Identification of whether you plan to demonstrate compliance by emissions averaging.	
Y	(6) A signed certification that you have met all applicable emission limits and work practice standards.	
Y	(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.	
Y	(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.	
Y	(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.	
Y	**Sec. 63.7550 What reports must I submit and when?**	
Y	(a) You must submit each report in Table 9 to this subpart that applies to you.	
Y	(b) Unless the EPA Administrator has approved a different schedule for submission of reports under Sec. 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.	
Y	(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in Sec. 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in Sec. 63.7495.	
Y	(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in Sec. 63.7495.	

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.	
Y	(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.	
Y	(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.	
Y	(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.	
Y	(1) Company name and address.	
Y	(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.	
Y	(3) Date of report and beginning and ending dates of the reporting period.	
Y	(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.	
Y	(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.	
Y	(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of Sec. 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of Sec. 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of Sec. 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).	
Y	(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of Sec. 63.7530, the maximum TSM input operating limit using Equation 6 of Sec. 63.7530, or the maximum mercury input operating limit using Equation 7 of Sec. 63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.	
Y	(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.	
Y	(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in Sec. 63.10(d)(5)(i).	

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Y	(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.	
Y	(11) If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in Sec. 63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period.	
Y	(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.	
Y	(1) The total operating time of each affected source during the reporting period.	
Y	(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.	
Y	(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.	
Y	(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.	
Y	(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c) (1) through (10) of this section and the information required in paragraphs (e) (1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in Sec. 63.7505(d).	
Y	(1) The date and time that each malfunction started and stopped and description of the nature of the deviation (i.e., what you deviated from).	
Y	(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.	
Y	(3) The date, time, and duration that each CMS was out of control, including the information in Sec. 63.8(c)(8).	
Y	(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.	
Y	(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.	
Y	(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.	
Y	(7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.	
Y	(8) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.	
Y	(9) A brief description of the source for which there was a deviation.	
Y	(10) A brief description of each CMS for which there was a deviation.	
Y	(11) The date of the latest CMS certification or audit for the system for which there was a deviation.	
Y	(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.	

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NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.	
N	(g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in Sec. 63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.	Boiler No. 8 is not in the new gaseous fuel category.
N	(1) Company name and address.	
N	(2) Identification of the affected unit.	
N	(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.	
N	(4) Type of alternative fuel that you intend to use.	
N	(5) Dates when the alternative fuel use is expected to begin and end.	
Y	**Sec. 63.7555 What records must I keep?**	
Y	(a) You must keep records according to paragraphs (a)(1) through (3) of this section.	
Y	(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in Sec. 63.10(b)(2)(xiv).	
Y	(2) The records in Sec. 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.	
Y	(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in Sec. 63.10(b)(2)(viii).	
Y	(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.	
Y	(1) Records described in Sec. 63.10(b)(2) (vi) through (xi).	
Y	(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in Sec. 63.6(h)(7)(i) and (ii).	
Y	(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in Sec. 63.8(d)(3).	
Y	(4) Request for alternatives to relative accuracy test for CEMS as required in Sec. 63.8(f)(6)(i).	
Y	(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.	
Y	(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.	
Y	(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.	
Y	(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.	

ATTACHMENT USS-EU5-IV1b
NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	(2) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.	
Y	(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of Sec. 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 9 of Sec. 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.	
N	(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 6 of Sec. 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 10 of Sec. 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.	Boiler No. 8 is not choosing to comply with the alternative TSM limit.
Y	(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of Sec. 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of Sec. 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.	
N	(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.	Boiler No. 8 does not have a 10 percent capacity factor limitation.
N	(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.	
N	(2) Fuel use records for the days the boiler or process heater was operating.	
Y	**Sec. 63.7560 In what form and how long must I keep my records?**	
Y	(a) Your records must be in a form suitable and readily available for expeditious review, according to Sec. 63.10(b)(1).	
Y	(b) As specified in Sec. 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.	
Y	(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to Sec. 63.10(b)(1). You can keep the records off site for the remaining 3 years.	
Y	**Other Requirements and Information**	
Y	**Sec. 63.7565 What parts of the General Provisions apply to me?**	
Y	Table 10 to this subpart shows which parts of the General Provisions in Sec. Sec. 63.1 through 63.15 apply to you.	
Y	**Sec. 63.7570 Who implements and enforces this subpart?**	

ATTACHMENT USS-EU5-IV1b
NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.	
Y	(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.	
Y	(1) Approval of alternatives to the non-opacity emission limits and work practice standards in Sec. 63.7500(a) and (b) under Sec. 63.6(g).	
Y	(2) Approval of alternative opacity emission limits in Sec. 63.7500(a) under Sec. 63.6(h)(9).	
Y	(3) Approval of major change to test methods in Table 5 to this subpart under Sec. 63.7(e)(2)(ii) and (f) and as defined in Sec. 63.90.	
Y	(4) Approval of major change to monitoring under Sec. 63.8(f) and as defined in Sec. 63.90.	
Y	(5) Approval of major change to recordkeeping and reporting under Sec. 63.10(f) and as defined in Sec. 63.90.	
Y	**Sec. 63.7575 What definitions apply to this subpart?**	
Y	Terms used in this subpart are defined in the CAA, in Sec. 63.2 (the General Provisions), and in this section as follows:	
Y	**Annual capacity factor** means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.	
Y	**Bag leak detection system** means an instrument that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.	
Y	**Biomass fuel** means unadulterated wood as defined in this subpart, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.	
Y	**Blast furnace gas** fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.	
Y	**Boiler** means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.	
Y	**Coal** means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388-991 .\1\, ``Standard Specification for Classification of Coals by Rank \1\'' (incorporated by reference, see Sec. 63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.	
Y	**Coal refuse** means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.	
Y	**Commercial/institutional boiler** means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.	
Y	**Construction/demolition material** means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.	

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NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	**Deviation.** (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:	
Y	(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;	
Y	(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or	
Y	(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.	
Y	(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.	
Y	**Distillate oil** means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1" (incorporated by reference, see Sec. 63.14(b)).	
Y	**Dry scrubber** means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.	
Y	**Electric utility steam generating unit** means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.	
Y	**Electrostatic precipitator** means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.	
Y	**Fabric filter** means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.	
Y	**Federally enforceable** means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.	
Y	**Firetube boiler** means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.	
Y	**Fossil fuel** means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.	
Y	**Fuel type** means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.	
Y	**Gaseous fuel** includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.	
Y	**Heat input** means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.	
Y	**Hot water heater** means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210[deg]F (99[deg]C).	

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NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	**Industrial boiler** means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.	
Y	**Large gaseous fuel subcategory** includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.	
Y	**Large liquid fuel subcategory** includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.	
Y	**Large solid fuel subcategory** includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.	
Y	**Limited use gaseous fuel subcategory** includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.	
Y	**Limited use liquid fuel subcategory** includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.	
Y	**Limited use solid fuel subcategory** includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.	
Y	**Liquid fossil fuel** means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.	
Y	**Liquid fuel** includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.	
Y	**Minimum pressure drop** means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.	
Y	**Minimum scrubber effluent pH** means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.	
Y	**Minimum scrubber flow rate** means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.	
Y	**Minimum sorbent flow rate** means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.	
Y	**Minimum voltage or amperage** means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.	
Y	**Natural gas** means:	
Y	(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or	

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NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, "Standard Specification for Liquid Petroleum Gases" (incorporated by reference, see Sec. 63.14(b)).	
Y	**Opacity** means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.	
Y	**Particulate matter** means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.	
Y	**Period of natural gas curtailment or supply interruption** means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.	
Y	**Process heater** means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.	
Y	**Residual oil** means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1" (incorporated by reference, see Sec. 63:14(b)).	
Y	**Responsible official** means responsible official as defined in 40 CFR 70.2.	
Y	**Small gaseous fuel subcategory** includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.	
Y	**Small liquid fuel subcategory** includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.	
Y	**Small solid fuel subcategory** includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.	
Y	**Solid fuel** includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.	
Y	**Temporary boiler** means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.	
Y	**Total selected metals** means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.	
Y	**Unadulterated wood** means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.	
Y	**Waste heat boiler** means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.	

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NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	**Watertube boiler** means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.	
Y	**Wet scrubber** means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.	
Y	**Work practice standard** means any design, equipment, work practice, or operational standard, or combination thereof that is promulgated pursuant to section 112(h) of the CAA.	

FINAL DETERMINATION

PERMITTEE

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

PERMITTING AUTHORITY

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

PROJECT

United States Sugar Corporation - Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-035-AC
Boiler 8 - New Dry Cyclone Dust Collector

The Final Permit authorizes installation of a new dry cyclone dust collector to operate in parallel with two existing wet cyclone collectors on existing Boiler 8. The new equipment will be installed at the existing Clewiston Sugar Mill and Refinery, which is located in Hendry County at W.C. Owens Avenue and S.R. 832 in Clewiston, Florida.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on May 16, 2006. The applicant published the "Public Notice of Intent to Issue" in the Clewiston News on May 25, 2006. The Department received the proof of publication on June 14, 2006. No petitions for administrative hearings or extensions of time to petition for administrative hearing were filed.

COMMENTS

The Department received no comments on the Draft Permit.

CONCLUSION

The final action of the Department is to issue the Final Permit.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-035-AC
Boiler 8 – Dry Cyclone Dust Collector

Authorized Representative:
Mr. Neil Smith, Vice President of Sugar Processing Operations

Enclosed is Final Air Permit No. 0510003-035-AC, which authorizes installation of a new dry cyclone dust collector to operate in parallel with two existing wet cyclone collectors on existing Boiler 8. The new equipment will be installed at the existing Clewiston Sugar Mill and Refinery, which is located in Hendry County at W.C. Owens Avenue and S.R. 832 in Clewiston, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/19/06 to the persons listed:

Mr. Neil Smith, U.S. Sugar*
Mr. Don Griffin, U.S. Sugar
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office

Clerk Stamp

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

Mary L Harvey 6/19/06
(Clerk) (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE:

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Authorized Representative:
Mr. Neil Smith
Vice President of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-035-AC
Facility ID No. 0510003
SIC Nos. 2061, 2062
Permit Expires: June 1, 2008

PROJECT AND LOCATION

This permit authorizes installation of a new dry cyclone dust collector to operate in parallel with two existing wet cyclone collectors on Boiler 8. The new equipment will be installed at the existing Clewiston Mill and Refinery, which is located in Hendry County at W.C. Owens Avenue and S.R. 832 in Clewiston, Florida. The UTM coordinates are Zone 17, 506.1 km East, and 2956.9 km North.

STATEMENT OF BASIS

This air pollution construction 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 install the proposed equipment 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. This permit supplements all other existing valid air construction and operation permits for this emissions unit.

CONTENTS

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

Joe Kahn, Acting Director
Division of Air Resource Management

6/16/2006
(Date)

FACILITY AND PROJECT DESCRIPTION

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

Boiler 8 (EU-028) is a spreader-stoker boiler with a maximum heat input rate of 1030 MMBtu per hour. It fires bagasse as the primary fuel and wood chips as an alternate or supplemental fuel. Distillate oil is fired as a restricted alternate fuel for startup and supplemental uses. Particulate matter emissions from the boiler are currently controlled by two wet cyclone dust collectors as pre-controls followed by an electrostatic precipitator (ESP) as the primary control device. The project authorizes the installation of a new dry cyclone collector to operate in parallel with the two existing wet cyclone collectors. The purpose of the project is to reduce the exhaust flow through the two existing wet cyclone collectors and prevent carryover of water into the ESP control system.

REGULATORY CLASSIFICATION

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

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

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

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

NSPS: The facility operates units subject to a New Source Performance Standard in 40 CFR 60.

NESHAP: The facility operates units subject to a National Emissions Standard for Hazardous Air Pollutants in 40 CFR 63.

RELEVANT DOCUMENTS

The permit application is not a part of this permit; however, the information is specifically related to this permitting action and is on file with the Department. Permit No. PSD-FL-333 (as modified) is also an important relevant document.

1. Permitting Authority: The permitting Authority for this project is the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.

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

3. Appendices: The following Appendices are attached as part of this permit: Appendix A (Citation Format); and Appendix B (General Conditions).

4. 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.). 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.]

5. 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.]

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Title V Permit: This permit authorizes construction of an additional pre-control device for a permitted emissions unit. The installation of this equipment will not result in any substantive change to a Title V permit condition. The description of this new equipment will be included to the Title V renewal permit, which is currently under review by the Department. A separate Title V application is not required. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Boiler 8 (EU-028) - Dry Cyclone Collector

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
028	Boiler 8 is a spreader-stoker boiler with a maximum heat input rate of 1030 MMBtu per hour. It fires bagasse as the primary fuel and wood chips as an alternate or supplemental fuel. Distillate oil is fired as a restricted alternate fuel for startup and supplemental uses. Particulate matter emissions from the boiler are currently controlled by two wet cyclone dust collectors as pre-controls followed by an electrostatic precipitator (ESP) as the primary control device. A dry cyclone collector will be installed and operated in parallel along with the two existing wet cyclone collectors as a pre-control for the I.D. fan and ESP.

EQUIPMENT

1. Dry Cyclone Collector: The permittee is authorized to install a dry multiclone sand separator, or equivalent equipment, with a design particulate collection efficiency of 84%. The new equipment will be installed and operated in parallel along with the two existing wet cyclone collectors as a pre-control for the I.D. fan and electrostatic precipitator (ESP). In general, the new control device will consist of approximately 40 individual centrifugal–type cyclone collectors arranged in a grid of 8 by 5. Each collector will be 1.26 feet in diameter and 2.70 feet in height. The design and equipment selection is based on the following: a design flue gas flow rate of 90,000 acfm; a flue gas inlet temperature of 385° F; a flue gas inlet moisture content of 24% by volume; and an inlet particulate matter loading of 10,000 mg/Nm^3 (4.13 grains/dscf). The dry cyclone collector system will result in a pressure drop of approximately 3 inches, water column at the design flow rate. [Design; Rule 62-210.300, F.A.C.]
2. Records: The permittee shall notify the Compliance Authority within 15 days of completing construction. [Rule 62-4.070(3), F.A.C.]

CONTENTS

Appendix A. Citation Formats
Appendix B. General Conditions

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 CRF 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 (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not Applicable).

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.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333B
Project No. 0510003-030-AC
Boiler 8 - MACT Revision

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

Enclosed is Final Air Permit No. PSD-FL-333B, which authorizes the following revisions to the air construction permit for Boiler 8: incorporation of the final applicable NESHAP Subpart DDDDD provisions; EPA-approved alternate pH monitoring methods; revision of CO and PM emission standards consistent with final NESHAP Subpart DDDDD; authorization to fire wood chips as an alternate fuel; and authorization to fire incidental amounts of on-specification used oil generated on site. Boiler 8 operates at 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. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4/7/06 to the persons listed:

Mr. William A. Raiola, U.S. Sugar*
Mr. Don Griffin, U.S. Sugar
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office

Clerk Stamp

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

Barbara J. Friday (Clerk) 4/7/06 (Date)

FINAL DETERMINATION

PERMITTEE

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

PERMITTING AUTHORITY

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

PROJECT

United States Sugar Corporation - Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333B
Project No. 0510003-030-AC
Boiler 8 MACT Revisions

The Final Permit authorizes the following revisions to the air construction permit for Boiler 8: incorporation of the final applicable NESHAP Subpart DDDDD provisions; EPA-approved alternate pH monitoring methods; revision of CO and PM emission standards consistent with final NESHAP Subpart DDDDD; authorization to fire wood chips as an alternate fuel; and authorization to fire incidental amounts of on-specification used oil generated on site. Boiler 8 operates at 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.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on February 1, 2006. The applicant published the "Public Notice of Intent to Issue" in the Clewiston News on February 16, 2006. The Department received the proof of publication on March 9, 2006. No petitions for administrative hearings or extensions of time to petition for administrative hearing were filed.

COMMENTS

The applicant submitted minor comments on the Draft Permit. The following summarizes these comments and the Department's response.

1. Specific Condition 7e: For revised particulate matter emissions standard, add a reference to NESHAP Subpart DDDDD. *Response*: The reference was added.
2. Specific Conditions 20 and 22: For the electrostatic precipitator and wet cyclones monitoring requirements, add a reference to NESHAP Subpart DDDDD. *Response*: The reference was added.
3. Subsection B. Biomass Handling System: Two baghouse collectors have been installed to date. The systems have not performed well due to plugging and blinding of the bags from particle moisture. U.S. Sugar plans to abandon these control devices. Instead, the biomass conveyor systems have been almost completely enclosed to prevent fugitive dust emissions. *Response*: This is considered a substantial change and cannot be addressed in this final permit revision. However, the request can be made as part of the pending Title V renewal/revision application. Please include a full description of the methods and techniques used to confine/control fugitive emissions and address emission rates. No changes were made.

CONCLUSION

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

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE:

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

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

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333B
Project No. 0510003-030-AC
Facility ID No. 0510003
Permit Expires: July 1, 2007

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: incorporation of the applicable NESHAP Subpart DDDDD provisions; EPA-approved alternate pH monitoring methods; revision of CO emission standard; and authorization to fire wood chips as an approved fuel. 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

Section 1. General Information

Section 2. Administrative Requirements

Section 3. Emissions Units Specific Conditions

Section 4. Appendices

Michael G. Cooke, Director
Division of Air Resource Management

4-7-06
Effective Date

PROJECT DESCRIPTION

Boiler 8 (EU-028) is a new spreader-stoker boiler with a maximum heat input rate of 1030 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 dust collectors installed on the conveyor transfer points. The project will also potentially cause small increases in actual annual emissions from miscellaneous existing activities in the refinery.

REGULATORY CLASSIFICATION

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

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

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

PSD: The existing facility is a PSD-major facility as defined in Rule 62-212.400, F.A.C.

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

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

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Formats

Appendix B. General Conditions

Appendix C. Common Requirements

Appendix D. NSPS 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 original permit (PSD-FL-333), the revised permit (PSD-FL-333A), the current permit application (No. 0510003-030-AC), and the additional information provided to make it complete are not a part of this permit. However, the information in these documents is specifically related to this permitting action and is on file with the Department.

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. 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(6)(b), F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]
8. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
9. Relaxations of Restrictions on Pollutant Emitting Capacity. If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7,1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]

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

11. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit 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.]

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 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour averages). *Controls*: Particulate matter is controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. *Stack Parameters*: The stack will be 13.0 feet in diameter (maximum) and 199 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of 330° F and a volumetric flow rate of 400,000 acfm at 5.5% oxygen (225,000 dscfm at 7% oxygen). *CEMS*: Emissions of carbon monoxide and nitrogen oxides will be monitored and recorded by continuous emissions monitoring systems (CEMS).

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions of nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The final BACT determinations are presented in Appendix E of this permit. Boiler 8 is also subject to the following applicable requirements: Rule 62-296.405, F.A.C. (fossil fuel fired steam generators with more than 250 MMBtu per hour of heat input); Rule 62-296.410, F.A.C. (carbonaceous fuel burning equipment); 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. <u>Shutdown of Boiler 3</u>: No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of first fire in Boiler 8. Shakedown of the boiler is defined in Appendix H of this permit. During the authorized shakedown period:
   a. Boiler 8 may operate with the other existing boilers to ensure proper integration with the sugar mill and refinery. Any fuel oil fired in Boilers 1, 2, and 3 shall contain no more than 1.6% sulfur by weight.
   b. Boilers 3 and 8 may operate concurrently for no more than 90 individual days during which the combined steam production from Boilers 3 and 8 shall not exceed a daily average of 250,000 pounds per hour. After first fire and shakedown of Boiler 8, Boiler 3 shall be permanently shutdown prior to commencement of commercial operation of Boiler 8 or after completion of the crop season, whichever occurs first. For this facility, the sugarcane crop season is defined as October through April and the

off-season is defined as May through September.

No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of the permanent shutdown of Boiler 3 and of beginning commercial operation of Boiler 8. *{Permitting Note: Emissions decreases from the shutdown of Boiler 3 were used in the netting analysis to avoid PSD review of CO emissions for this project. The authorized shakedown period provides a reasonable period to start up the newly designed Boiler 8, test operations, and make necessary adjustments. A limited amount of concurrent operation is allowed because Boiler 8 is replacing Boiler 3 and must be fully tested during the crop season.}* [Design; Rule 62-212.400(2)(e) and (g), F.A.C.]

2. Construction of Boiler 8: The permittee is authorized to construct a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at design conditions of 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 550,000 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse 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 two wet cyclone collectors in parallel before the induced draft fan. Upon written approval of the Department, equivalent equipment may be installed.

   b. *ESP*: The permittee shall design, install, operate, and maintain an electrostatic precipitator (ESP) to remove particulate matter from the flue gas exhaust and achieve the particulate matter standards specified in this permit. The ESP shall include an automated rapping system that can adjust rapping frequency and intensity to prevent re-entrainment of fly ash. The ESP shall be on line and functioning properly whenever bagasse 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(5)(c), 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(5)(c), 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 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour average). The total maximum heat input from the oil burners is 562 MMBtu per hour (4161 gallons/hour). Boiler 8 shall not exceed the following operational levels.

   a. 12,000,000 pounds of steam per day (equivalent to 500,000 pounds of steam per hour and 936 MMBtu per hour, 24-hour averages);
   b. 3.6135 x 10^{+09} pounds of steam per consecutive 12 months (equivalent to 6,767,100 MMBtu per year);
   c. 99,864 gallons of distillate oil per day (equivalent to 13,488 MMBtu per day); and
   d. 6,073,600 gallons of distillate oil per consecutive 12 months (equivalent to 819,936 MMBtu per year).

   {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(2)(g), 62-210.200(PTE), F.A.C.; NSPS Subpart Db]

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

EMISSIONS STANDARDS

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

7. Standards Based on Stack Tests: The following emission standards apply when firing bagasse, 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(5)(c), F.A.C.]

   b. Carbon Monoxide (CO): To the extent practicable, short term emissions of carbon monoxide shall be controlled by implementing the good combustion and operating practices identified in Appendix F. [Rules 62-4.070(3), F.A.C.]

   c. Nitrogen Oxides (NOx): As determined by EPA Method 7E stack test, NOx emissions shall not exceed 0.14 lb/MMBtu and 131.0 pounds per hour. *{Permitting Note: This standard is an "initial demonstration standard" intended to show the capabilities of the SNCR system as designed. After the initial compliance test, subsequent compliance shall be demonstrated with the long-term CEMS-based standard specified in Condition 8b.}* [Rule 62-212.400(5)(c), F.A.C.]

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

   e. Particulate Matter (PM/PM_{10}): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.025 lb/MMBtu and 23.4 pounds per hour. [Rule 62-212.400(5)(c), 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 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400(5)(c), F.A.C.]

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

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(2)(g), F.A.C.]

b. Nitrogen Oxides (NOx): As determined by CEMS data, NOx emissions shall not exceed 0.14 lb/MMBtu based on a 30-day rolling average. [Rule 62-212.400(5)(c), F.A.C.]

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

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

9. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with the following. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working

day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

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

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

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

    a. *CO Emissions*: 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. *{Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}* [Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

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

EPA Method	Description of Method and Comments
CTM-027	Measurement of Ammonia Slip *{Note: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}*
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NOx Emissions (Instrumental)
9	Visual Determination of the Opacity

EPA Method	Description of Method and Comments
10	Measurement of Carbon Monoxide Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NOx, PM, and SO_2 Emission Rates
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

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

MONITORING REQUIREMENTS

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

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

    a. *Distillate Oil*: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain an oil flow meter with integrator. At the end of each day that oil is fired, the oil flow meter integrator shall be read and recorded in a written (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(5)(c), F.A.C.; NESHAP Subpart DDDDD]

19. <u>Alternate Opacity Monitoring Plan</u>: Based on written approval from EPA Region 4, the permittee shall employ the following alternate sampling procedures in lieu of the requirement to install and operate a COMS. The procedures apply to the firing of distillate oil.

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

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

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

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

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

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

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

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

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

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

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

        1) Based on the testing program, the plan shall specify the minimum total ESP secondary power input requirement (kW, 3-hour block average) that indicates effective performance.

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

        3) Continuous measurements shall be averaged into 15-minute blocks, which in turn will be averaged

into 1-hour and 3-hour block averages beginning at the top of each hour, excluding monitoring malfunctions, associated repairs, and required QA/QC activities.

4) Excursions below the minimum level specified require investigation and corrective action.
5) The proposed plan shall incorporate appropriate QA/QC requirements to ensure valid data.

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

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

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled NOx emissions monitoring and CEMS systems monitor availability for the previous quarter. If CO or NOx CEMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See Appendix G of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

FEDERAL REQUIREMENTS

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

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(2)(e) and (g), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive particulate matter, biomass conveyors shall be enclosed. Dust collectors shall be installed on the conveyor transfer points. 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]

EMISSIONS STANDARDS

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

TESTING REQUIREMENTS

4. Opacity Tests: Within 180 days of completing construction of the 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 each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the opacity standard. [Rules 62-212.400(5)(c) and 62-297.310(7)(a)4, F.A.C.]

REPORTS

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

Contents

Appendix A. Citation Formats
Appendix B. General Conditions
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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 and or Wood Chips
Appendix J. NESHAP Provisions

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(2), F.A.C.]

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 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.}

<u>§60.47b Emission Monitoring for Sulfur Dioxide</u>

(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.}

<u>§60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides</u>

(a) The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. *{Permitting Note: In lieu of the continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil.}*

§60.49b Reporting and Recordkeeping Requirements

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

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

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

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

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §60.42b, §60.43b, and §60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in Appendix B. *{Not applicable; see "Permitting Note" at end of section.}*

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

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

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

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

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

{Permitting Note: In lieu of the continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur. The permit also restricts the firing of distillate oil to an annual capacity factor of no more than 10%.}

Summary of Final BACT Determinations

Project Description

U.S. Sugar Corporation proposes to install a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 550,000 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. The maximum continuous steam production is 500,000 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour averages). Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used fire the primary fuel of bagasse (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.

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

Final BACT Determinations

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

Pollutant	Standards - Stack Test [a]	Standards – CEMS [b]
EU-027: Bagasse Handling System		
Opacity [c]	There shall be no visible emissions (≤ 5% opacity) from the dust collector outlets.	
EU-028: Boiler 8		
CO [d]	Good Combustion Practices	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.

Good Combustion and Operating Practices

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

Startup and Shutdown

1. Training: All operators and supervisors shall be properly trained to operate and maintain Boiler 8 as well as the pollution control and monitoring equipment in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions during startups, shutdowns, and malfunctions.

2. Boiler Startup: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately 4 to 5 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse (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).

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.}

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 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.

What This Subpart Covers

63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards

63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

General Compliance Requirements

63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the HCl and TSM standards?

Testing, Fuel Analyses, and Initial Compliance Requirements

63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

Continuous Compliance Requirements

63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

Notifications, Reports, and Records

63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

Other Requirements and Information

63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63

Table 1. Emission Limits and Work Practice Standards
Table 2. Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits
Table 3. Operating Limits for Boilers and Process Heaters with Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4. Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Emission Limits
Table 5. Performance Testing Requirements
Table 6. Fuel Analysis Requirements
Table 7. Establishing Operating Limits
Table 8. Demonstrating Continuous Compliance
Table 9. Reporting Requirements
Table 10. Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD

Appendix A. Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B. Applicability of General Provisions to Subpart DDDDD

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)).
	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 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	Semiannually according to the requirements in §63.7550(b).
	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)	

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.

ATTACHMENT USS-EU5-IV3

ALTERNATIVE METHODS OF OPERATION

Boiler No. 8

ATTACHMENT USS-EU5-IV3

ALTERNATIVE METHODS OF OPERATION

U.S. Sugar Clewiston Boiler No. 8 is permitted to fire carbonaceous fuel (bagasse and wood chips) as the primary fuel and distillate fuel oil as a restricted alternate fuel for startup and supplemental use. The boiler has a maximum steam production capacity of 500,000 lb/hr based on a maximum heat input rate of 936 MMBtu/hr (24-hour average). The sulfur content of distillate fuel oil is limited to 0.05 percent by weight. The operating hours of the boiler are not limited (8,760 hr/yr). Bagasse and wood chips can include incidental amounts of on-specification used oil.

EMISSION UNIT 12

FACILITY-WIDE UNREGULATED

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Facility-wide Unregulated

3. Emissions Unit Identification Number:

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

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
   See Attachment USS-EU12-A11 for a list of unregulated emission sources at the Clewiston and Bryant Mills.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Baghouses (6)**	
2. Control Device or Method Code(s): **018**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **8,760** hours/year	
6. Operating Capacity/Schedule Comment: **See Segment (Process/Fuel) Information - Section D**	

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

Emission Point Description and Type

<table>
<tr><td colspan="2">1. Identification of Point on Plot Plan or Flow Diagram:</td><td colspan="2">2. Emission Point Type Code:
3</td></tr>
<tr><td colspan="4">3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:</td></tr>
<tr><td colspan="4">4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:</td></tr>
<tr><td>5. Discharge Type Code:</td><td colspan="2">6. Stack Height:
feet</td><td>7. Exit Diameter:
feet</td></tr>
<tr><td>8. Exit Temperature:
°F</td><td colspan="2">9. Actual Volumetric Flow Rate:
acfm</td><td>10. Water Vapor:
%</td></tr>
<tr><td colspan="2">11. Maximum Dry Standard Flow Rate:
dscfm</td><td colspan="2">12. Nonstack Emission Point Height:
feet</td></tr>
<tr><td colspan="2">13. Emission Point UTM Coordinates...
Zone: East (km):
North (km):</td><td colspan="2">14. Emission Point Latitude/Longitude...
Latitude (DD/MM/SS)
Longitude (DD/MM/SS)</td></tr>
<tr><td colspan="4">15. Emission Point Comment:</td></tr>
</table>

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 7

1. Segment Description (Process/Fuel Type): **Food and Agriculture - Fugitive Emissions**		
2. Source Classification Code (SCC): **3-02-888-01**	3. SCC Units: **Tons Product**	
4. Maximum Hourly Rate: **446.8**	5. Maximum Annual Rate: **2,995,125**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Segment refers to bagasse throughput for entire Clewiston Mill bagasse handling system. Hourly rate refers to the maximum hourly rate during the crop season. Annual rate is based on the maximum bagasse usage of Boiler Nos. 1, 2, 4, 7, and 8.**		

Segment Description and Rate: Segment 2 of 7

1. Segment Description (Process/Fuel Type): **Food and Agriculture - Fugitive Emissions**		
2. Source Classification Code (SCC): **3-02-888-01**	3. SCC Units: **Tons Product**	
4. Maximum Hourly Rate: **241.4**	5. Maximum Annual Rate: **1,147,080**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Segment refers to bagasse throughput for entire Bryant Mill bagasse handling system. Hourly rate refers to the maximum hourly rate during the crop season. Annual rate is based on an operating maximum of 4,752 hours per year.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 7

1. Segment Description (Process/Fuel Type): **Sugar Cane Processing: Other not Classified**		
2. Source Classification Code (SCC): **3-02-015-99**	3. SCC Units: **Tons Material Processed**	
4. Maximum Hourly Rate: **33**	5. Maximum Annual Rate: **289,080**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Salt unloading and storage for Clewiston Molasses Plant Salt Silo.**		

Segment Description and Rate: Segment 4 of 7

1. Segment Description (Process/Fuel Type): **Manufacturing Industries; Mineral Products; Bulk Materials Storage Bins**		
2. Source Classification Code (SCC): **3-05-102-96**	3. SCC Units: **Tons Processed**	
4. Maximum Hourly Rate: **33**	5. Maximum Annual Rate: **5,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Lime unloading and storage at Clewiston Sugar Mill. Lime may be unloaded into the silos via railcar or truck.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 5 of 7

1. Segment Description (Process/Fuel Type): **Manufacturing Industries; Mineral Products; Bulk Materials Storage Bins**		
2. Source Classification Code (SCC): **3-05-102-96**	3. SCC Units: **Tons Processed**	
4. Maximum Hourly Rate: **25**	5. Maximum Annual Rate: **900**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Lime unloading and storage at Clewiston Water Treatment Plant.**		

Segment Description and Rate: Segment 6 of 7

1. Segment Description (Process/Fuel Type): **Manufacturing Industries; Mineral Products; Bulk Materials Storage Bins**		
2. Source Classification Code (SCC): **3-05-102-96**	3. SCC Units: **Tons Processed**	
4. Maximum Hourly Rate: **25**	5. Maximum Annual Rate: **1,500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Lime unloading and storage at Bryant Sugar Mill.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 7 of 7

1. Segment Description (Process/Fuel Type): **Manufacturing Industries; Mineral Products; Bulk Materials Storage Bins**		
2. Source Classification Code (SCC): **3-05-102-96**	3. SCC Units: **Tons Processed**	
4. Maximum Hourly Rate: **33**	5. Maximum Annual Rate: **5,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Limestone unloading and storage at Clewiston Molasses Plant.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
PM_{10}			NS
VOC			NS

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

(Optional for unregulated emissions units.)

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

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Applies to Clewiston Lime Storage Silo (EU 011), Clewiston Molasses Plant Limestone Silo (EU 030), Bryant Lime Storage Silo (EU 007), and Bryant Sugar Mill and Boiling House (EU008). Rule 62-296.320(4)(b)1., F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE05**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Applies to Clewiston Lime Storage Silo at the Water Treatment Plant (EU 010), the Clewiston Bagasse Handling System dust collector(s) (EU 027), Clewiston Molasses Plant Salt Silo bin vent filter, and the Clewiston New Lime Silos (EU 031).**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU12-I1** ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **USS-EU12-I3** ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: USS-EU12-IV1 ☐ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: _____ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID: _____
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [12]
Facility-wide Unregulated

Additional Requirements Comment

ATTACHMENT USS-EU12-A11

LIST OF UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES

Facility-Wide Unregulated

ATTACHMENT USS-EU12-A11a

LIST OF UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES

Clewiston Mill

The below listed emissions units and/or activities at the Clewiston Mill are neither "regulated emissions units" nor "insignificant emissions units".

EU ID No.	Brief Description of Emissions Units and/or Activity
011	**Lime Storage Silo** The Lime Storage Silo is equipped with a Mikro-Pulsaire Model 64S-8-20 baghouse filter. **(A)** Visible emissions limit is 20-percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]
010	**Lime Storage Silo at Water Treatment Plant** The Lime Storage Silo is equipped with a baghouse filter. **(A)** Visible emissions shall not exceed 5-percent opacity during silo loading. [Rule 62-296.320(4)(b)1., F.A.C., and Permit No. 0510017-001-AC]
---	**Molasses Plant Salt Silo** The Molasses Plant Salt Silo is equipped with an Industrial Accessories Company Model No. 587B-BVI-16:56 bin vent filter. **(A)** Visible emissions shall not exceed 5-percent opacity during silo loading, or from hoppers and other storage or conveying equipment. [Rule 62-297.620(4), F.A.C. and Permit No. 0510003-025-AC]
030	**Molasses Plant Limestone Silo** The Limestone Silo is equipped with a 16 bag fabric filter, IAC Model No. 58TB-BVI-16, Style 2, bin vent filter. **(A)** Visible emissions from the limestone silo and bin vent filter shall not exceed 20% opacity. [Rule 62-296.620(4), F.A.C., and Permit No. 0510003-033-AC]
031	**New Lime Silos (2)** Each of the two lime silos are controlled by a Smoot Model 60BV16 baghouse. The railcar unloading collection bin is controlled by a Smoot Model 60FR14 baghouse. **(A)** Emissions from each baghouse vent shall not exceed 5% opacity. [Rule 62-296.320(4)(b), F.A.C., and Permit No. 0510003-034-AC]

EU ID No.	Brief Description of Emissions Units and/or Activity	
	Sugar Mill and Boiling House	
	Bagacillo cyclones and handling system	Boiling house
	Centrifugals	Boiling house
	Crystallizer Cooling Towers	Boiling house
	Evaporator cleaning operations	Boiling house
	Evaporators	Boiling house
	Handling of raw sugar	Boiling house
	Juice heaters	Boiling house
	Lime slaker	Boiling house
	Mud belt presses	Boiling house
	Process tanks including: Batch, chemical neutralization, juice, clarified juice, clarifier, flocculant/coagulant mix, flash, hot liming, mingler, mixer, melter, mud mixing, mud receiving, pan feed, magma, mud waste muriatic acid, spent acid, sugar receiver, syrup storage, and alcohol storage (IPA) storage tanks.	Boiling house
	Vacuum mud filters and vacuum pumps	Boiling house
	Vacuum pans/receivers, condensers	Boiling house
	Cane mills	Sugar mill
	Cush-cush and DSM screens	Sugar mill
	Turbine vents	Sugar mill

ATTACHMENT USS-EU12-A11b

LIST OF UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES

Bryant Mill

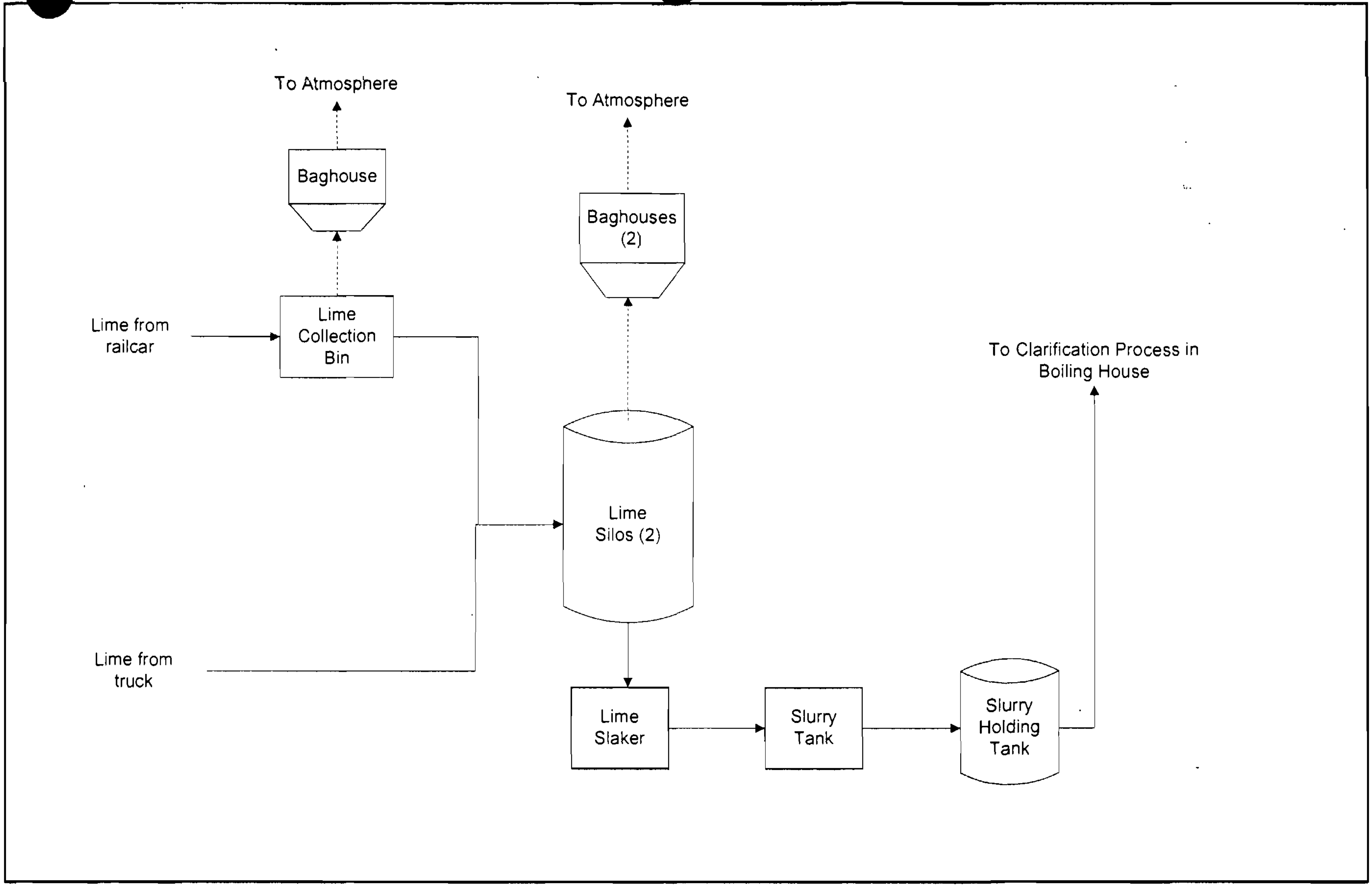
The below listed emissions units and/or activities at the Bryant Mill are neither "regulated emissions units" nor "insignificant emissions units".

EU ID No.	Brief Description of Emissions Units and/or Activity
007	**Lime Storage Silo** The Lime Storage Silo is equipped with a Sutor Built Series 400 baghouse filter. **(A)** Visible emissions limit is 20-percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]
008	**Sugar Mill and Boiling House** The sugar mill and boiling house consists of bagacillo cyclones and handling system; centrifugals; crystallizers; evaporator cleaning operations; evaporators with NCG vent; juice and clarified juice heaters (steam); lime slaker; mud filter vacuum pumps; processing tanks; rotary mud filters; and vacuum pans/receivers, and condensers; cane mills; cush-cush and DSM screens; and turbine vents. **(A)** Visible emissions limit is 20-percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]

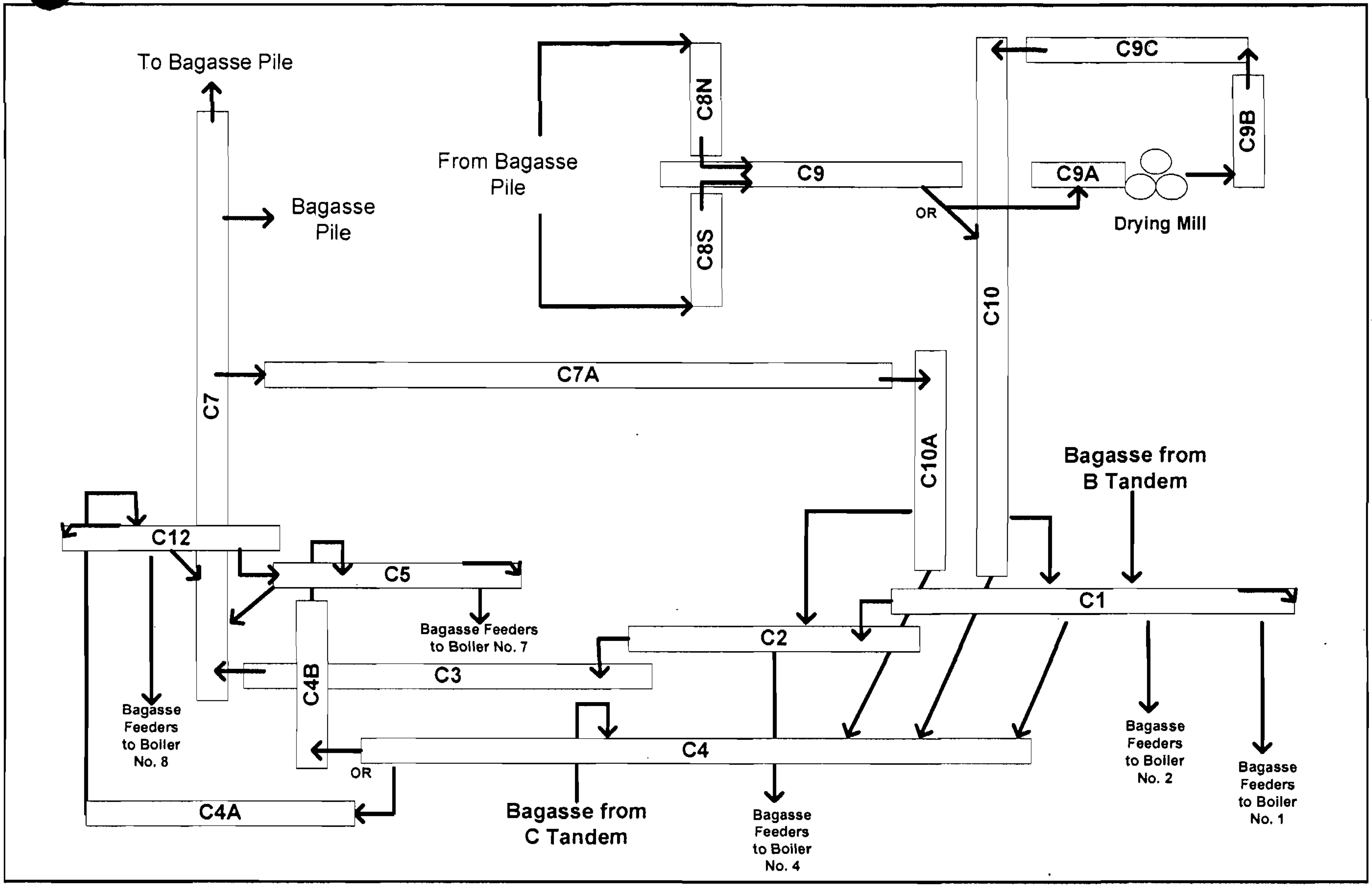
ATTACHMENT USS-EU12-I1

PROCESS FLOW DIAGRAM

Facility-Wide Unregulated



Attachment USS-EU12-I1a Lime System Flow Diagram U.S. Sugar Clewiston	**Process Flow Legend** Solid/Liquid Flow → Gas Flow - - - →	Filename: USS-EU12-I1a Date: 8/30/2006	Golder Associates



Attachment USS-EU2-I1b
Bagasse Conveying and Handling System
Flow Diagram
U.S. Sugar Clewiston

Process Flow Legend

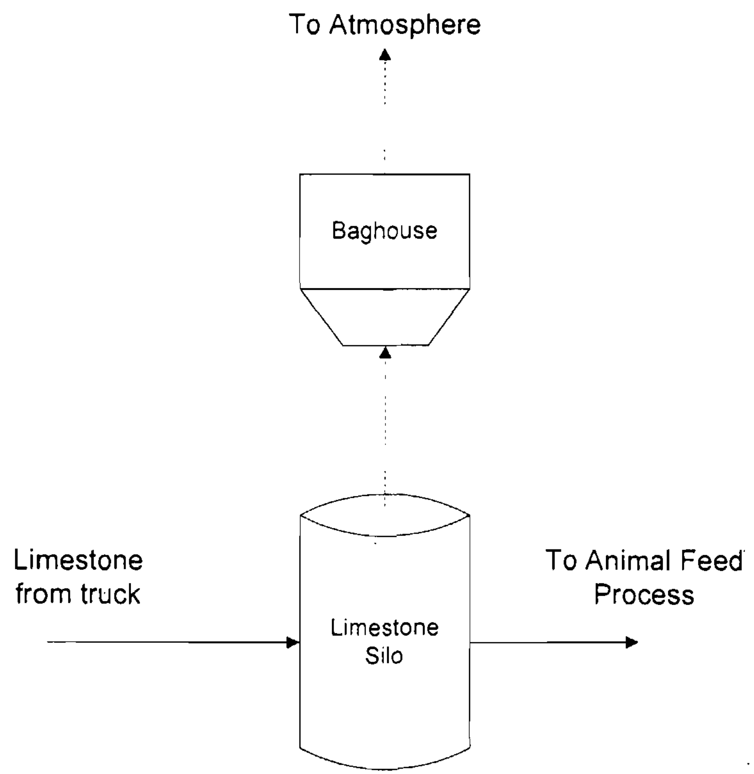
Solid/Liquid Flow ⟶

Gas Flow - - - - ➝

Filename: 0537540/4.1/RAI082806/USS-EU12-I1b.vsd

Date: 08/28/06

Golder Associates



Attachment USS-EU12-I1c
Molasses Plant Limestone Silo
Process Flow Diagram
U.S. Sugar Clewiston Mill
Clewiston, Florida

Process Flow Legend

Solid/Liquid Flow ⟶

Gas Flow - - - -→

Filename: 0537540/4.1/RAI082806/USS-EU12-I1c.vsd

Date: 06/29/05

Golder Associates

ATTACHMENT USS-EU12-I3

CONTROL EQUIPMENT PARAMETERS

Facility-Wide Unregulated

ATTACHMENT USS-EU12-I3a

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

Clewiston Molasses Plant Salt Silo

Bin Vent Filter

Parameter	Design Basis
Manufacturer/Model	Industrial Accessories Co. Bin Vent Model 58TB-BVI-16:S6
Volumetric air flow capacity (cfm)	750
Style	Pulse Cleaning
No. filter elements	16 bags
Filter Area (ft^2)	127
Air to Cloth Ratio	5.9 to 1
Bag Access	Top Removal
Clean air plenum access	Top Door
Filter Media	16 oz. Polyester Singed
Pressure drop (in. of H_2O)	2 to 4
Outlet Grain Loading (gr/dscf)	0.02

ATTACHMENT USS-EU12-I3b

CONTROL EQUIPMENT PARAMETERS FOR THE
LIMESTONE SILO BAGHOUSE AT U.S. SUGAR CLEWISTON (EU 030)

Manufacturer and Model No.	Industrial Accessories Company (IAC) 58TB-BVI-16, Style 2
Outlet Gas Temp (°F)	75
Outlet Gas Flow Rate (acfm)	750
Exhaust Gas Moisture Content (%)	1.0
Outlet Gas Flow Rate (dscfm)	733
Cleaning Method	Reverse Pulse Bin Vent
No. of bags	16
Bag Material	16 oz. Polyester Singed Fabric
Total Area of Filter Media (sq. ft)	126
Air to Cloth Ratio	5.95
Manufacturer's Guaranteed Outlet Loading (grains/acf)	0.02

Pollutants	Outlet Loading
Particulate Matter (lb/hr)	0.126

Note: Parameters based on manufacturers design specifications.

Sample calculations:
Outlet loading rate (lb/hr) = outlet gas flow rate (acfm) X
outlet loading rate (grains/acf) ÷ 7000 grains/lb X 60 min/hr

ATTACHMENT USS-EU12-13c

CONTROL EQUIPMENT PARAMETERS FOR EACH LIME SILO BAGHOUSE AT U.S. SUGAR CLEWISTON (EU 031)

Manufacturer and Model No.	Smoot Model 60BV16
Outlet Gas Temp (°F)	75
Outlet Gas Flow Rate (acfm)	476
Exhaust Gas Moisture Content (%)	1.0
Outlet Gas Flow Rate (scfm)	465
Cleaning Method	Reverse Pulse
No. of bags	16
Bag Material	16 oz. Polyester Singed Fabric
Total Area of Filter Media (sq. ft)	116
Air to Cloth Ratio	4.10
Manufacturer's Guaranteed Outlet Loading (grains/acf)	0.02

Pollutants	Outlet Loading
Particulate Matter (lb/hr)	0.080

Note: Parameters based on manufacturers design specifications as shown on the following page.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (acfm) X outlet loading rate (grains/acf) ÷ 7000 grains/lb X 60 min/hr

ATTACHMENT USS-EU12-13d

CONTROL EQUIPMENT PARAMETERS FOR THE
RAILCAR UNLOADING BAGHOUSE AT U.S. SUGAR CLEWISTON (EU 031)

Manufacturer and Model No.	Smoot Model 60FR14
Outlet Gas Temp (°F)	75
Outlet Gas Flow Rate (acfm)	477
Exhaust Gas Moisture Content (%)	1.0
Outlet Gas Flow Rate (scfm)	466
No. of bags	14
Bag Material	16 oz. Polyester Singed Fabric
Total Area of Filter Media (sq. ft)	104
Air to Cloth Ratio	4.9
Manufacturer's Guaranteed Outlet Loading (grains/acf)	0.02

Pollutants	Outlet Loading
Particulate Matter (lb/hr)	0.080

Note: Parameters based on manufacturers design specifications as shown on the following page.

Sample calculations:
Outlet loading rate (lb/hr) = outlet gas flow rate (acfm) X outlet loading rate (grains/acf) ÷ 7000 grains/lb X 60 min/hr

ATTACHMENT USS-EU12-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Facility-Wide Unregulated

CLEWISTON

WATER TREATMENT PLANT LIME SILO

(EU 010)

Department of Environmental Protection

Lawton Chiles
Governor

Mailing Address:
Post Office Box 2549
Fort Myers, Florida 33902-2549

Virginia B. Wetherell
Secretary

DEC 1998 RECEIVED ENGINEERING

NOTICE OF PERMIT ISSUANCE

December 3, 1998

CERTIFIED MAIL #P 506 066 482
RETURN RECEIPT REQUESTED

Post-it® Fax Note 7671	Date 8-28-9	# of pages ▶ 1/
To David Butt	From Don Griffin	
Co./Dept.	Co.	
Phone #	Phone #	
Fax #	Fax #	

In the Matter of an Application
for Permit by:

Lawrence D. Worth
United States Sugar Corporation
Post Office Drawer 1207
Clewiston, Florida 33440

DEP File No. 0510017-001-AO
Hendry County - AP

Enclosed is Permit Number 0510017-001-AO to United States Sugar Corporation to operate a Lime Silo at Clewiston Water Treatment Plant, issued under section(s) 403.087 of the Florida Statutes.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;

(c) A statement of how and when petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and

(f) A demand for relief.

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

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

Mediation is not available in this proceeding.

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

Executed in Fort Myers, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

David M. Knowles

David M. Knowles, P.E.
District Air Program Administrator
Post Office Box 2549
Fort Myers, Florida 33902-2549
(941) 332-6975

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT ISSUANCE and all copies were mailed by certified mail before the close of business on December 4, 1998 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT

FILED, on this date under section 120.52(7) Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk)	12-4-98 (Date)

DMK/JRS/jw

Copies furnished to:

Jose Lopez, P.E.

Department of
Environmental Protection

Lawton Chiles
Governor

Mailing Address:
Post Office Box 2549
Fort Myers, Florida 33902-2549

Virginia B. Wetherell
Secretary

PERMITTEE:
United States Sugar Corporation
Post Office Drawer 1207
Clewiston, Florida 33440

I. D. No.: 0510017
Permit Number: 0510017-001-AO
Date of Issue: December 3, 1998
Expiration Date: December 3, 2003
County: Hendry
Latitude: 26 ° 44 ' 15" N
Longitude: 80° 56 ' 07 " W
Section/Town/Range: 21/43S/34E
Project: Lime Silo at Clewiston
Water Treatment Plant

This permit is issued under the provisions of Chapter 403.087, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Rules 62-296, 62-297 and 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Operate a lime silo at Clewiston Water Treatment Plant.

The facility is located at 1731 South W. C. Owen Avenue, Clewiston, Florida.

PERMITTEE:
United States Sugar Corporation

I. D. No.: 0510017
Permit/Cert. No.: 0510017-001-AO
Date of Issue: December 3, 1998
Expiration Date: December 3, 2003

SPECIFIC CONDITIONS:

FACILITY OPERATIONS

1. All fugitive dust generated at this site shall be adequately controlled. [Reference Rule 62-296.320(4)(c), F.A.C.]

2. This facility shall be operated in such a fashion so as to preclude objectionable odors. [Reference Rule 62-296.320(2), F.A.C.]

3. The permittee shall not allow any person to circumvent any pollution control device nor allow the emissions of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

CONDITIONS OF COMPLIANCE

4. Visible emissions shall not exceed 5% opacity during silo loading. [Reference Rule 62.297.620(4), F.A.C.]

SPECIFIC CONDITIONS:

REQUIRED TESTING

5. Visible emissions test are required to show continuing compliance with the standards of the Department. The test results must provide reasonable assurance that the unit is capable of compliance at the permitted maximum operating rate. Tests shall be conducted in accordance with EPA Method Nine as published in 40 CFR-60 Appendix A, or State approved equivalent method. Such tests shall be conducted once per year. The Department shall be notified at least 15 days prior to testing to allow witnessing. [Reference Rule 62-297.310(7)]

6. Notification of the Department prior to any required testing shall include as a minimum: the date and time of the test, the exact location of the test, and the name and telephone number of the contact person at the site. [Reference Rule 62-297.310(7)(a)9, F.A.C.]

PERMITTEE:
United States Sugar Corporation

I. D. No.: 0510017
Permit/Cert. No.: 0510017-001-AO
Date of Issue: December 3, 1998
Expiration Date: December 3, 2003

SPECIFIC CONDITIONS:

GENERAL CONDITIONS:

7. An integral part of this permit is the attached 15 General Conditions.
[Rule 62-4.160, F.A.C.]

NOTE: In the event of an emergency the permittee shall contact the Department by calling (850) 413-9911. During normal business hours, the permittee shall call (941) 332-6975.

Issued this 3rd day of December, 1998.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

David M. Knowles

David M. Knowles, P.E.
District Air Program Administrator

DMK/JRS/jw

__9__ Pages Attached

PERMITTEE:
United States Sugar Corporation

I. D. No.: 0510017
Permit/Cert. No.: 0510017-001-AO
Date of Issue: December 3, 1998
Expiration Date: December 3, 2003

GENERAL CONDITIONS:

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 any 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 of 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 any 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 and 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.

GENERAL CONDITIONS:

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 any 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 non-compliance, 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 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 Section 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.

GENERAL CONDITIONS:

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-30.300, 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:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Compliance with New Source Performance Standards (NSPS)

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 for 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:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used;
- 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 the 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.

CLEWISTON

MOLASSES PLANT SALT SILO

GOLDER ASSOCIATES INC.

DEC 27 2004

GAINESVILLE

Department of Environmental Protection

Jeb Bush
Governor

South District
P.O. Box 2549
Fort Myers, Florida 33902-2549

Colleen M. Castille
Secretary

NOTICE OF FINAL PERMIT

December 21, 2004

CERTIFIED MAIL 7004 0750 0003 9120 4226
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

William A. Raiola, Senior Vice President
Sugar Processing Operations
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Hendry County - AP
U.S. Sugar Clewiston Mill
DEP File No. 0510003-025-AC

Enclosed is Final Permit Number 0510003-025-AC. This permit authorizes the United States Sugar Corporation to construct one (1) Bin Vent, 16-bag dust collector onto an existing molasses plant storage silo. The dust collector is defined as Industrial Accessories Company (IAC) Model No. 58TB-BVI-16:S6. The maximum process rate for salt loading is 33 tons per hour and the particulate matter emissions are defined at 0.13 lb/hr and 0.57 tons/year. This facility if located at W.C. Owens Avenue and S.R. 832, Clewiston, Florida, 33440, Hendry County, Florida. This permit is issued pursuant to Section 403.087, Florida Statutes.

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

Executed in Fort Myers, Florida

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jon M. Iglehart
Acting Director of
District Management
Post Office Box 2549
Fort Myers, Florida 339002-2549
(239) 332-6975

JMI/CE/jw

NOTICE OF FINAL PERMIT
U.S. Sugar Corporation
Clewiston Mill
DEP File No. 0510003-025-AC
December 21, 2004

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on December 21, 2004 to the persons listed:

William A. Raiola, Senior Vice President*
David Buff, Golder Associates, Inc. ✓

Clerk Stamp

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

[illegible] 12/21/04
(Clerk) (Date)

Department of Environmental Protection

South District
P.O. Box 2549
Fort Myers, Florida 33902-2549

Jeb Bush
Governor

Colleen M. Castille
Secretary

PERMITTEE:
U.S. Sugar Corporation
Clewiston Mill
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Facility I.D. No. 0510003
Permit Number: 0510003-025-AC
Date of Issue: December 21, 2004
Expiration Date: December 21, 2009
County: Hendry
Latitude: 26° 44' 06" N
Longitude: 80° 56' 19" W
Project: Molasses Plant, Salt Silo Vent Filter Installation

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Rules 62-4, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The permit authorizes the construction of one (1) Bin vent, 16 bag fabric filter dust collector, Industrial Accessories Company (IAC) Model No. 58TB-BVI-16:S6 onto an existing molasses plant salt storage silo. The maximum process rate for salt loading is 33 tons per hour and the particulate matter emissions are defined at 0.13 lb/hr and 0.57 tons/year.

The facility is located at the U.S. Sugar Corporation, Clewiston Mill, W.C. Owens Avenue and S.R. 832 Clewiston, Florida 33440, Hendry County.

Pertinent Documents	**Dated**
Construction Application	August 31, 2004
Notice of Intent to issue:	October 28, 2004

SPECIFIC CONDITIONS:

This permit addresses the following emissions unit:

E. U. ID No.	**Emissions Unit Description**
001	Dust collector

The Emissions Unit 001 is a sixteen (16) bag, fabric filter dust collector, IAC Model No. 58TB-BVI-16:S6. It utilizes an air backwash for bag cleaning. The volumetric airflow is 750 acfm, exit temperature is ambient (77 degrees F.), and the stack or emissions release height is 33 feet. This air pollution device is designed to filter particulate matter emissions.

Essential Potential to Emit (PTE) Parameters:

1. Permitted Capacity. The operating rate of the salt silo is approximately 33 tons per hour. [Rules 62-4.160(2) and 62-213.200(PTE), F.A.C.]

2. Hours of Operation. The hours of operation for this emissions unit are not limited. [Rules 62-4.070(3), 62-4.160(2), and 62.210.200(PTE), F.A.C.]

Emission Limitations and Standards:

3. Objectionable Odor Prohibited. The Permittee shall not cause, suffer, allow, or permit the discharge of air Pollutants, which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

4. Circumvention: The owner or operator 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.]

5. Unconfined Emissions of Particulate Matter: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement, transportation of materials, construction, alteration, demolition or wrecking, or industrially related activities such as loading, storing or handling, without taking reasonable precautions to prevent such emissions. Reasonable precautions may include but are not limited to the following:

a. Paving and maintenance of roads, parking areas and yards.
b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
c. Application of asphalt, water, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
d. Removal of particulate matter from roads and other paved areas under control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne.
e. Landscaping or planting vegetation.

SPECIFIC CONDITIONS:

f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.

g. Confining abrasive blasting where possible.

h. Enclosure or covering of conveyor systems.

[Rule 62-296.320,F.A.C.]

6. Discharges: There shall be no discharges of liquid effluents or contaminated runoff from the plant site.
[Rule 62-4.070(3), F.A.C.]

7. Visible emissions shall not exceed 5% opacity during silo loading, or from hoppers and other storage, or from conveying equipment.
[Rule 62.297.620(4), F.A.C.]

Test Methods and Procedures:

8. Visible emissions test is required to show continuing compliance with the standards of the Department. The test results must provide reasonable assurance that the unit is capable of compliance at the permitted maximum operating rate. Tests shall be conducted in accordance with EPA Method 9 as published in 40 CFR-60 Appendix A, or State approved equivalent method. The dust collector exhaust point shall be tested for visible emissions within 60 days after completion of construction.
[Rule 62-297.310(7), F.A.C.]

9. This dust collector exhaust port shall be tested by a certified observer in accordance with EPA Method 9 for a minimum of 30 minutes or, if the operation is normally completed in less that 30 minutes and does not recur within that time, the test shall last for the length of the silo loading operation.
[Rule 62-297.310(4)(a) and Rule 62-297.401(9)(a) F.A.C.]

10. A visible emissions test shall be conducted while loading the silo at a rate that is representative of the normal silo-loading rate. Each test report shall state the actual silo-loading rate during emissions testing.
[Rule 62-4.070(3) F.A.C.]

11. The permittee shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin. The permittee shall provide written notification of the date, time and location of each test, and provide the name, company and telephone number of the person conducting the test.
[Rule 62-297.310(7)(a)(9), F.A.C.]

SPECIFIC CONDITIONS:

Monitoring of Operations:

12. Operation procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. Any time this unit is found to be performing inadequately because of overloading, neglect, or other reasons, the owner shall discontinue its use until measures are provided to correct the cause of such performance.
[Rule 62-4.070(3), F.A.C.]

Recordkeeping and Report Requirements:

13. 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 owner or operator shall notify the Department as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: Pertinent information as to the cause of the problem, the steps being taken to correct the problem and prevent future recurrence, and where applicable, the owners intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability to comply with the conditions of this permit or regulations.
[Rule 62-4.130, F.A.C.]

14. 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 test. The required test report shall be filed with the Department as soon as practical, but no later than forty five (45) days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions units tested and the test procedures used to allow the Department to determine if the test was properly conducted and the results properly computed.
[Rule 62-297.310(8)(b), F.A.C.]

15. A record shall be kept of each time the silo is loaded and the tonnage of product for each loading. In addition, all inspections and maintenance work on the silo and/or bin vent filter shall be recorded.
[Rule 62-4.160, F.A.C.]

16. Changes/Modifications: The owner or operator shall submit to the Department, for review, any changes in, or modifications to: the method of operations, process or pollution control equipment, increase in hours of operation, equipment capacities, or any change which would result in an increase in potential/actual emissions. Depending upon the size and scope of the modification, it may be necessary to submit an application for, and obtain, an air construction permit modification prior to making the desired change. Routine maintenance of equipment will not constitute a modification of this permit.
[Rule 62-4.030, 62-210.300 and 62-4.070(3), F.A.C.]

PERMITTEE:
U.S. Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-025-AC
Date of Issue: December 21, 2004
Expiration Date: December 21, 2009

SPECIFIC CONDITIONS:

17. All recorded data shall be maintained on file at the facility for a period of five (5) years. [Rule 62-4.070(3) F.A.C.]

General Conditions:

18. An integral part of this permit is the attached fifteen (15) paragraphs of the General Conditions and Construction Application noted as "Pertinent Documents".

NOTE: In the event of an emergency the permittee shall contact the Department by calling (850) 413-9911. During normal business hours, the permittee shall call **(239) 332-6975.**

Issued this 21st day of December 2004.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jon M. Iglehart
Acting Director of
District Management
Post Office Box 2549
Fort Myers, Florida 33902-2549
(239) 332-6975

JMI/CE/jw

PERMITTEE:
U.S. Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-025-AC
Date of Issue: December 21, 2004
Expiration Date: December 21, 2009

GENERAL CONDITIONS:

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 or 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 any 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 any 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 any 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.

GENERAL CONDITIONS:

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 noncompliance 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 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 incorporates the following previously issued determinations:

(a) Determination of Best Available Control Technology (not applicable);

(b) Determination of Prevention of Significant Deterioration (not applicable); and

(c) Compliance with New Source Performance Standards (not applicable).

PERMITTEE:
U.S. Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-025-AC
Date of Issue: December 21, 2004
Expiration Date: December 21, 2009

GENERAL CONDITIONS:

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 date's 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.

CLEWISTON

MOLASSES PLANT LIMESTONE SILO
(EU 030)

Department of
Environmental Protection

GOLDER ASSOCIATES INC.

SEP - 9 2005

GAINESVILLE

Jeb Bush
Governor

South District
P.O. Box 2549
Fort Myers, Florida 33902-2549

Colleen M. Castille
Secretary

NOTICE OF FINAL PERMIT

September 6, 2005

CERTIFIED MAIL 7004 1160 0000 5510 1731
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by

William A. Raiola, Senior Vice President
Sugar Processing Operations
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Hendry County - AP
United States Sugar Corporation
Clewiston Mill
DEP File No. 0510003-033-AC

Enclosed is Final Permit Number 0510003-033-AC. This permit authorizes United States Sugar Corporation to construct one (1) Limestone storage silo and one (1) bin vent filter for control of PM/PM10 emissions, at the facility Molasses Plant. The silo is filled pneumatically by truck, and is discharged by gravity to a mechanical auger. The potential PM emissions are 0.55 tons/year. This location is at the U.S. Sugar Clewiston Mill, located at W.C. Owens Ave. and S.R. 832, Clewiston, Hendry County, Florida. This permit is issued pursuant to Section(s) 403.087, Florida Statutes.

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

Executed in Fort Myers, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jon M. Iglehart
Director of
District Management
Post Office Box 2549
Fort Myers, Florida 33902-2549
(239) 332-6975

NOTICE OF FINAL PERMIT
United States Sugar Corporation
Clewiston Mill
DEP File No. 0510003-033-AC
September 6, 2005

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on September 6, 2005 to the person(s) listed:

William A. Raiola, Senior Vice President, Sugar Processing Operations*
David A. Buff, P.E.

Clerk Stamp

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

(Clerk) (Date) 9/6/2005

JMI/CBE/jw

Department of Environmental Protection

Jeb Bush
Governor

South District
P.O. Box 2549
Fort Myers, Florida 33902-2549

Colleen M. Castille
Secretary

PERMITTEE:
United States Sugar Corporation
Clewiston Mill
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Facility I.D. No.: 0510003
Permit Number: 0510003-033-AC
Date of Issue: September 6, 2005
Expiration Date: September 6, 2010
County: Hendry
Latitude: 26° 44' 06" N
Longitude: 80° 56'19 " W
Project: New Limestone Storage Silo

This permit is issued under the provisions of Chapter 403.087, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Rules 62-4, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the Department and made a part hereof and specifically described as follows:

This permit authorizes the construction of one (1) Limestone Storage Silo complete with one (1) Bin Vent Filter for control of PM/PM10 emissions, at the Molasses Plant site of the U.S. Sugar Clewiston Mill, located at W.C. Owens Avenue and S.R. 832, Clewiston, Hendry County, Florida. The potential PM emissions are 0.55 tons/year.

Pertinent Documents	Dated
Application for Construction Permit	July 8, 2005
Affidavit of Newspaper Public Notice	August 19, 2005

SPECIFIC CONDITIONS:

This permit addresses the following emissions unit:

E. U. ID No.	Emissions Unit Description
030	Limestone Storage Silo with Bin Vent Filter

The emission unit is one (1) limestone storage silo with a 16 bag fabric filter, IAC Model No. 58TB-BVI-16, style 2, bin vent filter.

Operations

1. Permitted Capacity. The process/operation rate shall not exceed 5,000 tons per year throughput.
[Rules 62-4.160(2), and 62-210.200(PTE), F.A.C.]

2. Method of Operation. Limestone is delivered by truck and pneumatically (750 acfm) off-loaded into the storage silo at a rate of approximately 1,100 pounds per minute (33 tons per hour) with a maximum throughput rate of 5,000 tons per year (TPY). Limestone will be unloaded from the silo via gravity drop into a mechanical auger where it will be conveyed to the Molasses Plant process.

3. Hours of Operation. The hours of operation for this emissions unit are not restricted.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

4. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants, which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

5. Circumvention. The owner or operator 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.]

6. Unconfined Emissions of Particulate Matter. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions include the following:

   a. Paving and maintenance of roads, parking areas and yards.
   b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
   c. Application of asphalt, water, chemicals, or other dust suppressants to unpaved roads, yards, open stock piles, and similar activities.

SPECIFIC CONDITIONS:

d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne.

e. Landscaping or planting of vegetation.

f. Use of hoods, fans, filters, and similar equipment to contain, capture, and/or vent particulate matter.

g. Confining abrasive blasting where possible.

h. Enclosure or covering of conveyor systems.

[Rule 62-296.320(4)(c), F.A.C.]

7. Any activity performed by the permittee at the plant site shall not result in the discharge of liquid effluent or contaminated runoff to surface or ground water without prior approval from the Department.
[Rule 62-4.070, F.A.C.]

8. Operating Procedures. Operation procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufactures. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. Any time this unit is found to be performing inadequately because of overloading, neglect, or other reasons, the permittee shall discontinue its use until measures are provided to correct the cause of such performance.
[Rule 62-4.070(3), F.A.C.]

9. Changes/Modifications. The owner or operator shall submit to the Department, for review any changes in, or modifications to: the method of operations; process or pollution control equipment; increase in hours of operation; equipment capacities; or any change which would result in an increase in potential/actual emissions. Depending on the size and scope of the modification, it may be necessary to submit an application for, and obtain, an air construction permit prior to making the desired change. Routine maintenance of equipment will not constitute a modification of this permit.
[Rule 62-4.030, 62-210.300 and 62-4.070(3), F.A.C.]

10. The applicant shall retain a Florida registered Professional Engineer for the inspection of the construction of this project. Upon completion, the engineer shall inspect for conformity to construction permit, applications, and associated documents. An "Application for Air Permit - Non Title V Source" (DEP Form 62-210.900(3)) shall be submitted with the appropriate fee, compliance test results, and the Florida Registered Professional Engineer sealed results within 60 days after completion of construction for the limestone storage silo.
[Rules 62-4.070(3), 62-4.210, 62-4.220, and 62-210.300(1), F.A.C.]

11. Visible emissions from the limestone silo and bin vent filter shall not exceed 20% opacity.
[Rule 62-296.620(4), F.A.C.]

SPECIFIC CONDITIONS:

12. The maximum estimated emissions from emission unit EU-030 shall not exceed:

PM	PM10
0.55 tons/year	0.55 tons/year
(0.126 lb/hour)	(0.126 lb/hour

Test Methods and Procedures

13. Visible emissions test is required to show continuing compliance with the standards of the Department. The test results must provide reasonable assurance that the unit is capable of compliance at the permitted maximum operating rate. Tests shall be conducted in accordance with EPA Method 9 as published in 40 CFR-60 Appendix A, or State approved equivalent method. The bin vent filter exhaust point shall be tested for visible emissions within 60 days after completion of construction.
[Rule 62-297.310(7), F.A.C.]

14. The bin vent filter exhaust point shall be tested by a certified observer in accordance with EPA Method 9 for a minimum of 30 minutes or, if the operation is normally completed in less than 30 minutes and does not recur within that time, the test shall last for the length of the silo loading operation.

[Rule 62-297.310(4)(a) and rule 62-297.401(9)(a) F.A.C.]

15. A visible emissions test shall be conducted while loading the limestone storage silo at a rate that is representative of the normal silo-loading rate. Each test report shall state the actual silo-loading rate during emissions testing. The maximum loading rate is 33 tons/hour.
[Rule 62-4.070(3), F.A.C.]

16. The permittee shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall provide written notification of the date, time, and location of each test; the name and telephone number of the facility's contact person who will be responsible for coordinating the test; and the name, company, and telephone number of the person conducting the test.
[Rule 62-297.310(7)(a)(9), F.A.C.]

Record Keeping and Reporting Requirements

17. 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 the Department as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: Pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the permittee'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 and the regulations.
[Rule 62-4.130, F.A.C.]

PERMITTEE:
United States Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-033-AC
Date of Issue: September 6, 2005
Expiration Date: September 6, 2010

SPECIFIC CONDITIONS:

18. The permittee 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 units tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed.
[Rule 62-297.310(8)(b), F.A.C.]

19. A record shall be kept of each time the silo is loaded and the tonnage of limestone for each loading. In addition, all inspections and maintenance work on the limestone storage silo and or bin vent filter shall be recorded.
[Rule 62-4.070(3), F.A.C.]

20. All recorded data shall be maintained on file at the facility for a period of five years.
[Rule 62-4.070(3), F.A.C.]

General Conditions:

An integral part of this permit is the attached 15 General Conditions.
[Rule 62-4.160, F.A.C.]

NOTE: In the event of an emergency the permittee shall contact the Department by calling (850) 413-9911. During normal business hours, the permittee shall call **(239) 332-6975.**

Issued this 6th day of September 2005.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jon M. Iglehart
Director of
District Management
Post Office Box 2549
Fort Myers, Florida 33902-2549
(239) 332-6975

JMI/CBE/jw

PERMITTEE:
United States Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-033-AC
Date of Issue: September 6, 2005
Expiration Date: September 6, 2010

GENERAL CONDITIONS:

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 or 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 any 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 any 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 any 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.

PERMITTEE:
United States Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-033-AC
Date of Issue: September 6, 2005
Expiration Date: September 6, 2010

GENERAL CONDITIONS:

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 noncompliance 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 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 incorporates the following previously issued determinations:

(a) Determination of Best Available Control Technology (not applicable);

(b) Determination of Prevention of Significant Deterioration (not applicable); and

(c) Compliance with New Source Performance Standards (not applicable).

PERMITTEE:
United States Sugar Corporation
Clewiston Mill

Facility I.D. No.: 0510003
Permit Number: 0510003-033-AC
Date of Issue: September 6, 2005
Expiration Date: September 6, 2010

GENERAL CONDITIONS:

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 date's 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.

CLEWISTON

NEW LIME SILOS
(EU 031)

lime silos, transfer system, lime slakers (2) Boiling House

FINAL DETERMINATION

PERMITTEE

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

PERMITTING AUTHORITY

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

PROJECT

Air Permit No. 0510003-03A-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery

This permit authorizes the installation of two new lime silos, truck and railcar pneumatic unloading and conveying equipment, three associated baghouse control systems, and a lime slaker system (as necessary). The new equipment will be installed at the existing Clewiston Mill and Refinery, which is located in Hendry County at 111 Ponce DeLeon Avenue in Clewiston, Florida.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on November 16, 2005. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on December 8, 2005. The Department received proof of publication on December 15, 2005. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

No comments on the Draft Permit were received from the public or the Department's South District Office. The applicant had the following comments.

Page 4 of 4, Condition 3: Should the rule citation for the alternative visible emissions VE limit of 5% be Rule 297.620, F.A.C.?

Response: The visible emissions standard for control by baghouse is established pursuant to the authority in Rule 62-4.070(3), F.A.C. A properly maintained and operated baghouse should not have visible emissions exceeding 5% opacity.

Page 4 of 4, Condition 5: The permit requires monitoring the pneumatic line pressure and the pressure differential across the baghouse during visible emissions tests. The baghouses will be cleaned by pulse jet, which is activated by a pressure differential set point. However, the pressure gauge is optional and U.S. Sugar was not planning on purchasing this. Are these gauges necessary? The pneumatic line pressure for loading the silos by truck would be dependent on the trucks and for unloading the railcar to the receiver would depend on the railcars. It is not clear at this time if proper gauges would be installed or available to take these measurements. Is this monitoring requirement necessary?

Response: The pressure differential gauge is necessary to ensure proper operation of the equipment. It is common industry practice to monitor line pressure when pneumatically unloading lime or similar products. High line pressures can overload a system or otherwise cause excess fugitive emissions. No changes were made to the permit.

CONCLUSION

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

NOTICE OF FINAL PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-034-AC
New Lime Loading/Unloading System

Authorized Representative:
Mr. William A. Raiola
Vice President of Sugar Processing Operations

Enclosed is the Final Permit, which authorizes installation of two new lime silos, truck and railcar pneumatic unloading and conveying equipment, three associated baghouse control systems, and a lime slaker system (as necessary). The new equipment will be installed at the existing Clewiston Mill and Refinery, which is located in Hendry County at 111 Ponce DeLeon Avenue in Clewiston, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/20/06 to the persons listed:

Mr. William A. Raiola, U.S. Sugar*
Mr. Don Griffin, U.S. Sugar
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office

Clerk Stamp

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

Mary L. Harvey (Clerk) 1/20/06 (Date)

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE:

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Authorized Representative:
Mr. William A. Raiola
Vice President of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. 0510003-034-AC
Facility ID No. 0510003
SIC Nos. 2061, 2062
Permit Expires: February 1, 2009

PROJECT AND LOCATION

This permit authorizes installation of two new lime silos, truck and railcar pneumatic unloading and conveying equipment, three associated baghouse control systems, and a lime slaker system (as necessary). The new equipment will be installed at the existing Clewiston Mill and Refinery, which is located in Hendry County at 111 Ponce DeLeon Avenue in Clewiston, Florida. The UTM coordinates are Zone 17, 506.1 km East, and 2956.9 km North.

STATEMENT OF BASIS

This air pollution construction 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 install the proposed equipment 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

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

Michael G. Cooke, Director — 1/11/06 (Date)
Division of Air Resource Management

FACILITY AND PROJECT DESCRIPTION

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

A combination of lime and flocculants are used to clarify raw sugarcane juice, which is then evaporated, crystallized, and centrifuged to form raw sugar. Some of the raw sugar is sold and some of it is processed at the on-site refinery into white sugar. The applicant proposes new equipment to unload and store lime for use in the process (new Emissions Unit 031). Lime will be delivered by railcar and/or truck and unloaded into two new storage silos. The total throughput of lime is expected to be approximately 5000 tons per year. Lime will be unloaded from the silos via bottom drop into a lime slaker. Water will be mixed with the lime and pumped to a lime slurry storage tank and agitator for use in the process.

Lime will be unloaded pneumatically from trucks to the silos by a blower system at a rate of approximately 33 tons per hour. A 25 ton truck will be unloaded in about 45 minutes. Lime will be unloaded from railcars by a separate vacuum-type system, which includes a collection bin, rotary airlocks, and transporter blower to pneumatically transport lime to the silos at a rate of approximately 10,000 pounds per hour. It will take about 18 hours to unload 180,000 pounds of lime from a railcar.

Each silo and the collection bin will be controlled by a baghouse. The silos will be controlled with a bin vent filter to remove particulate matter during silo loading and unloading. Emissions from the collection bin will be controlled by a filter receiver to remove particulate matter during railcar unloading. Each baghouse will be designed for a flow rate of less than 500 acfm and an outlet grain loading of 0.02 grains per dscf. It is estimated that the maximum particulate matter emissions from each baghouse will be 0.08 pounds per hour and 0.35 tons per year. The project will result in a potential increase in particulate matter emissions of 1.05 tons per year.

REGULATORY CLASSIFICATION

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

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

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

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

NSPS: The facility operates units subject to a New Source Performance Standard in 40 CFR 60.

NESHAP: The facility operates units subject to a National Emissions Standard for Hazardous Air Pollutants in 40 CFR 63.

RELEVANT DOCUMENTS

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

1. Permitting Authority: The permitting Authority for this project is the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resources Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3381.
3. Appendices: The following Appendices are attached as part of this permit: Appendix A (Citation Format); Appendix B (General Conditions); and Appendix C (Common State Regulatory Requirements).
4. 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.). 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.]
5. 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.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Baghouses - Lime Silo Loading/Unloading (EU-031)

This section of the permit addresses the following emissions unit.

Emissions Unit No. 031
This emissions unit regulates the loading and unloading of the two new lime silos by truck and railcar. Baghouse control systems will be installed on each lime silo (Emissions Points LS-1 and LS-2) and on the collection bin (Emission Point CB-1) associated with the railcar unloading system. The exhaust from each baghouse vent is at ambient conditions and is located approximately 65 feet above ground level.

EQUIPMENT

1. Equipment: This permit authorizes installation of two new lime silos, truck and railcar pneumatic unloading and conveying equipment, three associated baghouse control systems, and a lime slaker system (as necessary). Each baghouse control system shall be designed and maintained for a flow rate of approximately 500 acfm and an outlet grain loading of 0.02 grains per dscf. [Rule 62-4.070(3), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Restricted Operation: The hours of operation of are not limited (8760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

3. Opacity Standards: Emissions from each baghouse vent shall not exceed 5% opacity. The permittee shall take reasonable precautions to minimize fugitive particulate matter emissions from other activities related to silo loading and unloading. Emissions from these other activities (without baghouse controls) related to silo loading and unloading operations shall not exceed 20% opacity. [Rules 62-4.070(3) and 62-296.320(4)(b), F.A.C.]

EMISSIONS PERFORMANCE TESTING

4. Compliance Tests: In accordance with EPA Method 9, each baghouse vent shall be tested to demonstrate compliance with the emissions standards specified. Initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. Subsequently, each baghouse vent shall be tested annually to demonstrate compliance with the opacity standards during each federal fiscal year (October 1^{st} to September 30^{th}). The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Separate tests shall be conducted while unloading lime from a truck and unloading lime from a railcar unless these systems can be used simultaneously. Tests shall be conducted at a lime unloading rate representative of the typical operation used throughout the year. [Rule 62-297.310(7)(a), F.A.C.]

RECORDS AND REPORTS

5. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix C of Section 4 of this permit. For each test run, the report shall also indicate the lime unloading rate, pneumatic line pressure, and pressure differential across the baghouse. [Rule 62-297.310(8), F.A.C.]

CONTENTS

Appendix A. Citation Formats
Appendix B. General Conditions
Appendix C. Common State Regulatory Requirements

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 CRF 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 (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not Applicable).

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 STATE REGULATORY REQUIREMENTS

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

EMISSIONS AND CONTROLS

1. 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.]
2. 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.]
3. 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.]
4. 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.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee 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.]
6. 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.]
7. 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.]
8. 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. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. 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.]
11. 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.]

12. 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.]

13. 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.]

14. 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.]

15. 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.

16. 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.]

17. 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.]

18. 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

19. <u>Records Retention</u>: 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. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

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

TABLE D-1
PHYSICAL, PERFORMANCE, AND EMISSIONS DATA
FOR THE MECHANICAL DRAFT COOLING TOWER AT U.S. SUGAR CLEWISTON

Parameter	One Cooling Tower
Physical Data	
Number of Cells	3
Deck Dimensions, ft	
Length	72
Width	66
Height	36
Stack Dimensions	
Height, ft	50
Stack Top Effective Inner Diameter, per cell, ft	22
Effective Diameter, all cells, ft	66
Performance Data	
Discharge Velocity, ft/min	2,303
Circulating Water Flow Rate (CWFR), gal/min	20,000
Design hot water temperature, °F	124
Design cold water temperature, °F	90
Heat Rejected, million Btu/hr	340
Design Air Flow Rate per cell, acfm	875,123
Liquid/ Gas (Air Flow) (L/G) Ratio	0.957
Hours of operation	8,760
Emission Data	
Drift Rate[a] (DR), percent	0.005
Total Dissolved Solids (TDS) Concentration[b], ppm	1,500
Solution Drift[c] (SD), lb/hr	500
PM Drift[d], lb/hr	0.75
tons/year	3.3
PM10 Drift[e]	
PM10 Emissions, lb/hr	0.54
tons/year	2.4

[a] Drift rate is the percent of circulating water.

[b] Calculated from a specific conductivity of 2,000 umho/cm.

[c] Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr).

[d] PM calculated based on total dissolved solids and solution drift (TDS x SD).

[e]. PM10 based on Cooling Tower PM10 emissions study: PM10 = 72.59% of PM.

Source: U.S. Sugar, 2006; Golder, 2006.