STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Murray T. Brinson, Vice President
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Air Permit No. 0510003-009-AC (PSD-FL-272)
Boiler No. 4 and Refinery Expansion
Palm Beach County, Florida

Enclosed is Final Permit No. 0510003-009-AC (PSD-FL-272). This permit authorizes U.S. Sugar Corporation to expand the operation of Boiler No. 4 and emissions units associated with refinery operation. As noted in the Final Determination (attached), minor changes to the draft permit were made by the Department, mostly at the requests of the applicant and EPA Region 4. 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 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Date: 11/19/99

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11-22-99 to the person(s) listed:

Mr. Murray T. Brinson, USSC*
Mr. Dave Buff, Golder Associates
Mr. Phil Barbaccia, South District Office – DEP
Ms. Katy Forney, EPA Region 4
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

11-22-99
(Clerk) (Date)

The Department distributed an Intent to Issue Permit package on October 4, 1999 to allowing the applicant to expand operations of Boiler No. 4 and several refinery emissions units for the Clewiston Sugar Mill located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on October 13, 1999. During the 30-day comment period, the Department received comments from the applicant and EPA Region 4. A summary of these comments and the Departments response and any resulting revisions follows.

REVISIONS INITIATED By THE DEPARTMENT

Section III. EU 009 – Boiler No. 4

S.C. 6. The Department inadvertently omitted the maximum annual oil-firing rate of 500,000 gallons per year, as requested by the applicant and specified in previous PSD permits. This limit will be added to this condition.

S.C. 23. This condition was revised to require reporting of the "minimum data availability" as previously discussed for Specific Condition No. 6., Section II, as a result of the applicant's request.

Section III. EU017 – GCRF

S.C. 9. This condition was changed to clarify the following: initial tests are required for PM, VOC, and visible emissions; an annual test is required for visible emissions; after initial compliance is demonstrated for the PM and VOC, compliance with these standards may be assumed as long as the emissions unit is in compliance with the visible emissions standard and monitoring requirements for the afterburner and wet scrubber; tests for PM and VOC are required during the year prior to renewal.

COMMENTS/REQUESTS FROM THE APPLICANT (11/02/99 and 11/18/99)

Entire Permit. Request: Applicant requests changing the word "operator" or "operators" to "permittee" throughout the permit in order to allow someone other than the boiler operator to actually perform the required task. Persons other than the boiler operator may take certain readings, etc. **Response**: The requested change was made throughout the permit, except for conditions specific to operation of the boiler.

Section II. Administrative Permitting Requirements

S.C. 5. Request: Applicant requests deletion of the first sentence, "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." **Response**: The Department issues a permit based on reasonable assurance provided by the applicant that the emissions units are capable of complying with the applicable regulations. Reasonable assurance may consist of individual items in the application or additional information provided to supplement the application. In other words, the application is the mechanism used to relay "reasonable assurance" to the Department. These items may not directly result in specific permit conditions, but at the very least provide the basis for issuing the permit and making control equipment determinations. The Department does not believe this condition suggests that the application is an enforceable document, but merely requires the applicant to accurately state the capacity and specifications for all emissions units. The specific condition was retained as drafted.

S.C. 10. Request: Applicant requests a new specific condition that establishes a minimum data availability requirement of 75%. Such a requirement would accommodate malfunctions and other technical issues (*e.g.*, replacement of chart paper) related to the use of monitoring equipment and automated data recording devices.

Response: Most of the record keeping requirements specified in this permit are manual. Several could be automated with uncomplicated and inexpensive devices. The new condition was added, but required a minimum data availability of 90% on a on a monthly basis. New requirements to report the data availability were also added to the Monthly Operations Summary (Specific Condition No. 23).

Section III. EU 009 – Boiler No. 4

EU Description. Request: Applicant requests a footnote to the emissions unit description, clarifying that the description is provided as information and not enforceable conditions. **Response**: The Department does not consider the information provided in the emissions unit description to be "enforceable" as a permit condition. However, the description does contain information that may also be included as a limit in a permit condition or that provided the basis for such a limit. The following footnote was added: "The above description is based on information contained in the application and is for informational purposes only."

S.C. 6. Request: Applicant requests that the fuel oil limit be in mmBTU/hr (as in the previous permit), which is approximately equivalent to 1,500 gal/hr (depending on heating value of the fuel oil). **Response**: The fuel oil limit is important because air dispersion modeling was based on this maximum level. The permit requires installation and operation of a fuel oil flow meter to demonstrate compliance. The applicant does not measure heat input from oil directly, but does measure oil flow rate. The slightly more restrictive consumption limit was retained with the intent of a clear demonstration of compliance. **Request**: Applicant also requests that Boiler No. 4 be allowed to fire any remaining oil in the common fuel tank, which may contain more than 0.7% sulfur by weight for a period of time. **Response**: During the application process, the applicant made it clear that if BACT was determined to be the *actual firing* of fuel oil containing 0.7% sulfur by weight in Boiler No. 4, then a separate fuel storage tank would be installed as opposed to paying higher fuel costs for Boilers 1 through 3. Also, additional information provided for during the approval of the ISC Prime model seems to indicate that the applicant intends to retain fuel oil containing up to 2.5% sulfur by weight and has no intention of switching to fuel oil containing 0.7% sulfur by weight. Therefore, the second paragraph of this condition was revised to read:

"To comply with the fuel sulfur limit, the permittee shall install a new, dedicated storage tank for Boiler No. 4 within 120 days of issuance of this permit. Prior to completion of construction of the new tank, Boiler No. 4 may fire fuel oil from the common tank shared by Boiler Nos. 1 through 4, which may contain a higher sulfur content. The sulfur content of the fuel shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. Compliance with the fuel oil consumption limits shall be determined by the monitoring and record keeping requirements of this permit. [Applicant Request, Rule 62-210.200 (Definitions - PTE) and Rule 62-212.400 (BACT), F.A.C.]"

S.C. 7. Request: Applicant claims the ISCST3 modeling analysis demonstrated that, if the stacks are ultimately raised to 213 feet to meet the PM and CO ambient standards, Boiler Nos. 1, 2 and 3 would be then able to burn up to 1.5% sulfur fuel oil and comply with the SO_2 ambient standards and increments. Applicant requests that this condition be revised to reflect this situation. **Response**: The Department's intent to issue the Draft Permit was based on lowering the sulfur content for the Boilers 1 through 3 sharing the common tank with *fuel oil determined to be BACT for Boiler No. 4*. The Draft Permit does allow for modification of the fuel oil sulfur content for Boilers 1 through 3 as a result of the final approved air quality analysis that is based on ISC Prime. However, at this time, the input parameters and results of the analysis are not final. The requested revisions were not made. **Request:** Applicant stated that FDEP approves the modeling, while EPA must approve the use of the ISC-Prime model. **Response**: This is correct. EPA Region 4 has already approved the non-guideline model (ISC Prime) for use with this project. With corroboration from EPA Region 4, the Department will approve or reject the air quality analysis for this project that is based on the ISC Prime model.

This condition was clarified. **Request:** Applicant requested insertion of the word "currently" to clarify sharing of the common tank by Boilers 1 through 4. **Response**: The text was revised.

S.C. 8. Request: Applicant requests revising the water flow rate parameter to a 3-hour block average, consistent with the time required to conduct compliance testing. The applicant maintains that it is simpler to require a reading every four hours, instead of complicating it with the beginning and ending of a shift. A continuous recorder could be installed for this purpose. **Response**: To simplify record keeping requirements, the minimum scrubber flow rate was revised from 250 gpm based on a 6-minute average to 375 gpm based on a 3-hour average and required readings for all parameters at startup and every three hours. The higher flow rate was considered more appropriate for the longer averaging time and remains consistent with the current operation as stated in the application. The option of installing a continuous recorder was included.

S.C. 9. Request: Applicant requests ninety (90) days for submitting the results of the CO/O_2 testing program. It typically takes 15 to 30 days to receive a report from the testing firm, depending on the workload, then 1 to 2 weeks for our review of the draft test report. Analyzing the report for a relationship between CO and O_2 will then require some time, as well as preparing a report of the analysis. Based on the time frames in the draft permit, any additional good combustion practices would not be implemented until the 2000-2001 crop season. The additional 60 days requested would not alter this ultimate schedule, it would merely allow additional time during the summer off-season in which to analyze the data. **Response**: The condition was revised to allow sixty (60) days to submit the results of the testing program.

S.C. 13. Request: Applicant requests a 30% opacity standard as allowed by Rule 62-296.410(2)(b)1., F.A.C., not the 20% opacity cited in this condition. **Response**: As noted by the applicant in the application, the 20% opacity standard was established as BACT during a previous permit modification (PSD-FL-217). The condition was not revised.

S.C. 14 Request: To satisfy EPA's comments, the applicant requests a lower SO2 limit of 0.06 lb/mmBTU. **Response**: Condition was revised.

S.C. 16. Request: Applicant requests additional text to allow sample dilution as approved in an industry-wide ASP for sugar mill boilers. **Response**: The condition was revised.

S.C. 17. Request: Applicant requests that 120 days be allowed to perform the initial compliance tests, to be consistent with the 120 days allowed under S.C. 9 for installing the CO/O_2 process monitors. This will allow the CO and O2 process monitors to be operational during the compliance testing, which will provide additional parametric data. **Response**: Initial testing must be conducted to demonstrate compliance with the BACT standards. The permittee may perform the parametric monitoring during the compliance testing. The "extra" 30 days was provided to allow for the additional CO testing to establish CO and O_2 flue gas parameters representative of good combustion practices. The condition was not revised.

S.C 18. Request: Due to the very low SO_2 emissions from bagasse, and the previous SO_2 testing on Boiler No. 4 (provided in the application), the applicant requests that the SO_2 test frequency be reduced to once very five years. The applicant also requested to lower the SO_2 limit to 0.06 lb/mmBTU to satisfy EPA's comments about its adequacy. **Response**: In consideration for the lower sulfur limit, the Department revised this condition to read: "If the initial SO_2 performance test indicates SO_2 emissions are greater than 0.03 lb/mmBTU of heat input, the permittee shall conduct an annual performance test to demonstrate compliance with the SO_2 emissions standard."

S.C. 21. Request: Applicant requests additional text to clarify scrubber (spray nozzle) flow rates and that the heat input is calculated. **Response**: Minor changes were made to this condition.

S.C. 22. Request: Applicant suggests adding "... and maintain this information in a readily accessible manner and be kept on site for at least five years ..." to, and deleting "... in a daily log." from the record keeping requirements specified for the Daily Log. **Response**: Additional text was not added. "Daily Operation Log" was changed to "Daily Operational Records".

- **a.** **Request:** Add text " ... as covered by Common Condition No. 6." to the requirement to record startup, shutdown and malfunction. **Response**: This text is unnecessary and the condition was not revised.
- **b.** No changes requested.
- **c.** **Request:** Delete requirement to record CO and O_2 data at the beginning of the shift and at the end of the shift and leave requirement to record data at least once every hour. **Response**: This condition was changed to require recording data once startup was complete and normal operation was established and at least once per hour during operation.
- **d.** **Request:** Delete requirement to record wet scrubber data at the beginning of the shift and at the end of the shift and leave requirement to record data at least once every 4 hours. **Response**: This condition was changed to require recording data once startup was complete and normal operation was established and at least once every three hours, consistent with the previous revision for Specific Condition No. 8.
- **e.** **Request:** Change rolling average to block average for oil flow rates. **Response**: The condition was revised.
- **f.** **Request:** Add text "... for Boiler No. 4 ..." to oil delivery requirements. **Response**: Depending on the option selected by the permittee, Boiler No. 4 may fire fuel from a common tank. Therefore, this condition would apply to all fuel oil deliveries to the common tank. The condition was not revised.
- **g.** **Request:** Delete text "... in the Daily Operations Log." From the requirement to record calibrations and repairs. **Response**: The Department views the Daily Operations Log as the combination of data recorded by the permittee to comply with the conditions of the permit. In addition, the information should be used to adjust operations to maintain compliance with operating, control, emission, and capacity requirements. "Daily Operation Log" was changed to "Daily Operational Records".
- **h.** **Request:** Change "... next workday." to "... 3rd following workday ..." to allow for weekends and holidays. **Response**: These parameters are key operating and control parameters. The operating supervisor is responsible for monitoring and reviewing data as well as adjusting operations to comply with the requirements of the permit. Summarizing four key parameters should not be burdensome. The condition was not changed. **Request:** Add text "... as determined from Condition 22.e." to oil firing rate data. **Response**: This condition was revised to read "... as determined by data collected from the oil flow meter ..." **Request:** Add a list of items for which to take corrective actions to regain proper operation. **Response**: This condition was revised by adding the text, "For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any."

S.C. 23. Request: Applicant requests that certain items be deleted from the Monthly Operations Summary because there is no associated permit limitation. Also requests specification of the parameters that are required to be reported for operation outside specified limits. **Response**: This condition was changed to remove reporting for the steam production and heat input rates based on monthly 24-hour averages, as unnecessary. The 12-month fuel oil rate was retained because there is a limit on the 12-month rolling total for fuel consumption (see previous revision of Specific Condition No. 6.). This condition was also revised to read, "If the data indicates operation outside of the specified permit limits for steam production, heat input, wet bagasse consumption, or the oil firing rates, then the permittee shall submit a written notification and summary to the Compliance Authorities within ten (10) calendar days of recording the data."

Section III. EU024. Fuel Tank

EU Description. Request: Applicant requests specifying a larger fuel tank (up to 250,000 gallons) and deletion of the fuel oil sulfur content from the description. **Response**: The fuel tank size was increased as requested, but the text specifying the sulfur content was retained. In addition, the a new condition was added to require that the tank be clearly marked with a sign stating, "This is the fuel oil storage tank for Boiler No. 4. Only fuel oil containing 0.7% by weight or less may be added to and stored in this tank."

Section III. EU017 - GCRF

EU Description. Request: Applicant requests a qualifying footnote be placed on the emissions unit description, so it is clear that these are not permit conditions. **Response**: The Department will add the following footnote: "The above description is based on information contained in the application and is for informational purposes only."

SC.4. Request: Applicant requests the following: add the text "designed" is added to describe the 92% VOC destruction efficiency; remove the requirement to continuously record afterburner temperature; add text to inform that operation below the minimum afterburner temperature is not necessarily a violation, but continued operation outside the specified range could constitute circumvention of the control equipment. **Response**: The condition was changed to "... designed to destroy at least 92% of the VOC emissions ...". Unlike the wet scrubber parameters used as a surrogate for effective particulate control, the afterburner temperature directly correlates to PM and VOC emissions. The Department retained the requirement to continuously monitor for compliance with the minimum afterburner temperature. However, the condition was revised to read, "Excluding initial startup, shutdown, and malfunction, the afterburner temperature shall be maintained at 1200°F or higher except for up to 6 total minutes each hour during which the temperature shall not fall below 1000°F."

S.C. 5. Request: Applicant requests revising the required pressure drops for the venturi to 12 - 30 inches of water and for the wet tray scrubber to 3 - 8 inches of water. These values are stated as being consistent with the actual design. Corresponding changes were requested for the Emissions Unit Description. **Response**: The revisions were made. **Request**: Applicant requests text to clarify that the scrubber is only needed during regeneration of carbon, similar to that included for the afterburner. Also requests addition of text stating that operation outside of the specified pressure drop ranges is not necessarily a violation, but continued operation outside the specified range could constitute circumvention of the control equipment. **Response**: The condition was revised.

S.C. 6. Request: Applicant requests a general VE limit of 20% opacity for the granular carbon regenerative furnace. Also requests additional text that the permittee may accept 5% opacity in lieu of an annual stack test. **Response**: Although the proposed 20% opacity is unreasonable, the Department reconsidered the 5% opacity limit based on control by the wet scrubber. This condition was revised to, "In addition, visible emissions shall not exceed 10% opacity (excluding water vapor) as determined by EPA Method 9."

S.C. 9. Request: Applicant requests that the permit allow revision of the emissions standards if compliance testing shows higher emissions while operating within the design specifications for the control equipment because the limits are based on vendor estimates, not guarantees. **Response**: When originally permitted, this information was submitted as the basis to escape PSD review. In this PSD application, the information was again presented as the best available information for this equipment, and was used as the basis for selecting this equipment as BACT. Failure of the compliance test should result in improved control methods, not emissions limits. The condition was not changed.

S.C. 11. Request: Applicant requests that "wet" be added to describe the scrubber and to change "production capacity" to "operating capacity". **Response**: The text "wet" was added. Production capacity was retained as the proper term.

EU - Miscellaneous Particulate Sources

EU Description. Request: Applicant requests changing the term "dust collector" to "baghouse". **Response**: The description was changed.

S.C. 2. Request: Applicant requests adding the phrase "of refined sugar" to clarify the production capacities. **Response**: The condition was revised.

Appendix GC

G.3. Request: Applicant requests changing "and vested rights" to "any vested rights". **Response**: The condition was revised consistent with the rule.

Appendix GCP

CO and VOC Controls. Item 3. Request: Applicant requests removal of the requirement to control the bagasse moisture content below 55% by weight because O_2 and CO process monitors are being installed, which will aid in achieving good combustion practices. **Response**: The bagasse moisture content is generally a function of weather. This requirement was deleted.

Cold Startup. Request: The applicant requests deletion of the statement at the end of the cold startup. **Response**: Excluding visible emissions, compliance with the emissions standards is unknown for all pollutants except during an emissions test. Therefore, this statement was removed.

COMMENTS FROM EPA REGION 4 (11/12/99)

BACT Determination

1. **EPA Comment**: Specific Conditions 2 and 3 for Boiler No. 4 do not effectively limit annual hours of operation or fuel oil consumption. **Response**: The annual fuel consumption limit was inadvertently omitted. Specific Condition No. 6 for Boiler No. 4 was revised to limit fuel oil consumption to 500,000 gallons during any consecutive 12 months.
2. **EPA Comment**: Section III, Specific Condition No. 6 allows up to 2 hours of excess emissions for the granular carbon regenerative furnace. It is EPA's policy not to grant automatic exemptions for excess emissions. **Response**: This condition is actually a Common Condition applicable to all emissions units and is verbatim from Florida's Rule 62-210.700, F.A.C.
3. **EPA Comment**: The SO_2 limit of 0.10 lb/mmBTU is believed to exceed a reasonable margin for compliance. EPA requests that the Department reconsider this standard. **Response**: The previous PSD permit established an SO_2 limit of 0.166 lb/mmBTU of heat input when firing bagasse. The proposed standard of 0.10 lb/mmBTU represents a 40% reduction in allowable emissions. To satisfy EPA's concerns, the applicant requested a lower limit of 0.06 lb/mmBTU. In consideration of the lower standard, the applicant requested emissions performance testing every five years if the initial testing showed levels

below 0.03 lb/mmBTU. The Department is reluctant to reduce the standard further due to limited data for this specific source. The revised standard would result in SO2 emissions of approximately 84 tons per year and less than 42 tons per year is testing shows emissions of half the standard. The limit and testing requirement was revised.

Air Quality Analysis

1. and 2. **EPA Comment**: EPA states that the air quality analysis based on ISCST3 is not appropriate as the basis for issuance of the permit because EPA has already approved the use of ISC Prime model for this project and is now reviewing the air quality analysis based in ISC Prime. EPA requested concurrence before the final permit is issued. **Response**: The applicant has provided two air quality analyses with the request to expand operation of Boiler No. 4 and the refinery operations. The first analysis was based on the non-guideline model, ISC Prime, which required EPA approval of the model prior to a review of the air quality analysis that is based on ISC Prime. The applicant was confident that once the ISC Prime model was approved, the results of the air quality analysis would demonstrate that no changes to Boilers 1 though 3 would be necessary. However, it became apparent that EPA may require several months to review and approve the non-guideline model. It was important to the applicant to obtain the modification prior to the upcoming sugarcane crop season, so an "interim" analysis based on ISCST3 was submitted to the Department. This analysis included raising stack heights and lowering fuel sulfur contents for Boilers 1 through 4 and resulted in no significant modeled impacts. The Draft Permit was conditioned such that if air quality analysis based on the ISC Prime model was not approved prior to final issuance, the following requirements must be met: (1) only oil with a sulfur content of 0.7% by weight be purchased and stored in the common tank for Boilers 1 through 4; a final plan for increasing the stack heights within 180 days of permit issuance; (3) construction to increase the stack heights would be complete within on year after permit issuance. The Draft Permit also included language indicating that these conditions would no longer apply contingent on EPA's approval of the ISC Prime model and the Department's approval of the air quality analysis within 180 days of final permit issuance. Finally, the Draft Permit stated that it may be necessary to revise several conditions of the permit based on the final approved modeling analysis. The Department considered this alternative because the problems with the modeled impacts for CO, PM, and SO2, are existing concerns whether or not the modification was granted. The problems are mostly the result of a new building causing potential downwash problems. Issuing the permit would impose more stringent BACT limits, require additional monitoring and testing, immediately require the purchase and use of low sulfur fuel oil for Boilers 1 through 4, and authorize a stack height increase to minimize the ambient impacts. The Department intended to issue the Draft Permit on the basis of the "interim" air quality analysis because it was a step toward solving the problem.

   The Department participated in a teleconference with EPA Region 4 engineers and meteorologist to resolve any issues with the final permit. Based on this conversation, the Department believes that the revised Specific Conditions Nos. 6 and 7 for Boiler No. 4 satisfy EPA's concerns. The primary revision is for the applicant to submit an application to modify the permit based on the final outcome of any revised air quality analysis.

CONCLUSION

The Department does not consider any of these revisions to be substantial and, in fact, some changes reduce emissions. The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

PERMITTEE

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

Permit No.	051-0003-009-AC
PSD No.	PSD-FL-272
Project:	Boiler No 4 and Refinery Expansion
SIC No.	2061, 2062
Expires:	November 22, 2000

Authorized Representative:
Murray T. Brinson, Vice President

PROJECT AND LOCATION

This permit authorizes the United States Sugar Corporation to modify operations at its existing sugar mill and refinery. Specifically, the permit allows increased operation of Boiler No. 4 and the existing refinery operation, the installation of three new sugar conditioning silos, and the installation of additional powdered sugar/starch silos.

This facility is located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The UTM coordinates are Zone 17, 506.1 km E, and 2956.9 km N.

STATEMENT OF BASIS

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and the Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297. The above named permittee is authorized to construct and modify the emissions units 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 of Environmental Protection (Department).

APPENDICES

The attached appendices are a part of this permit:

Appendix A	Terminology
Appendix BD	BACT Determination
Appendix GC	General Permit Conditions
Appendix GCP	Good Combustion Practices Plan

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 11/19/99

FACILITY DESCRIPTION

This facility consists of an existing sugar mill and refinery. Sugarcane is harvested from nearby fields and transported to the mill by train or truck. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze the juice from the cane. The cane 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 in the mill are the bagasse/oil-fired Boilers Nos. 1 through 6 with wet scrubbers for particulate matter control and the bagasse/oil-fired Boiler No. 7 with an electrostatic precipitator to control particulate matter. Air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, conditioning silos with duct collectors, vacuum systems, sugar/starch bins, conveyors, and a packaging system.

PROJECT DETAILS

This permitting action modifies the following existing emissions units and adds three new sugar conditioning silos and powdered sugar/starch bins.

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
009	Bagasse Boiler No.4 with wet scrubber (300,000 pounds of steam per hour)
015	VHP sugar dryer with baghouse
016	White sugar dryer with baghouse
017	Granular carbon regenerative furnace with afterburner and wet scrubber
018	Three vacuum pickup systems, each controlled with a baghouse
019	Six conditioning silos, each controlled with a baghouse
020	Screening/distribution and sugar/starch bins each controlled with baghouses
021	Alcohol emissions
022	Packaging dust collector
023	Two propane-fired sock dryers
024	NSPS fuel storage tank for Boiler No. 4

REGULATORY CLASSIFICATION

HAPs: This facility is not believed to be a major source of hazardous air pollutants (Title III).

Acid Rain: This facility is not subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution because potential emissions of at least one regulated criteria air pollutant, such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceeds 100 tons per year.

PSD Major Source: This facility is a PSD major source of air pollution because potential emissions are greater than 250 tons per year for at least one criteria pollutant, in accordance with Rule 62-212.400, Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, each modification to this facility resulting in emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2 also requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC are significant and subject to the BACT standards specified in this permit.

NSPS Sources: This project includes an emission unit subject to regulation under the New Source Performance Standards, 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit and are on file with the Department. They are specifically related to this permitting action.

- Permit application received June 25, 1999 and associated correspondence to make complete.
- EPA's comments dated September 24, 1999.
- NPS's comments dated August 11 and 26, 1999.
- Department's Technical Evaluation and Preliminary Determination issued with the Draft Permit.
- Department's Intent to Issue dated October 4, 1999.
- Comments from the applicant received on November 2, 1999 and November 18, 1999.
- Comments received from EPA Region 4 received November 12, 1999.

1. Permitting Authorities: All documents related to applications for permits to construct or modify emissions units requiring a PSD applicability review and determination of BACT shall be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, phone number 850/488-0114. Minor modifications and Title V operating permit applications shall be submitted to the South District Office, Florida Department of Environmental Protection at 2295 Victoria Avenue, Suite 364 in Fort Myers, Florida 33902-2549 and phone number (941) 332-6975.

2. Compliance Authorities: All documents related to reports, tests, and notifications shall be submitted to the South District Office, Florida Department of Environmental Protection at 2295 Victoria Avenue, Suite 364 in Fort Myers, Florida 33902-2549 and phone number (941) 332-6975.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations referenced in this permit.

4. General Conditions: The permittee is subject to and shall operate under the attached General Conditions listed in *Appendix GC* of this permit. General conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. 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, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-210, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.). 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.]

6. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., 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.]

7. Expiration: For good cause, the permittee may request that this construction permit be extended. Such a request shall be submitted at least 60 days before the expiration of the permit to the Department's Bureau of Air Regulation. [Rules 62-210.300(1), 62-4.080, and 62-4.210, F.A.C.]

8. 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 must be obtained prior to the beginning of construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. Operation Permit Required: This permit authorizes modification 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 and receive a Title V operation permit prior to expiration of this permit. 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 and Compliance Authorities. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS UNIT 009. BOILER NO. 4

This portion of the permit addresses the following emissions unit.

EU ID No.	EMISSIONS UNIT DESCRIPTION
009	Boiler No. 4: This is a traveling grate boiler manufactured by Foster Wheeler capable of producing a maximum of 300,000 pounds of steam per hour at 750° F and 600 psig. The unit has two burners with two oil guns each and the following restricted maximum heat inputs: *Bagasse Firing*: 633 mmBTU per hour (This is equivalent to producing 300,000 pounds of steam per hour when firing 88 tons of wet bagasse per hour, assuming a heat content of 3600 BTU per pound of wet bagasse. Typically wet bagasse contains 50-55% moisture and less than 0.1% sulfur by weight.) *Bagasse With Maximum Oil Firing*: 530 mmBTU per hour (This is 225 mmBTU per hour from firing a maximum of 1500 gallons of oil per hour and 305 mmBTU per hour from firing 42.4 tons of wet bagasse to produce 300,000 pounds of steam per hour. Oil firing is more efficient at converting heat to steam.) Particulate matter emissions are controlled by a Type D, Size 200 Joy Turbulaire wet impingement scrubber. A nominal 250 to 500 gallons per minute of water is supplied to the spray nozzles at approximately 50 psi. The differential pressure drop across the wet scrubber is maintained between 8 and 11 inches of water column. Exhaust gases exit the wet scrubber at an average flow rate of 281,000 ACFM at 160° F. The stack is 150 feet high (GEP stack height is 225 feet high).

Note: The above description is based upon information provided in the application and is for informational purposes only.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Pursuant to Rule 62-212.400, F.A.C., this emissions unit is subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). In addition, this emissions unit is subject to Rule 62-296.410, F.A.C. which regulates visible emissions and particulate matter emissions from carbonaceous fuel fired equipment.

PERFORMANCE RESTRICTIONS

2. Hours of Operation: The hours of operation for this unit are not restricted (8,760 hours per year). [Rule 62-210.200, F.A.C., Definitions - PTE]

3. Permitted Capacity: Steam production, heat input, and bagasse firing shall not exceed the following limits.

Averaging Period	Steam Pressure [a]	Steam Temperature [a]	Steam Production (lb / hour)	Heat Input [b] (mmBTU / hour)	Wet Bagasse Firing [b] (tons / hour)
1-hour	600 psig	750° F	300,000	633	88
24-hour	600 psig	750° F	285,000	600	83

[a] Steam temperature and pressure are design parameters. Changes to these parameters resulting from boiler aging or modification shall be reported to the Department and may require a permit modification.

[b] Based on: 55% thermal efficiency of the boiler when firing bagasse; wet bagasse containing 55% moisture and a heat content of 3600 BTU/lb; and 1160 BTU per pound of steam at 600 psig and 750° F with standard feed water conditions of 900 psig and 250° F.

No more than 400,000 tons of bagasse shall be fired during any consecutive 12 months. In addition, the total heat input to this boiler shall not exceed 2,880,000 mmBTU during any consecutive 12 months. Compliance with the steam limits shall be determined by continuous monitoring of the steam temperature, steam pressure, and steam production rate. The heat input and bagasse consumption limits shall be calculated and recorded in accordance with the record keeping requirements of this permit. [Rule 62-210.200, F.A.C., Definitions - PTE]

4. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all boiler operators and supervisors shall be properly trained to operate and maintain the bagasse boiler and pollution control equipment in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include all "Good Combustion Practices" including those specified in *Appendix GCP* of this permit. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400 (BACT), F.A.C.]

5. Startup/Shutdown: During startup and shutdown of this boiler, the operators shall take all reasonable precautions to prevent and minimize the magnitude and duration of any excess emissions. *Appendix GCP* identifies the Good Combustion Practices for this boiler including the permittee's current startup and shutdown procedure. [Rule 62-210.700(1), F.A.C.]

6. Fuel Oil: The fuel oil fired in Boiler No. 4 shall be No. 6 fuel oil (or a superior grade) containing no more than 0.70% sulfur by weight. Boiler No. 4 shall not fire more than 1500 gallons in any hour or more than 500,000 gallons in any consecutive 12-month period. In addition, combined fuel oil consumption from Boiler Nos. 1, 2, 3, and 4 shall not exceed 16,200 gallons during any consecutive 3-hour block average or more than 88,000 gallons during any consecutive 24-hour block average. To comply with the fuel consumption limits, the permittee shall install, calibrate, operate, and maintain individual fuel oil flow meters with accumulators or continuous recording equipment for Boiler Nos. 1, 2, 3, and 4.

   To comply with the fuel sulfur limit, the permittee shall install a new, dedicated storage tank for Boiler No. 4 within 120 days of issuance of this permit. Prior to completion of construction of the new tank, Boiler No. 4 may fire fuel oil from the common tank shared by Boiler Nos. 1 through 4, which may contain a higher sulfur content. The sulfur content of the fuel shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. Compliance with the fuel oil consumption limits shall be determined by the monitoring and record keeping requirements of this permit. [Applicant Request, Rule 62-210.200 (Definitions - PTE) and Rule 62-212.400 (BACT), F.A.C.]

7. Interim Conditions: The Department is currently reviewing an air quality analysis for this facility that includes options of raising the stack heights for existing boilers, lowering the fuel sulfur content for existing boilers, or perhaps both. This is necessary to resolve potential adverse ambient impacts that may exist for this facility regardless of this modification. Until the issue of potential adverse ambient impacts is settled, the permittee shall comply with the following interim conditions.

   (a) The permittee shall immediately begin purchasing No. 6 fuel oil (or a superior grade) containing no more than 0.70% sulfur by weight as replacement oil for Boiler Nos. 1, 2, 3, and 4 to be stored in the common tank currently shared by these boilers. These boilers may fire oil from the common tank, which may contain oil with a sulfur content higher than 0.7% by weight due to the oil that is currently stored in the existing tank. As new deliveries of oil containing no more than 0.7% by weight are made, the sulfur content of this tank will gradually be reduced to 0.7% sulfur by weight or less. For each fuel oil delivery, the permittee shall record and retain the following: the date; the gallons of fuel delivered; and a fuel oil analysis, including the sulfur content (percent by weight), and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable.

(b) Within one year after issuance of this final permit, the permittee shall complete construction that increases the stack heights for Boiler Nos. 1, 2, 3, and 4 to 213 feet.

(c) Within 30 days of issuance of this permit, the permittee shall submit an application to the Department to modify this permit. The application shall include, but not be limited to, the following information:

1. A final air quality impact analysis based on ISC-PRIME consisting of only one fuel sulfur limit and stack height combination for each boiler at this facility. Following state and federal guidelines, the analysis must demonstrate that the project complies with the requirements for the ambient air quality standards and PSD increments.
2. Based on any assumed restrictions and input parameters used for the air quality impact modeling analysis, the permittee shall submit a final plan specifying any physical modifications or new limits that are necessary to ensure compliance with the ambient air quality standards and PSD increments.
3. A final summary of the maximum fuel consumption, fuel sulfur limits, heat input, steam production, stack height, volumetric flow rate, exhaust gas temperature, and emissions rates (pounds per hour and tons per year) for each facility boiler.
4. The application shall include Sections I and II of DEP Form No. 62-210.900(1) and only those pages in Section III that require revision as a result of the requested modification.
5. If the Department approves the requested modification, the permittee shall publish a Public Notice in a newspaper of general circulation with a 30-day comment period. The Department will provide the notice.

Note: The Department fully expects to issue a modified permit within the subsequent year. The modification will eliminate the requirements of these interim conditions, perhaps revise other existing conditions, and may require new additional conditions. [Applicant Request and Rule 62-4.070(3), F.A.C.]

CONTROL EQUIPMENT AND TECHNIQUES

8. Wet Scrubber: To control emissions of particulate matter, the permittee shall install, operate, and maintain a Type D, Size 200 Joy Turbulaire wet impingement scrubber. To ensure the annular throttling gap is being properly maintained, this system shall provide constant make-up water overflow to the scrubber as indicated by the weir box. The wet scrubber shall also be equipped with the following monitoring equipment.

   a. A **manometer** (or equivalent) shall be installed to measure the scrubber pressure drop in inches of water column. The pressure drop across the scrubber shall be maintained between 8 and 11 inches of water column.

   b. A **pressure gage** shall be installed to monitor the water supply pressure to the scrubber nozzles. This pressure shall be maintained between 40 and 55 psi.

   c. A **flow meter** shall be installed to measure the water flow rate to the scrubber spray nozzles. This flow rate shall be maintained above 375 gallons per minute, based on a 3-hour block average.

The monitoring equipment shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations. The permittee shall read and record each scrubber parameter once normal operations have been established after startup and at least once every 3 hours. Should any monitored parameter fall outside the specified operating range, the permittee shall investigate the cause and take corrective action to regain operation within the specified range. In addition, the permittee shall begin reading and recording all monitored parameters at 30-minute intervals until successive readings indicate operation within the specified range. The permittee may elect to install an automated recorder to satisfy the recording requirements. The permittee shall record any problems with operation of the wet scrubber and corrective actions taken in the Daily Operational Records required by this permit. Operation outside of the specified operating range for any monitored parameter is not a violation of this permit, in and of itself. However, continued operation outside of the specified operating range for any monitored parameter without corrective action may be considered circumvention of the air pollution control equipment. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400 (BACT), F.A.C.]

9. Good Combustion Practices: The boiler operators shall use the Good Combustion Practices (GCPs) defined in *Appendix GCP* to minimize emissions of CO, NOx, PM/PM_{10} and VOC from this boiler. As a critical part of the GCPs, the permittee shall install, calibrate, operate, and maintain process monitors to indicate the oxygen and carbon monoxide content of the exhaust flue gas in the boiler furnace within 120 days after issuance of this final permit. Readouts of these process monitors shall be provided in the boiler control room. It is noted that the monitored flue gas carbon monoxide content is for the purpose of determining efficient combustion and may not be representative of the actual CO emissions from the stack.

   In addition to the initial CO compliance testing required by this permit, the permittee shall conduct CO testing in accordance with EPA Method 10 for at least 12 additional 1-hour runs. This testing shall be conducted when the boiler is firing only bagasse and the boiler may be operated below 90% of permitted capacity. The permittee shall provide a 15-day advance notice of the proposed test schedule. During each run, the operators shall observe and record the CO and O_2 contents of the exhaust flue gas from the process monitors at 5-minute intervals. For each run, the operators shall monitor and record the hourly steam production rate, steam temperature, and steam pressure and calculate the bagasse consumption rate, and heat input. These additional tests shall be completed within 180 days after issuance of this final permit. A complete report summarizing the test methods, recorded parameters, boiler operation and adjustments, problems during testing, and final results shall be submitted to the Permitting and Compliance Authorities within 60 days of completing the required testing. The report shall discuss the relationship between flue gas oxygen content, flue gas carbon monoxide content, and combustion efficiency. The report shall also contain a recommendation by the permittee of an acceptable minimum flue gas oxygen content and a maximum carbon monoxide content that represents adherence to good combustion practices. Based on the test results and recommendation, the Department shall revise this condition and *Appendix GCP* to reflect additional good combustion practices and appropriate monitoring. The Department shall revise *Appendix GCP* as a minor permit amendment for this initial request. Subsequent changes to the good combustion practices shall be processed as minor permit modifications including a Public Notice. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400 (BACT), F.A.C.]

EMISSION LIMITING STANDARDS

10. CO Standard: Carbon monoxide emissions shall not exceed 6.5 pounds per mmBTU of total heat input based on a 3-hour test average as determined by EPA Method 10. Emissions performance testing for CO and NOx shall be conducted concurrently. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

11. NOx Standard: Nitrogen oxide emissions shall not exceed 0.20 pounds per mmBTU of heat input from bagasse firing based on a 3-hour test average as determined by EPA Method 7 or 7E. Emissions performance testing for CO and NOx shall be conducted concurrently. [Rule 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

12. PM/PM_{10}: Particulate matter emissions shall not exceed 0.15 pounds per mmBTU of heat input from bagasse firing nor 0.10 pounds per mmBTU of heat input from oil firing based on a 3-run test average as determined by EPA Method 5. Compliance when firing both fuels shall be determined by prorating the emissions standards based on the heat input from each fuel. [Applicant Request; Rules 62-296.410(2)(b)2. and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

13. Visible Emissions: Visible emissions from the boiler stack shall not exceed 20% opacity except for one, 2-minute period per hour of up to 40% opacity as determined by DEP Method 9. [Applicant Request; Rules 62-296.410(2)(b)1. and 62-212.400 (BACT), F.A.C.]

14. SO_2 Standard: Emissions of sulfur dioxide shall not exceed 0.06 pounds per mmBTU of heat input from bagasse firing based on a 3-run test average as determined by EPA Methods 6, 6C, or 8. This standard shall also serve as a surrogate for sulfuric acid mist (SAM) emissions, which are estimated to be 0.01 pounds per mmBTU of heat input from bagasse firing as determined by EPA Method 8. Emissions of SO_2 and SAM from fuel oil firing are limited by the sulfur content restrictions specified by this permit. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

15. VOC Standard: Emissions of regulated volatile organic compounds shall not exceed 0.50 pounds (as propane) per mmBTU of total heat input based on a 3-run test average as determined by EPA Method 18 and EPA Method 25A, modified to include a means of sample dilution. However, the sample shall not be diluted below the minimum detection limit for the flame ionization detector. Total VOC emissions shall be determined by EPA Method 25A and reported in terms of pounds per mmBTU as propane. EPA Method 18 shall be used to determine emissions of methane and reported in terms of pounds per mmBTU as propane. Emissions of regulated VOC shall be defined as the difference between the total VOC emissions and methane emissions reported in terms of pounds per mmBTU as propane. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A; and ASP No. 96-H-01]

PERFORMANCE TESTING REQUIREMENTS

16. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

    a. **EPA Method 5**, "Determination of Particulate Emissions from Stationary Sources".

    b. **EPA Method 6 or 6C**, "Determination of Sulfur Dioxide Emissions from Stationary Sources".

    c. **EPA Method 7 or 7E**, "Determination of Nitrogen Oxide Emissions from Stationary Sources".

    d. **EPA Method 8**, "Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources".

    e. **DEP Method 9**, "Visual Determination of the Opacity of Emissions from Stationary Sources".

    f. **EPA Method 10**, "Determination of Carbon Monoxide Emissions from Stationary Sources". All CO tests shall be conducted concurrently with NOx emissions tests.

g. **EPA Methods 18 and 25A**, "Determination of Volatile Organic Concentrations". This method may be modified to include a means of sample dilution. However, the sample shall not be diluted below the minimum detection limit for the flame ionization detector.

h. **ASME Boiler Efficiency Short Form Method**, "Boiler Thermal Efficiency Test Method". (This test shall demonstrate, in part, adherence to the maintenance provisions of the Good Combustion Practices Plan.)

During each SO_2 performance tests, the permittee shall sample and analyze the bagasse fuel for sulfur content. The sulfur content shall be used to calculate the potential uncontrolled SO_2 emissions as well as the control efficiency during the test. This information shall be submitted in the test report.

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure pursuant to Rule 62-297.620, F.A.C.

17. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 90 days after issuance of this final permit. Initial tests for each emission standard shall be conducted for CO, NOx, PM/PM10, SO_2, VOC, visible emissions, and the boiler thermal efficiency. In addition, an initial test shall be conducted for SAM to validate the emissions estimate. If initial SAM testing validates the estimated emissions, compliance for SAM shall be assumed as long as the boiler remains in compliance with the SO_2 standards. If initial SAM testing indicates higher emissions than estimated, the Department shall require additional testing. [Rule 62-297.310(7)(a)1., F.A.C.]

18. Annual Performance Tests: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct annual performance tests for CO, NOx, PM, VOC, and visible emissions to demonstrate compliance with the emissions standards specified in this permit. If the initial SO_2 performance test indicates SO_2 emissions are greater than 0.03 lb/mmBTU of heat input, the permittee shall conduct an annual performance test to demonstrate compliance with the SO_2 emissions standard. If the initial boiler thermal efficiency test, indicates an efficiency of less than 50%, the permittee shall conduct an annual test. [Rules 62-212.400 (BACT), 62-4.070(3), and 62-297.310(7)(a)4., F.A.C.]

19. Tests Prior to Renewal: During the federal fiscal year (October 1st to September 30th) prior to renewal of the air operation permit, the permittee shall conduct emissions performance tests for CO, NOx, PM, SO_2, VOC, visible emissions and boiler thermal efficiency to demonstrate compliance with the emissions standards and conditions specified in this permit. If the boiler thermal efficiency test, indicates an efficiency of less than 50%, the permittee shall conduct annual tests. If maintenance and repair result in regaining a boiler thermal efficiency of 50% or more, testing may revert back to the federal fiscal year prior to renewal. [Rules 62-212.400 (BACT), 62-4.070(3), F.A.C.]

20. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shake-down period of the boiler or air pollution control equipment. Shakedown periods shall not exceed 90 days after re-starting the unit. [Rule 62-297.310(7)(a)4., F.A.C.]

21. Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the scrubber pressure drop, the scrubber water supply line pressure, the scrubber water flow rate, the flue gas oxygen content, and the flue gas carbon monoxide content at 15 minute intervals. The permittee shall monitor and record the steam production rate, steam temperature, steam pressure, feed water flow rate, feed

water temperature, feed water pressure, and oil flow rate and calculate and record the bagasse consumption rate and the heat input for each run. [Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

22. Daily Operational Records: To demonstrate compliance with the performance requirements of this permit, the permittee shall record the following information in daily logs.

   a. **Startup and Shutdown**: The permittee shall record the time and date the boiler undergoes startup, shutdown, or malfunction. The permittee shall also log the time the boiler has achieved or regained normal operation.

   b. **Steam Parameters**: The steam temperature (psig), steam temperature (°F), and steam production rate (pounds per hour) shall be continuously recorded with a chart recorder.

   c. **Combustion Parameters**: The permittee shall record the oxygen and carbon monoxide contents of flue gas once normal operation is established after startup and at least once per hour of operation. Alternatively, the permittee may install an automated device to record these parameters.

   d. **Wet Scrubber Parameters**: The permittee shall record the following information once normal operation is established after startup and at least once every 3 hours: pressure drop across wet scrubber (inches of water column), scrubber spray nozzle pressure (psi), wet scrubber liquid flow rate (gpm). Alternatively, the permittee may install an automated device to record these parameters.

   e. **Oil Firing**: For each hour of oil firing, the permittee shall record the oil-firing rate (gallons per hour) for Boiler No. 4. In addition, the permittee shall maintain 3-hour and 24-hour block averages for the oil firing rate (gallons) of the combined operation of Boiler Nos. 1, 2, 3, and 4. Records for the oil firing rates may be observed and recorded by hand or automated monitoring equipment.

   f. **Oil Delivery**: For each fuel oil delivery, the permittee shall record and retain the following: the date; the gallons of fuel delivered; and a fuel oil analysis, including the heat content (mmBTU per gallon), the density (pounds per gallon), the sulfur content (percent by weight), and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable.

   g. **Monitoring Equipment**: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate, and maintain all monitoring equipment including steam flow meters, steam integrators, strip chart recorders, pressure gages, manometers, scrubber water flow meters, fuel oil flow meters, and all other monitoring devices used to demonstrate compliance with the conditions of this permit. Each device shall be calibrated at least annually. All calibrations and repairs shall be recorded as part of the Daily Operational Records.

   h. **Daily Summary**: For each day of operation, the permittee shall calculate and record the following by the end of the next workday.

      - Hours of operation for the day
      - Steam production rate: pounds per day and pounds per hour (daily average)
      - Heat input: mmBTU per day and mmBTU per hour (daily average)
      - Total oil fired for Boiler No. 4: gallons per day and maximum gallons per hour (as determined by data collected from the oil flow meter)

   All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

23. Monthly Operations Summary: To demonstrate compliance with the performance requirements of this permit, the permittee shall calculate and record the following within 10 calendar days of the end of the month.

- Hours of operation for the month
- Steam production rate: pounds per month
- Heat input: mmBTU per month, mmBTU per consecutive 12 months
- Wet bagasse consumption rate: tons per month and tons per consecutive 12 months
- Total oil fired for Boiler No. 4: gallons per month and gallons per consecutive 12 months
- For any monitored parameters with missing records, the permittee shall calculate and record the data availability (in percent) for the month.

All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. If recorded data indicates operation outside of the specified permit limits for steam production, heat input, wet bagasse consumption, or the oil firing rates, then the permittee shall submit a written notification and summary to the Compliance Authorities within ten (10) calendar days of recording the data. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

EMISSIONS UNIT 024. FUEL TANK

This portion of the permit addresses the following regulated emissions unit.

EU No.	Description
024	Fuel Oil Storage Tank for Boiler No. 4: Tank with a storage capacity of between 40,000 and 250,000 gallons of No. 6 fuel oil (or a superior grade) containing nor more than 0.7% sulfur by weight.

Note: The above description is based upon information provided in the application and is for informational purposes only.

{Permitting Note: Because this storage tank is greater than 40,000 gallons and was built after July 23, 1984, it is a regulated emissions unit subject to NSPS Subpart Kb, the New Source Performance Standards for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984. However, because this tank is used to store only fuel oil having a very low vapor pressure, it is subject solely to record keeping requirements.}

RULE APPLICABILITY

1. Applicability: NSPS Subpart Kb applies to each storage vessel with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.110b(a)]

2. Exemption from Portions of the NSPS: Vessels with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified in permit conditions 4 and 5 below. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.110b(c)]

RECORD KEEPING REQUIREMENTS

3. Sign: The permittee shall clearly mark this tank as the fuel oil storage tank for Boiler No. 4 and that only fuel oil containing 0.7% by weight or less may be added to and stored in this tank.

4. Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(b)]

5. Record Retention: The permittee shall keep a copy of this record for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(a)]

EMISSIONS UNIT 017. GRANULAR CARBON REGENERATIVE FURNACE

This portion of the permit addresses the following regulated emissions unit.

EU No.	Emission Unit Description
017	Granular carbon regenerative furnace (GRCF, S-12): Granular carbon is used to remove colorants and VOC emissions during the decolorization process. Heat from the furnace is used to drive off the colorants and VOC emissions and regenerate the carbon for reuse. VOC emissions are controlled by a direct flame afterburner and particulate matter emissions by a wet venturi/tray scrubber system: *Afterburner*: Zero Hearth Type (10'-9" OD x 8 HTH) furnace manufactured by BSP Thermal Systems, Inc. designed for the following specifications: 1200° F to 1400° F design temperature; 10,600 to 16,300 acfm flow rate; 0.5 to 0.75 seconds exhaust gas residence time; and a 92% destruction efficiency. The furnace and afterburner will fire approximately 90 gallons per hour and a maximum of 788,400 gallons per year. *Wet Scrubber System*: High energy venturi wet scrubber with tray type wet scrubber designed for the following specifications: 160° F and 4300 acfm outlet gas flow; 12 to 30 inches of water across venturi scrubber with a 36 gpm flow rate; 3 to 8 inches of water across the tray scrubber with 230 gpm flow rate; and a 97% particulate removal efficiency.

Note: The above description is based upon information provided in the application and is for informational purposes only.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Pursuant to Rule 62-212.400, F.A.C., this emissions unit is subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PERFORMANCE RESTRICTIONS

2. Hours of Operation: The hours of operation for this unit are not restricted (8,760 hours per year). [Rule 62-210.200, F.A.C., Definitions - PTE]
3. Allowable Fuel: Only No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner. The fuel sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. [Applicant Request; Rule 62-212.400(BACT), F.A.C.]

CONTROL EQUIPMENT

4. GCRF Afterburner: The permittee shall install, operate, and maintain an afterburner designed to destroy at least 92% of the VOC emissions during regeneration of the carbon bed as part of the decolorization process. The afterburner shall be designed with a control temperature of between 1200° F and 1400° F and an exhaust gas residence time of between 0.5 and 0.75 seconds. Excluding initial startup, shutdown, and malfunction, the afterburner temperature shall be maintained at 1200° F or higher except for up to 6 total minutes each hour during which the temperature shall not fall below 1000°F.[Rule 62-212.400 (BACT), F.A.C.]
5. GCRF Wet Scrubber: The permittee shall install, operate, and maintain a wet venturi / tray scrubber system designed to control at least 97% of the maximum particulate emissions during regeneration of the

carbon bed as part of the decolorization process. The venturi scrubber shall be designed for a pressure drop of between 12 to 30 inches of water column. The wet tray scrubber shall be designed for a pressure drop of between 3 to 8 inches of water column. Separate manometers (or equivalent devices) shall be installed, operated, and maintained to indicate the pressure drop across each control device. Operation outside of the specified operating range for any monitored parameter is not a violation of this permit, in and of itself. However, continued operation outside of the specified operating range for any monitored parameter without corrective action may be considered circumvention of the air pollution control equipment. [Rule 62-212.400 (BACT), F.A.C.]

EMISSION LIMITING STANDARDS

6. PM Standards: Emissions of particulate matter shall not exceed 0.7 pounds per hour (after control) from the granular carbon regenerative furnace as determined by EPA Method 5. In addition, visible emissions shall not exceed 10% opacity (excluding water vapor) as determined by EPA Method 9. [Rule 62-212.400 (BACT), F.A.C.]

7. VOC Standard: Emissions of volatile organic compounds shall not exceed 1.0 pound per hour (after control) from the granular carbon regenerative furnace as determined by EPA Method 25A reported in terms of propane. EPA Method 18 may be used to subtract methane from the total VOC measured by EPA Method 25A. [Rule 62-212.400 (BACT), F.A.C.]

PERFORMANCE TESTING REQUIREMENTS

8. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

   a. **EPA Method 5**, "Determination of Particulate Emissions from Stationary Sources".
   b. **DEP Method 9**, "Visual Determination of the Opacity of Emissions from Stationary Sources".
   c. **EPA Method 25A**, "Determination of Volatile Organic Concentrations."

   No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure pursuant to Rule 62-297.620, F.A.C.

9. Tests Required: Initial compliance with the allowable emission standards specified for this emissions unit shall be determined within 90 days after issuance of this final permit. Initial tests for shall be conducted for PM, VOC, and visible emissions to demonstrate compliance with the emissions standards. An annual test shall be conducted for visible emissions. After initial compliance is sufficiently demonstrated by initial PM and VOC performance testing, compliance may be assumed as long as the emissions unit remains in compliance with the visible emissions standard and monitoring requirements for the afterburner and wet scrubbing system. In addition, these tests shall be performed during the federal fiscal year (October 1st to September 30th) prior to renewing the air operation permit. [Rule 62-297.310(7)(a)1., F.A.C.]

10. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shake-down period of the emission unit or air pollution control equipment. Shakedown periods shall not exceed 90 days after re-starting the unit. [Rule 62-297.310(7)(a)4., F.A.C.]

11. Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the afterburner temperature and wet scrubber pressure differentials at 15-minute intervals. The tests shall be conducted at 90% of production capacity. [Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

12. Operations Log: At least once per shift, the permittee shall observe and record the afterburner temperature and the wet scrubber pressure differentials. The permittee may install automated equipment to continuously record these parameters. For any monitored parameters with missing records, the permittee shall calculate and record the data availability (in percent) for each month. [Rule 62-4.070(3), F.A.C.]

EMISSIONS UNITS 021. ALCOHOL EMISSIONS AND 023. PROPANE-FIRED SOCK HEATERS

This portion of the permit addresses the following regulated emissions units.

EU No.	EMISSIONS UNIT DESCRIPTION
021	Alcohol usage
023	Two propane-fired heaters are used to dry baghouse socks from the refinery and dryer baghouses. Each 0.165 mmBTU per hour heater fires approximately 1.75 gallons of propane per hour and a maximum of 15,295 gallons of propane per year.

Note: *The above description is based upon information provided in the application and is for informational purposes only.*

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Pursuant to Rule 62-212.400, F.A.C., this emissions unit is subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PERFORMANCE RESTRICTIONS

2. Allowable Fuel: Only commercially available propane shall be fired in the sock heaters. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.]

3. Visible Emissions: Visible emissions of 5% opacity or less from the sock heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are above 5% opacity, the permittee shall investigate the cause and take the necessary corrective actions. There is no initial or periodic testing required for this condition. [Rule 62-4.070(3), F.A.C.]

4. Alcohol Emissions: Alcohol usage from the sugar refinery shall not exceed 30,000 pounds per consecutive 12 months. Compliance shall be determined by the purchase records and the Material Data Safety Sheets (MSDS) for these products. The permittee shall calculate and record the alcohol emissions for submittal of the Annual Operating Report and at the request of the Department. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

5. Records: The permittee shall keep records sufficient to document the amount of propane fired in the heaters and alcohol used for reporting in the Annual Operations Report. [Rule 62-210.370(3), F.A.C.]

EMISSIONS UNITS 015, 016, 018, 019, 020, AND 022. MISCELLANEOUS PARTICULATE SOURCES

This portion of the permit addresses the following regulated emissions units.

EU No.	EMISSIONS UNIT DESCRIPTION
015	VHP sugar dryer with baghouse (S-11)
016	White sugar dryer with baghouse (S-10)
018	Vacuum Systems: Screening/distribution vacuum with baghouse (S-1); 100 lb bagging vacuum with baghouse (S-2); 5 lb bagging vacuum with baghouse (S-3)
019	Six conditioning silos with baghouses (S-7, S-8, S-9, S-13, S-14, and S-15)
020	Screening/distribution and powdered sugar/starch bins with baghouses (S-5, S-6, and S-16)
022	Packaging baghouse (S-4)

Note: *The above description is based upon information provided in the application and is for informational purposes only.*

CONTROL EQUIPMENT AND TECHNIQUES

1. Baghouses: The permittee shall install, operate, and maintain high efficiency baghouses designed to control at least 99.9% of the particulate matter emitted from each emissions unit and point. There are no limits on the hours of operation (8760 hours per year). [Applicant Request; Rule 62-212.400, F.A.C.]

PERFORMANCE RESTRICTIONS

2. Production Restrictions: No more than 2000 tons of refined sugar per day nor 730,000 tons of refined sugar per consecutive 12 months shall be packaged at this facility. In addition, no more than 2200 tons of refined sugar per day nor 803,000 tons of refined sugar per consecutive 12 months shall be loaded out from this facility. [Applicant Request; Rule 62-210.200 (Definitions - PTE), F.A.C.]

EMISSION LIMITING STANDARDS

3. PM Limits: The following table identifies the limits on particulate matter emissions from these emissions units.

EU No.	Point ID	DSCFM	lb/hour	Ton/Year
015	S-11	110,042	1.63	7.14
016	S-10	94,488	1.44	6.30
018	S-1	990	0.06	0.28
	S-2	872	0.06	0.28
	S-3	984	0.06	0.28
019	S-7	2641	0.06	0.25
	S-8	2641	0.06	0.25
	S-9	2641	0.06	0.25
	S-13	2641	0.06	0.25
	S-14	2641	0.06	0.25
	S-15	2641	0.06	0.25
020	S-5	2668	0.06	0.25
	S-6	8735	0.19	0.82
	S-16	6128	0.13	0.58
022	S-4	9589	0.21	0.90
Totals			4.20	18.33

4. Visible Emissions: As a surrogate for particulate matter, visible emissions shall not exceed 5% opacity from any of these emissions units or points. [Applicant Request; Rule 62-212.400, F.A.C.]

PERFORMANCE TESTING REQUIREMENTS

5. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

   a. **EPA Method 5**, "Determination of Particulate Emissions from Stationary Sources".

   b. **DEP Method 9**, "Visual Determination of the Opacity of Emissions from Stationary Sources".

   No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure pursuant to Rule 62-297.620, F.A.C.

6. Tests Required: Initial compliance with the visible emissions standard specified for these emissions units shall be determined within 90 days after issuance of this final permit. Compliance with the particulate matter emissions standard shall be assumed as long as the emission unit remains in compliance with the visible emissions standard. In addition, the visible emissions tests shall be performed during each federal fiscal year (October 1st to September 30th). [Rule 62-297.310(7)(a)1., F.A.C.]

7. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shake-down period of the emission unit or air pollution control equipment. Shakedown periods shall not exceed 90 days after re-starting the unit. [Rule 62-297.310(7)(a)4., F.A.C.]

EMISSION LIMITING AND PERFORMANCE STANDARDS

1. General Visible Emissions Standard: Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer, or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density if which is equal to or greater than 20% opacity. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C. [Rule 62-296.320(4)(b)1, F.A.C.]

2. 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.]

3. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants that cause or contribute to an objectionable odor. An objectionable odor is defined as 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) and 62-210.200(203), F.A.C.]

4. Plant Operation - Problems: If 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 notify the Department's district office and, if applicable, appropriate local program. The 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 permittee's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [Rule 62-4.130, F.A.C.]

5. Circumvention: No person shall circumvent any air pollution control device or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

6. Excess Emissions:

   (a) Excess emissions resulting from start-up, shutdown or malfunction of any emissions units 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.]

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

   Excess emission provisions can not be used to vary any NSPS requirement from any subpart of 40 CFR 60.

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

7. Test Methods: The appropriate test methods are specified in the permit, Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. The following test methods may also be required as part of these tests.

   a. **EPA Method 1**, "Sample and Velocity Traverses for Stationary Sources".

b. **EPA Method 2**, "Determination of Stack Gas Velocity and Volumetric Flow Rate".

c. **EPA Method 3**, "Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight".

d. **EPA Method 4**, "Determination of Moisture Content in Stack Gases".

8. 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 permittee, 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.]

9. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation 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 minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load 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.]

10. Calculation of Emission Rate: 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.]

11. Test Procedures: Test procedures and methods shall meet all applicable requirements of Rule 62-297.310(4), F.A.C. [Rule 62-297.310(4), F.A.C.]

12. Determination of Process Variables: [Rule 62-297.310(5), F.A.C.]

    (a) Required Equipment: The permittee 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.

13. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29

CFR Part 1910, Subparts D and E. Sampling facilities shall also conform to the requirements of Rule 62-297.310(6), F.A.C. [Rule 62-297.310(6), F.A.C.]

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial performance tests for NSPS sources and at least 15 days prior to any other required tests. Notification shall include 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 permittee. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

15. 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 permittee of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

16. Records: 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 DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

17. Data Availability: The minimum data availability for recorded monitoring data shall be at least 90% on a monthly basis. [Applicant Request]

18 Test Reports: The permittee 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 applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

19 Excess Emissions Report: If excess emissions occur, the permittee shall notify the Department within one working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-4.130, F.A.C.]

20. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each 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.]

21. Annual Operating Report for Air Pollutant Emitting Facility: The Annual Operating Report for Air Pollutant Emitting Facility shall be completed each year and shall be submitted to the Compliance Authority by March 1 of the following year. [Rule 62-210.370(3), F.A.C.]

SECTION IV.

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

BACT	-	Best Available Control Technology
DARM	-	Division of Air Resource Management
EPA	-	United States Environmental Protection Agency
DEP	-	State of Florida, Department of Environmental Protection
°F	-	Degrees Fahrenheit
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
SOA	-	Specific Operating Agreement
UTM	-	Universal Transverse Mercator

RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example: **[Rule 62-213.205, F.A.C.]**
Where: 62 - refers to Title 62 of the Florida Administrative Code (F.A.C.)
62-213 - refers to Chapter 62-213, F.A.C.
62-213.205 - refers to Rule 62-213.205, F.A.C.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001
Where: 099 - 3 digit number indicates that the facility is located in Palm Beach County
0221 - 4 digit number assigned by state database identifies specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV
Where: AC - identifies permit as an Air Construction Permit
AV - identifies permit as a Title V Major Source Air Operation Permit
099 - 3 digit number indicates that the facility is located in Palm Beach County
2222 - 4 digit number identifies a specific facility
001 - 3 digit sequential number identifies a specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456
Where: AC - identifies permit as an Air Construction Permit
AO - identifies permit as an Air Operation Permit
123456 - 6 digit sequential number identifies a specific permit project

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery
Hendry County

Air Permit No. 051-0003-009-AC (PSD-FL-272)
Boiler No. 4 and Refinery Expansion

1.0 EXISTING FACILITY

The existing facility consists of a sugar mill and refinery. Sugarcane is harvested from nearby fields and transported to the mill by train or truck. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze the juice from the cane. The cane 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 in the mill are the bagasse/oil-fired Boilers Nos. 1 through 6 with wet scrubbers for particulate matter control and the bagasse/oil-fired Boiler No. 7 with an electrostatic precipitator to control particulate matter. Air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, propane-fired heaters, conditioning silos, screening/distribution, vacuum systems, powdered sugar/starch bins, conveyors, a packaging system, and alcohol usage.

Because emissions of at least one criteria pollutant are greater than 250 TPY, the existing facility is considered a "major facility" with respect to Rule 62-212.400, F.A.C. - Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, a PSD review and a Best Available Control Technology (BACT) determination is required for each pollutant that will experience an emissions increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

2.0 PROJECT DESCRIPTION

The applicant, U.S. Sugar Corporation, proposes to expand the operation of Boiler No. 4 and the sugar refinery operation. The applicant requests the capability to operate Boiler No. 4 throughout the calendar year with a restriction on the permitted capacity of 2,880,000 mmBTU per year of heat input. This is a 25% capacity utilization increase of an additional 576,000 mmBTU of heat input per year. Previous operation was limited to approximately 160 days per year (3840 hours per year). The proposed project would increase operation at maximum capacity to approximately 200 days per year or an equivalent of 4800 hours per year. Although no physical modification of Boiler No. 4 will occur, the requested increase in operation will result in significant increases in pollutant emissions. The applicant also requests increased operation of the existing refinery operation, which consists of: sugar dryers; vacuum pickup units; conditioning silos; screening, distribution and packaging processes; and powdered sugar and starch bins. The application is also for the installation of three new sugar-conditioning silos and additional powdered sugar and starch silos, which are all, controlled by high efficiency baghouses.

Primarily as a result of increasing the operation of Boiler No. 4, this project will emit significant amounts of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) of Air Quality and a determination of the Best Available Control Technology (BACT) must be made for CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC in accordance with Rule 62-212.400, F.A.C. In addition, the expansion of the refinery operation constitutes a relaxation of federally enforceable permit limits, which also triggers PSD review. A detailed description of the PSD applicability analysis and BACT determination follows. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanies the Department's Intent to Issue Permit package.

3.0 PSD APPLICABILITY REVIEW

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program as approved by the EPA and defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with a National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. An existing facility is considered "major" with respect to PSD if the facility emits:

- 250 tons per year or more of any regulated air pollutant, OR
- 100 tons per year or more of any regulated air pollutant and it falls under one of the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C.

The existing facility is considered a PSD major source of air pollution because current potential emissions of at least one criteria pollutant are greater than 250 tons per year. Once a facility is classified as a PSD major source, new projects are reviewed for PSD applicability based on lower thresholds known as the Significant Emission Rates listed in Table 212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant in accordance with Rule 62-212.400, F.A.C. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to implement BACT for several "significant" regulated pollutants.

This project will be located in Hendry County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The following table summarizes the potential emissions increases and PSD applicability for this new project.

Pollutant	Project Potential Net Emissions[a] Increase (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	4075	100	Yes	Yes
NOx	292	40	Yes	Yes
PM/PM_{10}	116 / 108	25 / 15	Yes	Yes
SAM	7.6	7	Yes	Yes
SO_2	168	40	Yes	Yes
VOC	512	40	Yes	Yes

[a] - Based on applicant's revision submitted dated August 23, 1999.

Therefore, the proposed project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC emissions.

4.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The BACT determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall use its informed opinion to make this determination and shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must result in the selection of control technology that would at least meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

For this project, the following pollutants are subject to a BACT determination: CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC The applicant proposed control strategies for these pollutants in the PSD permit application. The Department relied on the following information in making its determination.

- Application for a PSD permit modification received on June 25, 1999 and all subsequent additional information submitted by the applicant and the applicant's consultant, Golder Associates, Inc. An accounting of the permit processing schedule is presented in the Technical Evaluation and Preliminary Determination.
- Comments from the National Park Service received August 11, 1999 and August 26, 1999.
- Comments from EPA Region 4 received on September 24, 1999.
- The previous PSD permit modification for USSC Clewiston Boiler No. 4 issued on August 9, 1995.
- Previous bagasse boiler BACT determinations issued by the Florida Department of Environmental Protection.
- Florida's Air Resource Management Systems (ARMS) database.
- EPA's RACT/BACT/LAER Clearinghouse database.

5.0 BACT DETERMINATIONS FOR BOILER NO. 4

5.1 CARBON MONOXIDE (CO)

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete combustion of bagasse and fuel oil. CO emissions are related to the flame temperature and are inversely proportional to NOx emissions . Lower flame temperatures lead to reduced NOx emissions, but generally higher CO and VOC emissions. The high moisture content of bagasse (approximately 55% by weight) tends to keep the flame temperature low, but the variability of the bagasse fuel can lead to fluctuations.

Applicant's Proposed CO BACT

The applicant did not identify any control options that were technically feasible for the control of CO emissions from a bagasse boiler. The applicant requested BACT to be "good combustion practices" with a corresponding CO emission standard of 6.5 pounds per mmBTU, as established in the 1995 PSD permit modification. The applicant identifies primary combustion controls as fuel firing rates, overfire air, excess air, and furnace temperature.

Department's CO BACT Determination

The increase in operation of Boiler No. 4 will result in a net increase in CO emissions of approximately 4000 tons per year. The Department is not aware of any CO BACT determinations for bagasse boilers in any other states. In Florida, the Department has made several BACT determinations including the following:

Unit	Date	Boiler Type	mmBTU/hr	Heat Release mmBTU/hr-ft^3	CO Standard lb/mmBTU
Osceola No. 3	1961	Inclined Grate	292	No Info.	3.5
Osceola No. 6	1981	Traveling Grate	379	32,661	6.5
Atlantic Bo. 5	1982	Traveling Grate	253	26,520	6.5
USSC Clewiston No. 4	1985	Traveling Grate	707	33,278	6.5
Osceola Cogen. Plant	1993	Spreader Stoker	760	18,500	0.35
Okeelanta Cogen. Plant	1993	Spreader Stoker	715	17,912	0.35
USSC Clewiston No. 7	1995	Traveling Grate	740	16,427	0.70

Clearly, the new boiler designs for the cogeneration plants and USSC Boiler No. 7 result in much lower CO emissions. This is mostly due to a more even furnace temperature and longer combustion gas residence time in the furnace. The designed heat release rate of a boiler is a measure of the combustion gas residence time, with a lower heat release rate providing a longer residence time. As shown, the older boilers have heat release rates nearly twice that of the newer units. Osceola's Boiler No. 3 is actually a converted cell type boiler and the design heat release rate is unknown. The purpose of the above table is to illustrate that high CO emissions from USSC Clewiston Boiler No. 4 are inherent to the original, older boiler design.

As indicated in several other projects for bagasse boilers, the Department is aware of five possible control methods for reducing CO emissions: Good combustion design, direct flame oxidation, catalytic oxidation, flue gas recirculation, and good combustion practices. According to the Department's ARMS database, CO emission limits range from 0.70 lb/mmBTU to approximately 7.0 lb/mmBTU for bagasse boilers. The following is a summary of the feasibility of these methods.

Good Combustion Design: As stated previously, the high CO emissions from USSC Clewiston Boiler No. 4 are inherent to the original, older boiler design. In the 1995 permit modification for CO emissions from this boiler, the Department had the applicant explore the possibilities of modifying the boiler furnace volume and/or combustion air feed system. The Department concluded that such modifications would be costly, impractical, and result in unknown reductions, if any. For this current project, the Department is unaware of any technological advances within the last four years that would change this position.

Direct Flame Oxidation: This technology has been applied to other industries and is capable of more than 98% control efficiencies. Additional fuel would need to be continually fired to maintain a high oxidation temperature for the large exhaust flow rate. Placing the direct flame burner after the scrubber would require even more fuel to reheat the exhaust gas to complete oxidation. Additional fuel combustion results in additional criteria pollutant emissions. It does not seem practical to burn more fuel to reduce CO emissions given the already high emissions of other pollutants.

Catalytic Oxidation: This control option requires a noble metal catalyst grid and an operating temperature of at least 500°F to achieve control efficiencies of 90% or greater. Typically, catalytic oxidation for combustion sources has been limited to clean exhaust gas streams such as natural gas-fired boilers or combustion turbines. An oxidation catalyst for this project would be prone to fouling by the high particulate load just after the boiler and poisoning by sulfur compounds from the firing of fuel oil. Installation after the wet scrubber is not feasible because the temperature is too low for catalytic oxidation to occur. Therefore, the Department does not believe this option is technically feasible for this project.

Flue Gas Recirculation (FGR): This control technique recirculates a portion of the exhaust gas stream back into the combustion zone for further oxidation. For some combustion sources, FGR may result in control efficiencies of perhaps 15% to 40%. However, FGR is very specific to the combustion source and has never been attempted for a bagasse boiler. During the 1995 modification for this boiler, the applicant obtained an estimate of nearly a million dollars to modify the boiler for FGR with no known result in CO reduction. The Department does not believe this control option to be demonstrated for bagasse boilers at this time.

Good Combustion Practice: The remaining control option is to use "good combustion practices" (GCP) to operate, monitor, and maintain the combustion process in order to minimize CO emissions. The most current GCPs for this boiler include the Operation and Maintenance Plan dated January 9, 1997. The plan includes many maintenance provisions to ensure that the boiler is operating at peak efficiency. It also requires training, adjusting bagasse feed rate based on combustion conditions, ensuring adequate combustion air, monitoring a stack video monitor for smoke, maintaining the bagasse moisture content below 55%, and a flue gas oxygen meter located in the boiler room to provide real time feedback to the operator. The purpose of the O&M Plan is to use the best possible operating practices in order to maintain CO and VOC emissions at the lowest possible levels without unduly increasing NOx emissions.

At this time, the Department is unable to identify any practical add-on control options for the reduction of CO emissions. Therefore, the Department will adopt the "good operating practices" (GCPs) identified in the O&M Plan for Boiler No. 4 dated January 9, 1997. In addition, the Department will also require boiler efficiency testing and exhaust gas process monitors for CO and oxygen. The boiler efficiency is a critical indicator of performance as well as maintenance. This test will be used to demonstrate that the boiler is being adequately maintained at an efficiency of 55% or greater. The oxygen process monitor will serve as an indicator of the excess air being supplied and the CO process monitor will provide an overall indicator of good combustion. The permit includes several CO emissions tests to correlate operations and emissions with the process monitors. The purpose of the process monitors is to provide the boiler operators with additional information in order to maintain control of the bagasse combustion process. This is critical because the determination of Best Available Control Technology for both CO and VOC emissions rely on the GCPs. Based on good combustion practices, the Department establishes the following emission standard as BACT.

"Emissions of CO shall not exceed 6.5 pounds per mmBTU of total heat input based on 3-hour test average as determined by EPA Method 10. Emissions performance testing for CO and NOx shall be conducted concurrently."

This limit is inclusive of any CO emissions from oil firing.

5.2 NITROGEN OXIDES (NOx)

Discussion of NOx Emissions

NOx is formed from the oxidation of nitrogen present in the combustion air and fuels. As discussed under CO, emissions of NOx are a function of the flame temperature, which may be affected by the high moisture content of bagasse (55% by weight). The Department established a limit of 0.9 lb/mmBTU of heat input for carbonaceous fuel burning facilities as Reasonably Available Control Technology for major sources located in nonattainment areas, pursuant to Rule 62-296.570, F.A.C.

Applicant's Proposed NOx Controls

The applicant did not identify any control options as technically feasible for the control of NOx emissions from a bagasse boiler. The applicant requested BACT to be "good combustion practices" with a corresponding NOx emission standard of 0.25 pounds per mmBTU, as established in the 1995 PSD permit modification. This limit was based on stack test data that showed emissions ranging from 0.03 to 0.16 lb/mmBTU with an average of 0.08 lb/mmBTU.

Department's NOx BACT Determination

The Department is aware of the following NOx control technologies.

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850°F. SCR is a commercially available option capable of 90% control efficiencies, but has never been applied to a bagasse boiler. The high particulate loading prior to the wet scrubber would cause catalyst fouling and result in reduced effectiveness. The reduced exhaust gas temperature after the wet scrubber is too low to complete the reduction reaction. Sulfur in the fuel oil would also poison the catalyst, degrading the performance over time. SCR is not a viable option for this project.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. The Okeelanta and Osceola biomass cogeneration plants use SNCR with urea injection for NOx control. However, the furnace temperatures are much higher than Clewiston Boiler No. 4. SNCR is not feasible because the exhaust temperature for this project is too low.

There are other emerging NOx controls such as Non-Selective Catalytic Reduction (NSCR) and SCONOx^{TM}, but these systems have limited if any applicability to bagasse-fired boilers. Again, NOx emissions are directly related to the boiler combustion design. Decreasing the flame temperature could further reduce NOx emissions, but at the expense of increasing CO and VOC emissions. As indicated above, two large biomass cogeneration plants have CO emissions nearly 20 times lower due to the much higher furnace temperatures. However, the furnace temperatures are so high that elevated NOx emissions required the installation of SNCR with urea injection for NOx control. At this time, the Department is unaware of any feasible control technology to reduce NOx emissions from bagasse boilers other than good combustion practices (GCP).

According to the Department's ARMS database, NOx emission limits for bagasse boilers range from 0.16 lb/mmBTU to 0.45 lb/mmBTU of heat input. The available stack test data (33 tests) for this boiler shows NOx emissions ranging from 0.03 to 0.16 lb/mmBTU for individual runs with an average of 0.08 lb/mmBTU. The three highest runs provide a 3-run average of 0.14 lb/mmBTU. The Department will allow a 25% margin above the highest single test run due to the known difficulties with controlling NOx emissions from bagasse boilers while also minimizing CO and VOC emissions. Therefore, the Department establishes the following NOx emissions standard.

> *NOx emissions shall not exceed 0.20 pounds per mmBTU of heat input based on a 3-hour test average as determined by EPA Methods 7 or 7E. Emissions performance testing for CO and NOx shall be conducted concurrently.*

Compliance will be demonstrated by conducting an annual stack test. This standard is well below the Department's RACT NOx standard for carbonaceous fuel burning equipment. Because of the relatively low annual potential NOx emissions from oil firing (< 12 tons per year), the Department will not establish a separate NOx standard for oil firing.

5.3 PARTICULATE MATTER (PM/PM_{10})

Discussion of PM/PM_{10} Emissions

Bagasse is the fibrous plant byproduct remaining from the raw sugar manufacturing process. The bulky carbonaceous material is burned as fuel in the sugar mill boilers to provide process steam as well as eliminate the remaining plant material. Bagasse combustion may result in high particulate matter emissions due to incomplete combustion. Fuel oil firing is used to supplement boiler operation and results in particulate matter emissions as well. Pursuant to Rule 62-296.410, F.A.C., the Department established a PM limit of 0.2 lb/mmBTU of heat input from carbonaceous fuel plus 0.10 lb/mmBTU of heat from fossil fuel.

Applicant's Proposed PM/PM_{10}

Historically, bagasse boilers in Florida, Louisiana, Hawaii, and Texas have used wet scrubbers to control emissions of particulate matter. Three recent projects in Florida have employed electrostatic precipitators (ESP): Okeelanta Cogeneration Plant, Osceola Cogeneration Plant, and the USSC Clewiston Mill's Boiler No. 7. However, all of these projects were new and greater emissions reductions were available to make them economically feasible. The applicant submitted a cost analysis for this project based on the costs for installing and operating the ESP for Boiler No. 7, scaled down by a ratio of the corresponding air flow rates. The estimated cost effectiveness was $8400 per ton of particulate matter removed based on the following assumptions: the current wet scrubber's average emission rate of 0.12 lb/mmBTU; the proposed ESP's emission rate of 0.03 lb/mmBTU; the requested heat input cap of 2,880,000 mmBTU per year; a 10-year life; and a 10% interest rate. The applicant concluded that this cost was unreasonably high and rejected the ESP. The applicant pointed out that Boiler No. 7 is much larger than Boiler No. 4 and is permitted to operate throughout the entire year, whereas Boiler No. 4 will be limited to an equivalent of 4800 hours per year at maximum capacity. The applicant proposed to retain the existing wet spray impingement scrubber system and current BACT particulate matter limit of 0.15 lb/mmBTU of heat input from bagasse firing.

Department's PM/PM_{10} BACT Determination

The Department recognizes that the Boiler No. 7 project established BACT for a new bagasse boiler. However, Boiler No. 4 is an existing boiler with particulate matter control and consideration in the cost analysis should be given to the current controlled emission rate. However, the Department disagrees with several assumptions made by the applicant.

- The wet scrubber emission rate should be equivalent to the permitted allowable rate of 0.15 lb/mmBTU and not the average tested rate.
- It is more reasonable to consider a cost recovery factor based on a 15-year life of this project with an interest rate of 7%.

To illustrate the effect of these assumptions, the Department used the applicant's costs adjusted for these new assumptions and calculated a cost effectiveness of approximately $5100 per ton of additional particulate matter removed. Considering this analysis and an estimated initial capital investment of approximately $3 million, installation of an ESP does not appear to be cost effective at this time. The Department concurs with the applicant that the existing wet spray impingement scrubber represents BACT for this project and establishes the following emissions standard.

> *Particulate matter emissions shall not exceed 0.15 pounds per mmBTU of heat input from firing bagasse nor 0.10 pounds per mmBTU from firing fuel oil. Compliance when firing both fuels shall be determined by prorating the emissions standards based on the heat input from each fuel.*

This standard shall also serve as a surrogate standard for PM_{10} emissions. Compliance with these standards shall be determined by the 3-run test average obtained by conducting EPA Method 5 and the performance test requirements specified in the permit. In addition, the permit requires monitoring of the scrubber liquid flow rate, the scrubber pressure drop, and the spray nozzle pressure. This limit is below the Department's existing rule for carbonaceous fuel burning equipment.

5.4 SULFURIC ACID MIST (SAM) AND SULFUR DIOXIDE (SO_2)

Discussion of SAM and SO_2 Emissions

Emissions of sulfur dioxide (SO_2) and sulfuric acid mist (SAM) result from the combustion of the bagasse and oil fuels. For many combustion sources, nearly all of the fuel sulfur is converted to SO_2 and/or SAM. However, based on industry tests, SO_2 emissions for firing bagasse are more than 90% lower than the maximum predicted rates. Industry consultants explain the significant difference between the calculated stoichiometric SO_2 emission rate and the measured SO_2 emission rate as adsorption of the SO_2 on the fine ash particulate generated from bagasse combustion. The SO_2 is then removed with the particulate by the wet scrubber.

Applicant's Proposed SAM and SO_2 BACT

Initially, the applicant proposed firing No. 6 fuel oil from the large common tank shared by most of the boilers, which may contain up to 2.5% sulfur by weight. However, any fuel oil fired in Boiler No. 4 would be replaced in the common tank with oil containing no more than 1.5% sulfur by weight. For firing bagasse, the applicant proposed to retain the current limit of 0.167 pounds per mmBTU. The Department pointed out that BACT determinations dating back to 1978 had determined oil containing no more than 0.7% by weight was available and cost effective. At the Department's request, the applicant performed the following cost analysis.

- Installation of a new tank, piping, and burners for 0.05% sulfur by weight distillate oil resulted in a cost effectiveness of $8120 per ton of SO_2 removed.
- Installation of a new tank, piping, and burners for 0.50% sulfur by weight oil resulted in a cost effectiveness of $10,525 per ton of SO_2 removed.
- Installing a new tank to fire only 0.7% sulfur by weight in Boiler No. 4 resulted in a cost effectiveness of $5691 per ton of SO_2 removed.
- Reducing the sulfur content in the common fuel tank to 0.7% sulfur by weight for all boilers resulted in a cost effectiveness of $697 per ton of SO_2 removed from Boiler No. 4 only.

The applicant's estimates were based on actual fuel usage, a baseline sulfur content of 1.5% sulfur by weight, a new tank life of 10 years, an interest rate of 10%, and actual fuel usage of approximately 100,000 gallons per year. The applicant concluded that the first three options are not cost effective. Although the fourth option is cost effective, the applicant claims that the Department cannot require lower fuel sulfur standards for the other boilers because they are not part of this modification and would result in unnecessary higher operating costs for the applicant. The applicant revised the proposal to include the replacement of oil fired in Boiler No. 4 with oil containing no more than 0.7% sulfur by weight in the common tank as well as a revised SO_2 limit for firing bagasse of 0.10 pounds per mmBTU. These changes would result in total potential SO_2 emissions from Boiler No. 4 of 168 tons per year, down from the 335 tons per year listed in the initial application.

<u>Department's SAM and SO_2 BACT Determination</u>

Fuel treatment and wet or dry flue gas desulfurization could be applied to this project to remove sulfur compounds. Fuel treatment involves the desulfurization of a fuel by a vendor prior to delivery to the user. A fuel sulfur limit may be specified in the air permit to establish the maximum potential SAM and SO_2 emissions. Although there are no known cases of add-on flue gas desulfurization applied to a bagasse boiler, this option is technically feasible. However, the Department favors inherently lower sulfur fuel oil as a pollution prevention strategy and believes that add-on controls would be cost prohibitive for the remaining available SO_2 reductions. Although the sulfur content of fuel oil can be minimized, the sulfur content of the bagasse is a function of the sugarcane crop. Therefore, separate SO_2/SAM standards will be established for fuel oil firing and bagasse firing.

Fuel Oil Standards: The Department considered the applicant's cost analyses, but believes it is more reasonable to consider the current allowable of 2.5% sulfur fuel oil to be the baseline, a 20-year tank life, a 7% interest rate, and the current allowable fuel usage of 500,000 gallons per year (because this project will increase operations). Based on these assumptions and the applicant's estimated equipment costs, the Department performed a cost estimate as summarized below.

Sulfur Content %	Option	Annual Costs $/Year	Reduction from 2.5% S TPY	$/Ton SO_2 Removed	$/Ton SO_2 Incremental Costs (0.7% S w/Com. Tank)
0.05	New Tank, etc.	$ 127,313	101.0	$ 1261	$ 3298
0.5	New Tank, etc.	$ 115,788	86.0	$ 1346	$ 6747
0.7	New Tank	$ 64,423	75.0	$ 859	NA
0.7	Common Tank	$ 41,575	75.0	$ 554	NA

Based on this revised analysis, the Department concludes that it is most cost effective to reduce the sulfur content of all of the fuel in the common tank to 0.7% sulfur by weight. Note that if reductions from the other boilers were considered, the cost per ton of SO_2 removed would be much lower. However, it is also cost effective to install a new tank to store and fire oil containing no more than 0.7%

sulfur for Boiler No. 4 only. Therefore, the Department will allow the applicant to select either option. The Department establishes BACT for emissions of SAM and SO_2 from oil firing to be the following.

> *Only fuel oil containing no more than 0.7% sulfur by weight shall be fired in Boiler No. 4. The permittee may install a new, dedicated storage tank for Boiler No. 4 to satisfy this requirement or purchase and store only fuel oil containing no more than 0.7% sulfur by weight in the common tank shared by Boiler Nos. 1, 2, 3, and 4. The permittee shall maintain sufficient records to show that only fuel meeting this specification was purchased and stored in the new tank or in the common tank after issuance of this permit.*

Bagasse Standards: The Department's ARMS database indicates a range of SO_2 emission standards from 0.17 to approximately 0.9 lb/mmBTU of heat input for bagasse boilers. According to the application, bagasse typically has a sulfur content of about 0.1% by dry weight, but can range from less than 0.1% up to 0.4% by dry weight. Based on the maximum proposed heat input of 633 mmBTU per hour and 55% moisture, bagasse containing 0.1% to 0.4% sulfur by weight would result in maximum SO_2 emissions of 0.25 to 1.01 lb/mmBTU. The applicant also provided information indicating that 13 tests have been performed on Boiler No. 4 when firing bagasse. The test data showed SO_2 emissions from 0.006 to 0.014 lb/mmBTU with an average of 0.008 lb/mmBTU. According to the industry, the mechanism providing the reduction is adsorption of the SO_2 onto the particulate ash generated from bagasse combustion combined with particulate removal in the wet scrubber. Based on the test data and calculated maximum emission rates, a reduction in SO_2 emissions between 94% and 99% seems to be achieved. Assuming the worst-case sulfur content (0.4% sulfur, dry weight) and a conservative control efficiency of 90%, the predicted SO_2 emissions would be 0.10 lb/mmBTU of heat input from bagasse. The applicant later requested a lower limit of 0.06 lb/mmBTU. Therefore, the Department establishes the following emission standard as BACT for firing bagasse.

"Emissions of SO_2 shall not exceed 0.06 pounds per mmBTU of heat input from bagasse as determined by EPA Methods 6, 6C, or 8."

The permit requires monitoring of the scrubber liquid flow rate, the scrubber pressure drop, and the spray nozzle pressure to ensure adequate control of SO_2 emissions.

Sulfuric acid mist (SAM) emissions are estimated to be less than 10% of the SO_2 emissions or approximately 0.01 lb/mmBTU of heat input. Reductions in SO_2 should result in similar reductions in SAM. Therefore, the Department will only require an initial performance test for SAM as determined by EPA Method 8 to verify this relationship. The SO_2 standard will serve as a surrogate standard for SAM. If the initial test results indicate SAM emissions above the expected rate, the Department may require additional testing to determine SAM emissions.

5.5 VOLATILE ORGANIC COMPOUNDS

Discussion of VOC Emissions

VOC emissions will result from incomplete combustion of bagasse and fuel oil. Typically, lower VOC emissions are realized with lower CO emissions due to better furnace combustion conditions. The Department established a limit of 5.0 lb/mmBTU of heat input for carbonaceous fuel burning facilities as Reasonably Available Control Technology for major sources located in nonattainment areas, pursuant to Rule 62-296.570, F.A.C.

Applicant's Proposed VOC BACT

The applicant did not identify any add-on control options that were technically feasible for the control of VOC emissions from a bagasse boiler. Initially, the applicant requested BACT to be "good combustion practices" with a VOC emission standard of 1.5 pounds per mmBTU, which the applicant accepted a lower RACT standard for major carbonaceous fuel fired boilers located in nonattainment areas in order to reduce Title V fees. The primary reason was due to a lack of data specific to Boiler No. 4. However, the submittal dated August 30, 1999, requests a lower limit of 0.5 lb/mmBTU based on other industry tests for similar bagasse boilers.

Department's VOC BACT Determination

The increase in operation of Boiler No. 4 will result in a net increase in VOC emissions of approximately 512 tons per year. The Department is not aware of any VOC BACT determinations for bagasse boilers in any other states. According to the Department's ARMS database, VOC limits for bagasse boilers range from 0.25 lb/mmBTU to 1.5 lb/mmBTU.

Add-on control options similar to those discussed previously for the control of CO emissions could be effective for the control of VOC emissions. However, they do not appear to practical or technically feasible for application to a bagasse boiler, again due to high particulate loading, high moisture content, low temperatures after the wet scrubber, and sulfur compounds generated by the fuels. The remaining option is "good combustion practices" (GCPs) to minimize emissions. The permit specifies that the GCPs specified for the control of CO will also be required for the control of VOC. Because of the variability of the industry data and the lack of specific stack test data for Boiler No. 4, the Department agrees to the VOC limit requested by the applicant. VOC emissions from oil firing are very small and will be included in the following emission standard, determined to be BACT for this project.

Emissions of regulated VOC shall not exceed 0.50 pounds (as propane) per mmBTU of total heat input from bagasse firing as determined by EPA Methods 18 and 25A. Total VOC emissions shall be determined by EPA Method 25A and reported in terms of lb/mmBTU as propane. EPA Method 18 may be used to determine emissions of methane and reported in terms of lb/mmBTU as propane. Emissions of regulated VOC shall be defined as the difference between the total VOC emissions and methane emissions (if measured) reported in terms of lb/mmBTU as propane.

This standard is below the Department's RACT standard for carbonaceous fuel burning equipment.

6.0 BACT DETERMINATION FOR REFINERY OPERATIONS

The refinery operations were originally issued a minor source air permit because the controlled project emissions did not originally trigger the PSD significant emission rates. However, upon completion of construction, potential PM_{10} emissions were above the significant emissions rate of 15 tons per year. U.S. Sugar tried to obtain a corresponding PM_{10} emissions offset by reducing the hours of operation of recently permitted Boiler No. 7. EPA objected to offsets from a boiler that had not yet begun normal operations. Therefore, the hours of operation of the refinery were limited to ensure PM_{10} emissions remained below 15 tons per year. A part of this current project is to regain the maximum capacity of the refinery to operate as well as adding new conditioning silos and sugar/starch bins controlled with baghouses. Because increasing the hours of operation of these emissions units is a relaxation of a federally enforceable condition used to avoid the BACT process, the emissions units will be reviewed as if never constructed, in accordance with Rule 62-212.400(1)(g), F.A.C.

The refinery operations will be evaluated as four main groups of air pollution sources: the granular carbon regenerative furnace, the propane fired sock dryers, the material handling processes controlled with baghouses, and the alcohol emissions.

6.1 BACT FOR THE GRANULAR CARBON REGENERATIVE FURNACE (GCRF)

Discussion

Part of the sugar refining process involves decolorization, which uses granular carbon to remove colorants and organics. A distillate oil-fired furnace is used to regenerate the carbon for reuse. This drives off the colorants and organics. To control PM and VOC emissions, U.S. Sugar installed a distillate oil fired afterburner followed by a wet scrubbing system consisting of a wet venturi scrubber and wet tray or plate scrubber.

Applicant's Proposed BACT

The applicant proposed the existing control systems and emissions as BACT for this expansion project with the following maximum emissions based on 8760 hours per year.

Pollutant	lb/hr	TPY	Comments
CO	3.0	13.1	Results from firing fuel in furnace and afterburner.
NOx	3.0	13.1	Results from firing fuel in furnace and afterburner.
PM/PM_{10}	0.7	3.1	From sugar processing; controls result in 98% reduction.
SO_2	0.5	2.2	Results from firing fuel in furnace and afterburner.
VOC	1.0	4.4	From sugar processing; controls result in 92% reduction.

The fuel fired is very low sulfur distillate oil containing no more than 0.03% sulfur by weight. The applicant requested that the sulfur content of this fuel be raised to 0.05% sulfur by weight so that a common fuel tank could be shared with Boiler No. 7. This would increase the SO_2 emissions to 3.58 tons per year, potentially a 1.43 ton per year net increase.

Department's BACT Determination

The Department concurs with the applicant that the existing afterburner and high efficiency wet scrubbing system is BACT for this emissions unit. The permit includes the following BACT standards and permit conditions.

> *Emissions of PM shall not exceed 0.7 pounds per hour (after control) from the granular carbon regenerative furnace as determined by EPA Method 5. Visible emissions shall not exceed 10% opacity as determined by EPA Method 9.*
>
> *Emissions of VOC shall not exceed 1.0 pounds per hour (after control) from the granular carbon regenerative furnace as determined by EPA Method 25A reported in terms of propane.*
>
> *Initial PM and VOC stack testing is required to demonstrate compliance with the controlled emission rates as well as prior to renewal of any operating permit. Parametric monitoring of the afterburner temperature and scrubber pressure differentials shall be required to ensure proper operation of the control equipment.*
>
> *Only low sulfur distillate oil (No. 2 or a superior grade) containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner.*

6.2 BACT FOR THE SOCK DRYERS

Discussion

Baghouse socks from the refinery and VHP dryer are washed and then dried using two 0.165 mmBTU per hour dryers fired with propane. Total, maximum propane consumption is 30,590 gallons per year for operation of both dryers.

Applicant's Proposed BACT

The applicant proposed the use of propane as BACT for these small emissions sources.

Department's BACT Determination

The Department agrees that BACT is the use of commercially available propane for the two sock dryers and will also include the following work practice standard as an indicator of good combustion for these units.

"Visible emissions of 5% opacity or less shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are above 5% opacity, the operator shall investigate the cause and take the necessary corrective actions."

This work practice standard does not require any initial or periodic testing.

6.3 BACT FOR THE MATERIAL HANDLING SOURCES

Discussion

The sugar refinery operations include drying, conditioning, screening, distributing, packaging, storing, spill cleanup, and shipping. Each of these processes has the potential to generate particulate matter.

Applicant's Proposed BACT

The applicant proposed the use of high efficiency baghouses to control each of these potential sources, as previously permitted. The hours of operation for all of these sources would increase to 8760 hours per year.

Department's BACT Determination

The Department agrees that BACT for these air pollution sources is control with a high efficiency baghouse. The permit includes the mass emissions rates in terms of pounds per hour and tons per year. Compliance with the mass emission rates may be assumed as long as each emissions point meets the following surrogate standard for particulate matter.

> *Visible emissions from each corresponding baghouse vent shall not exceed 5% opacity as determined by EPA Method 9.*

An annual visible emissions test shall be required for each emissions point. The Department may require an EPA Method 5 PM test if an emissions point fails a visible emissions test.

6.4 BACT FOR ALCOHOL USAGE

Discussion

The sugar refinery operations include usage of alcohol added to a slurry of sugar used for seed material in the vacuum pans. All of the alcohol is evaporated to the atmosphere as VOC emissions.

Applicant's Proposed BACT

The applicant proposed a maximum alcohol usage of approximately 30,000 pounds (15 tons) per year.

Department's BACT Determination

The Department agrees that BACT for this source is the following process limit.

"Alcohol usage shall not exceed 30,000 pounds per consecutive 12 months. Compliance shall be determined by record keeping."

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

Following are the BACT limits determined by the Department for this project. The emission limits or their equivalents, including the applicable averaging times, will be given in the specific conditions of the permit.

Pollutant	Controls	Emission Standard
EU 009 – Bagasse Boiler No.4		
CO	Good Combustion Practices	6.5 lb/mmBTU
NOx	Bagasse Firing, Good Combustion Practices	0.20 lb/mmBTU
PM/PM_{10}	Bagasse Firing, Good Combustion Practices	0.15 lb/mmBTU
	Oil Firing, Good Combustion Practices	0.10 lb/mmBTU
	Visible Emissions	VE < 20% opacity, except 40% for 2 min./hour
SO_2 (SAM)	Fuel Oil Sulfur Limit	0.7% sulfur by weight
	Bagasse Firing	0.06 lb/mmBTU
VOC	Good Combustion Practices	0.50 lb/mmBTU, as propane
EU 024 - NSPS Fuel Storage Tank for Boiler No. 4 (Record Keeping Requirements Only)		
EU 017 - Granular Carbon Regenerative Furnace with Afterburner and Wet Scrubber		
PM/PM_{10}	Controlled by Afterburner and Wet Scrubbing System	0.7 lb/hr
	Surrogate PM Standard	Visible emissions < 10% opacity
SO_2	Fuel Oil Sulfur Limit	0.05% sulfur by weight
VOC	Controlled by Afterburner	1.0 lb/hr, as propane
EU 023 - Two propane-fired sock dryers		
All	Fuel Specification	Commercially Available Propane
	Work Practice Standard for Good Combustion	Visible Emissions < 5% opacity
EU 021 – Alcohol Usage		
VOC	Alcohol Usage Limit	< 30,000 pounds per 12 months
EUs 015,016, 018, 019, 020, and 022 – Miscellaneous Particulate Sources		
PM	Surrogate Standard	Visible Emissions < 5% opacity

7.2 BACT EXCESS EMISSIONS ALLOWED

Pursuant to the Rule 62-210.700, F.A.C. and as approved in the Florida State Implementation Plan, the permit includes the following condition.

> *Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction of the combustion turbine shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. In no case shall excess emissions from startup, shutdown, and malfunction exceed two hours in any 24-hour period. If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. [Rule 62-210.700(1) and (6), F.A.C.]*
>
> *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.]*

Excess emissions provisions can not be used to vary any NSPS requirements from any subpart of 40 CFR 60.

8.0 COMMENTS FROM NPS AND EPA REGION 4

8.1 NPS COMMENTS

The National Park Service provided written comments on the proposed BACT regarding the ESP cost analysis, the proposed NOx standard, and 1.5% sulfur fuel as BACT. The Department addressed many of the NPS's concerns regarding the ESP cost analysis, but determined the costs of replacing the existing wet impingement scrubber with a new electrostatic precipitator as unreasonable at this time. The permit includes a NOx standard lower than requested by the applicant, but not as low as recommended by NPS. This is because of the competing nature of trying to reduce CO emissions while minimizing NOx emissions. The permit includes a much lower sulfur content limit of 0.7% by weight.

8.2 EPA REGION 4 COMMENTS

EPA Region 4 provided several written comments focusing primarily on the fuel oil sulfur limit and the cost analyses provided by the applicant. The Department concurred with many of EPA's recommendations regarding tank life, interest rate, baseline sulfur content, and fuel consumption rate. These were incorporated into the Department's revised analysis. EPA's strongest concern was that if BACT was established as fuel oil containing no more than 0.7% sulfur by weight, then Boiler No. 4 should not be permitted to burn oil containing a higher sulfur content. The Department believes the permit adequately addresses these concerns.

9.0 RECOMMENDATION AND APPROVAL

The permit project engineer and reviewing Professional Engineer is Jeff Koerner, P.E. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer at 850/414-7268 or the following address:

Jeffery J. Koerner

Jeffery F. Koerner, P.E., Project Engineer
New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

for C. H. Fancy, P.E.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Date: 11/19/99

Approved By:

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 11/19/99

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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 extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.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.

G.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.

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

G.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).

G.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.

G.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.

APPENDIX GCP - GOOD COMBUSTION PRACTICES PLAN

GOOD COMBUSTION PRACTICES

The following procedures were based upon the most recent update from Golder Associates of the Operation and Maintenance Plan for the Clewiston Boiler No. 4 dated January 9, 1997 and received by the Department January 13, 1997. A part of this plan is the attached Startup and Shutdown Procedures.

Purpose of GCP Plan

The determination of Best Available Control Technology for CO, NOx, and VOC emissions from Boiler No. 4 (EU-009) relied on "good combustion practices". The purpose of this document is to summarize the operational, maintenance, and monitoring procedures that will lead to the minimization of CO and VOC emissions and the optimization of NOx emissions, consistent with good combustion practices.

Preparation for Operations

1. Prior to each harvest season, the boiler proper, its air duct work, air heaters and scrubber are properly cleaned, inspected and repaired.
2. All refractory and boiler casing will be inspected and repaired where needed.
3. Outside of boiler tubes will have loose scale removed and boiler will be cleaned of loose scale, sand and other debris.
4. Boiler grates will be inspected and cleaned as well as being checked for mechanical operation.
5. All fans and fan drives will be inspected and repaired as needed.
6. All pumps and pump drives will be inspected and repaired as needed.
7. All oil burners will be cleaned and inspected as well as related oil piping, atomizing steam and air registers.
8. Prior to each harvest season, the skirt level of the scrubber is identified and marked on the outside so that a permanent reference is available.
9. Prior to each harvest season, all instruments for boiler operation and control are inspected, repaired and calibrated as required. This is recorded by the instrument shop in its repair log.

Boiler Operation and Controls

The senior most experienced boiler supervisor instructs other boiler room supervisors, boiler operators, and other appropriate personnel in proper boiler and scrubber operations so as to minimize stack emissions of CO and VOC, and so as to optimize stack emissions of NOx. This instructional program is presented prior to each harvest season and is included in the orientation and training provided to new boiler room employees. The training will impress upon supervisors and operators the importance of proper boiler operation in order to minimize emissions.

CO and VOC Controls

CO emissions are to be minimized by the proper application of Good Combustion Practices (GCP). To provide reasonable assurance that GCP are being employed:

1. The boiler operator will maintain steam rate at optimal or desired rate by controlling feed of bagasse fuel into the boiler. Combustion air to the boiler will be maintained at the highest possible level (resulting in sufficient excess air whenever feasible) in order to promote good combustion.
2. The boiler operator will periodically (at least once per hour) view the stack video monitor to visually confirm that good combustion is taking place. (Individual stack plumes are monitored continuously

through a closed circuit television system.) If an abnormal plume is observed, the operator will immediately take corrective action. The boiler operator will log the occurrence and duration of all such events in the boiler operation log, along with the corrective action taken. These records will be kept for a period of at least two years.

4. Process monitors shall be installed to monitor the oxygen (O_2)content and the carbon monoxide (CO) content of the boiler flue gas. The instrument readout will be located in the boiler control room to provide real time data to the boiler operator. The boiler operators will be instructed in the use of the O_2 and CO flue gas process monitors for combustion control and to ensure sufficient excess air levels. The boiler operators shall periodically observe each process monitor and adjust the boiler operation, consistent with good combustion practices. The specific conditions of this permit require additional CO testing after installation of the process monitors. This portion of the GCPs will be revised based on the test results.

NOx Controls

NOx emissions are to be optimized by the proper application of Good Combustion Practices (GCP). However, the application of GCP to minimize CO and VOC emissions may result in increased NOx emissions. This is because factors which promote good combustion and result in lower CO and VOC emissions, such as higher excess air and higher combustion temperatures, result in higher NOx emissions. This is the nature of the combustion process. Therefore, GCP to optimize NOx emissions is considered to be the same practices used to minimize CO and VOC emissions, as described above.

Miscellaneous

1. Several times per shift, the boiler grates and feeders are examined for proper distribution and any necessary operational changes are made. Any unusual observations are logged once per shift.
2. Once per day, on the day shift, the boiler will be given a walk-around inspection with the following items being checked and repaired as needed and in coordination with the production schedule: Fans, pumps, casing, ducting, and scrubber.
3. .On every shift burners are inspected and cleaned if dirty.
4. On every shift, precautions will be taken as necessary to control visible emissions of fugitive matter (dust and bagasse, etc.)

STARTUP AND SHUTDOWN PROCEDURE

The following procedure was submitted by U.S. Sugar as a supplement to the PSD application received on June 25, 1999.

During startup and shutdown of the boilers, excess CO, PM, NOx, and VOC emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions shall be taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 4. The boiler room foreman and operating personnel shall receive proper training on emissions control procedures at least once per year.

Cold Startup (approximately 4 to 5 hours)

1. Feed solid fuel into boiler construction chamber.
2. Start fire in combustion chamber using a propane torch designed for that purpose.
3. As boiler heats up and starts to make steam, continuously observe the boiler and scrubber water levels, and stack plume.

4. Light a burner at the lowest rate, continue to observe the stck plume and adjust if necessary, by adjusting fuel, atomizing steam, and air to obtain proper combustion.
5. Feed carbonaceous fuel from the mill to the boiler slowly at first; as the furnace gets hotter and the carbonaceous fuel is burning better, decrease fuel oil flow until burners can be turned off.
6. Continue to observe the stack plume, the scrubber water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain the optimum operating conditions.

Hot Startup (approximately 1 hour)

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Check the boiler and scrubber water levels, circulating pump and spray nozzles, and make sure they are functioning properly.
3. Light a burner, continue to observe the stack plume, water levels, and burners.
4. As the carbonaceous fuel fire gets hot enough to meet demand, reduce the burner fuel until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
5. Continue to observe the stack plume, scrubber water level, and carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain the optimum operating conditions.

Shutdown

1. Stop fuel flow to the boiler, reduce the forced draft, distributor air, overfire air, and induced forced draft.
2. Continue to observe the stack plume and water levels and make adjustments to maintain safe and optimum operating conditions.

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero A.A. for CHF

FROM: Jeff Koerner

DATE: November 19, 1999

SUBJECT: Final Permit No. 0510003-009-AC (PSD-FL-272)
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Expansion of Boiler No. 4 and Refinery Operations

The Final Permit is attached for your approval and signature to modify operations of bagasse Boiler No. 4 and several refinery emissions units at the existing sugar mill located in Clewiston, Hendry County, Florida. The final permit allows: full operation of the refinery emissions units; increased potential annual operation of Boiler No. by approximately 25%; operation without regard to sugarcane season; and restricted operation of Boiler No. 4 based on heat input, fuel consumption, and steam production rather than hours.

Boiler No. 4: BACT for CO, NOx, and VOC was determined to be "good combustion practices", which requires installation of flue gas meters to monitor CO and O2 levels for combustion efficiency. BACT for PM/PM10 was 0.15 lb/mmBTU controlled by the existing wet scrubber. Although this remained unchanged from the previous determination, the permit requires increased monitoring of the scrubber pressure drop, scrubber water line pressure, and scrubber water flow rate. BACT for SO2 when firing bagasse was reduced from 0.166 lb/mmBTU to 0.05 lb/mmBTU based on existing test data. BACT for SO2 when firing fuel oil was determined to be firing a fuel oil containing no more than 0.7% sulfur by weight, which is a reduction from the previous determination of 1.5% sulfur by weight.

Refinery Emission Units: PM BACT for the sugar handling equipment, silos, bins, etc. was determined to be no visible emissions with particulate matter controlled by high efficiency baghouses. For the granular carbon regenerative furnace, BACT for CO, NOx, PM/PM10, and VOC was determined to be a direct flame afterburner followed by a wet scrubbing system. BACT for SO2 was determined to be the use of very low sulfur distillate oil.

Initially, the applicant submitted an air quality analysis based on a non-guideline model (ISC Prime), which requires approval of EPA Region 4. This was done because of modeled problems with CO, PM, and SO_2 related to potential downwash from a recently constructed building. During the application process, it became apparent that EPA may require several months before approval could be granted. U.S. Sugar needed the permit modification early in the upcoming sugarcane season to avoid noncompliance with restrictions on operation resulting from extended operation last year. So the applicant submitted an "interim" air quality analysis based on the standard guideline model (ISCST3), reduced fuel sulfur content in other boilers at the facility, and increased stack heights. The Department based its intent to issue the Draft Permit on this analysis in an effort to begin steps toward resolving the modeled potential problems with CO, PM, and SO_2. After discussing this with EPA Region 4, the final permit was revised to require U.S. Sugar to modify this permit based on the final modeling analysis. Prior to the modification, U.S. Sugar would continue to fire low sulfur fuel oil in Boilers 1 through 4 and complete construction of the increased stack heights within a year.

The Public Notice of Intent to Issue was published in The Clewiston News on October 13, 1999. No comments on the Draft Permit were received from the public, the South District DEP Office, or the NPS. The applicant and EPA submitted comments that resulted in minor changes to the Final Permit. The comments are summarized in the attached Final Determination with the Department's response.

I recommend your approval and signature. Day 90 for this project is January 15, 2000.

Attachments

CHF/AAL/jfk