FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 4, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Draft Permit No. 051-0003-009-AC (PSD-FL-272)
U.S. Sugar Clewiston Mill
Expansion of Boiler No. 4 and Refinery Operations

Dear Mr. Brinson:

Enclosed is one copy of the Department's Intent to Issue Air Construction Permit and the proposed Draft Permit to modify the operations for the U.S. Sugar Clewiston Mill located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The Technical Evaluation and Preliminary Determination and the Public Notice of Intent to Issue Air Construction Permit are also included.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to Jeff Koerner, P.E., New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff at 850/414-7268.

Sincerely,

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

CHF/jfk

Enclosures

In the Matter of an
Application for Permit by:

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

Authorized Representative:
Murray T. Brinson, Vice President

Draft Permit No. 051-0003-009-AC
PSD Permit No. PSD-FL-272

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

Project: Expansion of Boiler No. 4
and Refinery Operations

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft permit attached) for the proposed project, detailed in the application specified above and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, U.S. Sugar Corporation, applied on June 25, 1999 to the Department for an air construction permit for its Clewiston Sugar Mill and Refinery located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The proposed permit allows a 25% increase in annual heat input for Boiler No. 4, operation of Boiler No. 4 throughout the calendar year, operation of all refinery sources at full capacity (8760 hours per year), the addition of powdered sugar and starch bins, and the addition of new sugar conditioning silos. The initial application included an air quality analysis based on an air dispersion model (ISC-Prime) that has not yet been approved by the EPA. The EPA Region 4 office is currently reviewing the model and air quality analysis for a case-by-case approval. Because of the importance to the applicant in obtaining this permit prior to the new sugarcane grinding season, the applicant also submitted an alternate air quality analysis based on the EPA-approved air dispersion model (ISCST3), decreased fuel sulfur content for Boiler Nos. 1 through 3 not directly subject to this modification, and a proposed increase of stack heights to 213 feet for Boiler Nos. 1 through 4. The Draft Permit contains conditions that include these additional changes should EPA Region 4 reject either the model or the air quality analysis.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to modify the operations as requested in the application.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

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

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

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

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

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

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

Executed in Tallahassee, Florida.

CH Fancy

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-6-99 to the person(s) listed:

Murray T. Brinson, U.S. Sugar*
Mr. David Buff, Golder Associates
Mr. Phil Barbaccia, DEP - South Florida District Office
Mr. Gregg Worley, EPA Region 4 Office
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.

[signature] (Clerk) 10-6-99 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 051-003-009-AC (PSD-FL-272)

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

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the U.S. Sugar Corporation for the Clewiston Sugar Mill and Refinery located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The applicant's Authorized Representative is Murray T. Brinson, Vice President of U.S. Sugar Corporation. The mailing address is 111 Ponce DeLeon Avenue, Clewiston, FL 33440. The proposed Draft Permit allows a 25% increase in annual heat input for Boiler No. 4, operation of Boiler No. 4 throughout the calendar year, the increase of all refinery operations to full capacity (8760 hours per year), the addition of powdered sugar and starch bins, and the addition of new sugar conditioning silos. A Best Available Control Technology (BACT) determination was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

The Department has determined that the only viable control option at this time is good combustion practices to reduce emissions of CO, NOx, and VOC from the existing bagasse/oil-fired Boiler No. 4. The Draft Permit requires the installation and operation of CO and oxygen flue gas process monitors to provide feedback to the boiler operators as an indicator of the combustion efficiency. The existing wet spray impingement scrubber will control emissions of PM/PM10 and SO2. The allowable fuel oil sulfur content was reduced form 1.5% to 0.7% sulfur by weight to further control emissions of SAM and SO2 from oil firing. The decolorization process in the refinery operations includes a carbon bed to remove colorants and organics from the gas stream. Particulate matter is controlled by a wet venturi/tray scrubber system. Emissions of VOC are controlled by a direct flame afterburner. All material handling operations are controlled by high efficiency baghouses. The maximum potential emissions in tons per year (TPY) will be: 9373 TPY of CO; 277 TPY of NOx; 252 TPY of PM; 17 TPY of SAM; 171 TPY of SO2; and 724 TPY of VOC.

The initial application included an air quality analysis based on an air dispersion model (ISC-Prime) that has not yet been approved by the EPA. The EPA Region 4 office is currently reviewing the air quality analysis based on this model for a case-by-case approval on this project. Because of the importance to the applicant in obtaining this permit prior to the new sugarcane grinding season, the applicant also submitted an alternate air quality analysis based on the EPA-approved air dispersion model (ISCST3), decreased fuel sulfur content for Boiler Nos. 1 through 3 (not directly subject to this modification), and a proposed increase of stack heights to 213 feet for Boiler Nos. 1 through 4. The Draft Permit contains conditions that include these additional changes should EPA Region 4 reject the air quality analysis based on the non-approved model.

The results of the alternate air quality impact analysis using the EPA-approved ISCST3 model are presented below. Emissions from the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment Consumed (μg/m³)		Allowable Increment (μg/m³)	Percent Increment Consumed
PM_{10}			
24-hour	21	31	67
Annual	0	17	0
SO_2			
3-hour	345	512	67
24-hour	31	91	34
Annual	3	20	15

The maximum predicted PSD Class I increments of SO_2 in the Everglades National Park, consumed by all sources in the area, including this project, will be as follows:

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PSD Class I Increment Consumed (μg/m³)		Allowable Increment (μg/m³)	Percent Increment Consumed
SO_2			
3-hour	18	25	72
24-hour	4.1	5	82
Annual	0.33	2	17

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

Department of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida, 32301
Telephone: 850/488-0114

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

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Department's reviewing engineer for this project, Jeff Koerner, New Source Review Section, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

U.S. Sugar Corporation
Clewiston Sugar Mill and Refinery

Boiler No. 4 and Refinery Expansion
Emissions Units 009 and 015 through 24

Hendry County

Facility I.D. No. 051-0003

Draft Permit No. 051-0003-009-AC

(PSD-FL-272)

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

October 4, 1999

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

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

1.2 Reviewing and Processing Schedule

06/25/99 Department received the PSD air pollution construction permit application.

06/29/99 Department mailed copies of the PSD application to EPA Region 4 and NPS.

07/02/99 Department mailed revised cover letter to EPA Region 4 and NPS correcting project description.

07/22/99 Department requested additional information (No. 1).

07/27/99 Department received copy of final permit 051-0003-008-AC for the refinery operations from the South District Office.

08/04/999 Department received additional information (No. 1) from the applicant.

08/11/99 Department received e-mail from NPS commenting on BACT analysis and forwarded to applicant's consultant.

08/18/99 Department requested additional information (No. 2).

08/26/99 Department received comments from NPS on BACT and air dispersion modeling analysis.

08/27/99 Department faxed NPS comments to applicant's consultant.

08/30/99 Department received additional information (No. 2) from the applicant.

09/01/99 Department received e-mail from Golder supplying information on GRCF.

09/14/99 Department received additional information (No. 3) from the applicant, modifying previous submittal.

09/17/99 Department received draft comments from EPA Region 4 regarding the BACT analysis for SO_2 and forwarded to Golder.

09/17/99 Department received proposed conditional language for the Draft Permit and Preliminary Determination based on alternate modeling scenario with ISCST3, increased stack heights, and low sulfur fuel oil in the common tank.

09/22/99 Department received summary tables of modeling scenarios for permit conditions contingent on EPA's approval/rejection of the ISC Prime air dispersion model. Application complete.

2.0 EXISTING FACILITY INFORMATION

2.1 Existing 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.

2.2 Facility Location

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.

2.3 Standard Industrial Classification Codes (SIC)

Industry Group No.	20	Food and Kindred Products
Industry No.	2061	Raw Cane Sugar

2.4 Regulatory Categories

Power Plant Siting: Not applicable.

Title III – HAP: The facility is not believed to be a major source of hazardous air pollutants.

Title IV - Acid Rain: Not applicable.

Title V – Major Source: The facility is classified as a "major" source of air pollution with respect to Title V of the Clean Air Act because emissions of at least one regulated 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 (TPY).

PSD Major Source: The facility is a "major facility" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality program because emissions of at least one criteria pollutant are greater than 250 tons per year. Pursuant to Rule 62-212.400, F.A.C., each modification to a PSD major source requires a PSD review and determination of the Best Available Control Technology (BACT) if the resulting emissions increases are greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

NSPS Sources: The existing facility includes new fuel oil storage tank that is subject to regulation under the federal New Source Performance Standards in 40 CFR 60, Subpart Kb (Volatile Organic Liquid Storage Vessels, Including Petroleum Liquid Storage Vessels, for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984) and adopted by reference in Rule 62-204.800, F.A.C. 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.

3.0 PROPOSED PROJECT

3.1 Project Description

The applicant, U.S. Sugar Corporation, requests the following changes in order to expand the operation of Boiler No. 4 and the sugar refinery operation.

- **Emissions Unit 009**: Increase total heat input by 25% to Boiler No. 4 from 2,304,000 to 2,880,000 mmBTU per year. (However, the maximum heat input will decrease from 777.2 to 630 mmBTU per hour and the steam production will decrease from 368,500 to 300,000 pounds per hour.) Increase Boiler No. 4 operation from 160 days per year (3840 hours per year) to 200 days per year (4800 hours per year) based on maximum operation. However, operation of Boiler no. 4 will be restricted only by heat input. Allow operation of Boiler No. 4 throughout the calendar year and not just during the sugarcane crop season. (Required air dispersion modeling for the entire year.)

- **Emissions Unit 015**: Increase hours of operation of VHP dryer with baghouse from 3690 to 8760 hours per year.
- **Emissions Unit 016**: Increase hours of operation of white sugar dryer with baghouse from 7680 to 8760 hours per year.
- **Emissions Unit 017**: Increase hours of operation of granular carbon regenerative furnace with afterburner and wet scrubber from 3690 to 8760 hours per year.
- **Emissions Unit 018**: Increase hours of operation of three existing vacuum systems from 7680 to 8760 hours per year.
- **Emissions Unit 019**: Add three sugar-conditioning silos with baghouses to existing three silos and increase hours of operation to 8760 hours per year.
- **Emissions Unit 020**: Add new powdered sugar/starch bins with baghouses and operation of 8760 hours per year. Increase hours of operation for screening/distribution baghouses to 8760 hours per year.
- **Emissions Unit 021**: Establish maximum annual alcohol emissions from mill and refinery at 15 tons.
- **Emissions Unit 022**: Increase hours of operation of packaging system with dust collector from 7680 to 8760 hours per year.
- **Emissions Unit 023**: Permit two propane-fired baghouse sock dryers at 8760 hours per year.
- **Emissions Unit 024**: Add a new fuel storage tank to serve Boiler No. 4.

Although no physical modifications will occur to Boiler No. 4 or the refinery operations, the proposed project results in significant increases in pollutant emissions 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). This is primarily the result of the 25% increase in operation of Boiler No. 4. 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 a PSD review as if these emissions units had never been constructed, pursuant to Rule 62-210.400(1)(g), F.A.C. A detailed description of the PSD applicability analysis is provided in the Department's BACT determination, which is Appendix BD of the Draft Permit.

3.2 Project Emissions

Table 3.2 This table summarizes potential emissions increases and the resulting PSD applicability.

Pollutant	Proposed Project Net Emissions Increase (TPY)	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	148	40	Yes	Yes
VOC	512	40	Yes	Yes
Lead	0.27	0.6	No	No
Mercury	0.048	0.1	No	No
Beryllium	5.47 E^{-06}	4.0 E^{-04}	No	No

Note: Based on applicant's latest submittal.

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

4.0 RULE APPLICABILITY

4.1 PSD Review

As previously discussed, the existing facility is considered a PSD major source and is 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). In addition, the proposed project will emit pollutants exceeding the Significant Emission Rates defined in Table 212.400-1, F.A.C. Therefore, the project is subject to a review for the Prevention of Significant Deterioration of Air Quality accordance with Rule 62-212.400, F.A.C.

The PSD review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each significant pollutant (CO, NOx, PM/PM_{10}, SAM, SO_2 and VOC). This evaluation is provided in detail in *Appendix BD* of the proposed Draft Permit. The second part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4.2 State Regulations

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

Chapter 62-4	Permitting Requirements
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution

Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards (including general emission limiting requirements as well as standards for carbonaceous fuel burning equipment.)
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

4.3 Federal Regulations

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

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 52.166	Prevention of Significant Deterioration
40 CFR 60	NSPS Subpart Kb – Volatile Organic Liquid Storage Vessels, Including Petroleum Liquid Storage Vessels, for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 (Subject only to the minimal record keeping requirements regarding tank volume and fuel stored.)
40 CFR 60	Subpart A, General Provisions for NSPS Sources
40 CFR 72	Acid Rain Permits
40 CFR 73	Allowances
40 CFR 75	Monitoring
40 CFR 77	Acid Rain Program - Excess Emissions

5.0 SUMMARY OF BACT DETERMINATION

At this time, the Department was unable to identify any technically feasible, commercially available add-on control equipment for existing bagasse/oil-fired Boiler No. 4. Emissions of particulate matter will continue to be controlled with the existing wet spray impingement scrubber. Emissions of carbon monoxide and volatile organic compounds are minimized by good combustion practices while optimizing emissions of nitrogen oxides. Emissions of sulfur dioxide when firing bagasse are reduced by adsorption onto ash particulate and removal in the wet scrubber. Potential emissions of sulfur dioxide when firing fuel oil are reduced by lowering the fuel sulfur content to 0.7% sulfur by weight. Based on existing stack test data, the Department also lowered emissions standards for nitrogen oxides, sulfur dioxide, and volatile organic compounds for bagasse firing while still allowing for a sufficient margin of compliance. The Draft Permit identifies the "good combustion practices" required to minimize emissions and requires installation of oxygen and carbon monoxide process monitors to provide real feedback to the operators. The lower emissions standards, annual performance tests, process monitors, and more frequent monitoring of control systems by the operators should result in a reduction of short-term (hourly) actual pollutant emissions. A detailed analysis of the BACT Determination is presented in *Appendix BD* of the Draft Permit. The following table summarizes the resulting emissions standards.

5.1 Summary of Emissions Standards

The standards identified in the following table (or the equivalents) are included in the specific conditions of the draft permit.

Pollutant	Fuel / 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/PM10	Bagasse firing, good combustion practices	0.15 lb/mmBTU
	Oil firing, good combustion practices	0.10 lb/mmBTU
SO2 (SAM)	Fuel oil sulfur limit	0.7% sulfur by weight
	Bagasse firing	0.10 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/PM10	Controlled by afterburner and wet scrubbing system	0.7 lb/hr
	Surrogate PM standard	Visible emissions < 5% opacity
SO2	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	Commercial 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	Baghouse, surrogate standard	Visible emissions < 5% opacity

5.2 Emissions Comparison

The following table presents a summary of the maximum emissions of the project as originally proposed and the future maximum potential emissions as proposed for issuance of the Draft Permit.

Future Maximum Potential Project Emissions

Pollutant	Original Proposal (TPY)	Proposed Draft Permit (TPY)
Be	$6.9\ E^{-06}$	$6.9\ E^{-06}$
CO	9373	9373
Hg	0.055	0.055
NOx	371	277
Pb	0.64	0.64
PM/PM10	252	252
SAM*	14	17
SO2	366	171
VOC	2180	724

* *The Department estimated SAM emissions as 10% of the total SO_2 emissions and included SAM emissions from the other emissions units, not just the boiler.*

5.3 Permit Conditions Related to Modeling Analyses

The applicant performed the required air dispersion modeling for compliance with the ambient air quality standards and PSD increments. However, the initial modeling performed with the EPA-approved ISCST3 model showed potential problems for CO, SO_2 and PM. The applicant indicated that this was a result of two primary factors:

- Ambient background concentrations for CO were based on ambient monitoring data for the urbanized coastal Palm Beach County with high automobile traffic patterns, which is not truly representative of the much more rural western Hendry County where the sugar mill is located; and
- The ISCST3 model is ultra-conservative with respect to the downwash algorithm and the area of influence within the building wake region.

Therefore, in the initial PSD application, the applicant included an analyses based on ISC-Prime, a model that EA has helped develop, but that has not yet been approved for regulatory use. The ISC-Prime model includes a new downwash algorithm that predicts a less conservative downwash concentration for a stack located between 60% to 100% of the maximum distance from a given building wake region. Beyond this maximum distance no down wash is considered. Reportedly, this is the only difference between the ISC-Prime model and the ISCST3 model. The applicant also points out that EPA is moving towards approval of the ISC-Prime model and intends to hold a national conference to include a discussion of the new model. In addition, the ISC-Prime model has been approved by other EPA regional offices on a case-by-case basis for specific projects.

During the application process, it was agreed that the Department would allow the use of this model only if the EPA Region 4 office approved the new model and analysis on a case-by-case basis for this project. The applicant has been working with EPA Region 4 staff, but the model and analysis has yet to be approved. It is important to the applicant to obtain this permit modification prior to the upcoming sugarcane season (approximately October through June). Therefore, the applicant requested that the Department approve the project based on an alternate modeling analysis that included: the EPA-approved ISCST3 model; a reduction in the sulfur content of fuel oil from 2.5% to 1.5% sulfur by weight for Boiler Nos. 1, 2, and 3; and increasing the stack heights of Boiler Nos. 1, 2, 3, and 4 to 213 feet. The proposed alternate scenario indicated compliance with the ambient air quality standards and PSD increments. Further, the applicant requested that these more stringent conditions be required only if EPA Region 4 rejected the ISC-Prime modeling analysis.

Pursuant to Rule 62-212.300(1), F.A.C., the Department shall not permit the construction or modification of any emissions unit or facility that would cause or contribute to a violation of any ambient air quality standard. Because EPA Region 4 has not yet approved the ambient air quality analysis based on the ISC-Prime model, the Department does not have the reasonable assurance that the proposed project will comply with the ambient air quality standards and PSD increments. However, the Department does consider the following items:

- Although the project will result in a 25% increase in potential annual operation of Boiler No. 4, the maximum hourly heat input and steam production will actually be decreased.
- The building causing the high downwash concentration is associated with the refinery operations, which was permitted as a minor modification (10/25/96) requiring no ambient air quality analysis.

- The Department determined that the BACT for SO_2 when firing fuel oil in Boiler No. 4 was oil containing no more than 0.7% sulfur by weight.
- The new proposed stack heights are less than GEP stack heights, but appear to provide enough dispersion to comply with the ambient air quality standards and PSD increments.
- The most recent discussions with the EPA Region 4 staff indicate that the ISC-Prime model will eventually be approved by EPA.

Based on the ISCST3 model results, the predicted exceedances exist for this facility whether or not the permit modification is issued. Apparently, the construction of a new building associated with the refinery operations is creating a building wake region requiring the consideration of downwash concentrations. Built several years ago as part of a minor source construction permit, this situation was never previously modeled. When this has occurred in the past for other facilities, the Department has allowed fuel sulfur reductions and dispersion techniques to regain compliance. The Department has also allowed a period of time sufficient to modify the operations, perform the necessary work, and conduct further modeling to verify compliance. Based on this information, the Department believes it is reasonable to issue the Draft Permit contingent on the following condition.

"7. <u>EPA Approval of ISC Prime Model</u>: If EPA Region 4 ***does not*** approve the ISC Prime model prior to issuance of this final permit, or rejects the air quality analysis for this project based on the ISC Prime model, the permittee shall comply with the following 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 for the common tank shared by Boiler Nos. 1, 2, 3, and 4. (The permittee may install a separate tank for Boiler No. 4.)

(b) Within 180 days after issuance of this final permit, the permittee shall submit final plans for increasing the stack heights for Boiler Nos. 1, 2, 3, and 4 to 213 feet. Modification of all stacks shall be complete with one year after issuance of this final permit.

However, if EPA approves the use of the ISC Prime model *and* the corresponding air quality analysis for this project within 180 days of issuance of this final permit, specific conditions 7.(a) and 7.(b) shall no longer apply. The permittee may request that this permit be revised to remove specific condition 7. [Applicant Request and Rule 62-4.070(3), F.A.C.]"

This establishes the fuel sulfur content of Boiler Nos. 1, 2, and 3 at the same level as Boiler No. 4, which was determined to be BACT for that unit. The condition allows a reasonable period of time for EPA Region 4 to either approve or reject the ISC-Prime model or analyses *and* for the applicant to regain compliance if the model or analyses is rejected. *Attachment A* to this document includes the applicant's discussion of the ISC-Prime model and summary tables comparing the analysis of the existing facility based on ISCST3, the analysis based on ISC-Prime, and the analysis based on ISCT3 with additional conditions. Further details of the air quality analysis are provided in the following section.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 <u>Introduction</u>

The air quality impact analysis section will only present the results of the alternate modeling scenario mentioned in section 5.3, which is based upon the EPA and department-approved ISCST3 model. As discussed in section 5.3, the alternate scenario is based on a reduction of sulfur content of fuel oil used in Boiler 4 to 0.7% sulfur by weight and Boilers 1, 2 and 3 to 1.5 % sulfur by weight, and the raising of all boiler stack heights to 65 meters (213 feet). If EPA approves the use of the non- guideline ISC Prime model for this project, all ambient air quality standards and PSD increments will have to be met.

The proposed project with the reduction of sulfur content and stack height increases will increase PM_{10}, SO_2, NOx, CO and VOC emissions at levels in excess of PSD significant amounts. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. Potential emissions increases for VOC are above the 100 TPY ambient impact analysis threshold for the pollutant ozone. The applicant presented the potential VOC emissions increases to the Department, and discussed options available to predict potential impacts associated with the emissions and formation of ozone, since no stationary point source models are available and approved for use in predicting ozone impacts. Based on the available information, the Department has determined that the use of a regional model that incorporates the complex chemical mechanisms for predicting ozone formation is not applicable to this project.

The air quality impact analyses required by the PSD regulations for this project include:

- An analysis of existing air quality for SO_2, PM_{10}, CO and VOC;
- A significant impact analysis for SO_2, PM_{10}, NO_2, CO and VOC;
- A PSD increment analysis for SO_2 and PM_{10};
- An Ambient Air Quality Standards (AAQS) analysis for PM_{10}, SO_2 and CO;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact, PSD increment, and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA and department guidelines. Good Engineering Practice (GEP) stack height means the greater of: (1) 65 m (213 ft) or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The boiler stacks will all be raised to 65 m (213 ft). These stacks will not exceed the GEP stack height regulations. However, these stacks will still be less than the corresponding GEP stack heights; therefore, the potential for building downwash to occur was considered in the modeling analysis for these stacks.

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

6.2 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. This monitoring requirement may be satisfied by using previously existing representative monitoring data, if available. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year.

The table below shows maximum project air quality impacts for comparison to these de minimis levels.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMUS LEVELS				
Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater than De Minimis (Yes/No)	De Minimis Level ($\mu g/m^3$)
SO_2	24-hr	89	Yes	13
PM_{10}	24-hr	15	Yes	10
CO	8-hr	1070	Yes	575
NO_2	Annual	0.92	No	14
VOC	Annual Emission Rate	700 TPY	Yes	100 TPY

As shown in the table NO_2 emissions are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for NO_2. However, SO_2, PM_{10}, CO, and VOC impacts from the project are predicted to be greater than the de minimis levels; therefore, the applicant is not exempt from preconstruction monitoring for these pollutants. The applicant may instead satisfy the preconstruction monitoring requirement using previously existing representative data. Previously existing representative monitoring data does exist from PM_{10} SO_2, CO and ozone monitors either in the local Clewiston area or the urbanized West Palm Beach area to the east of the project. These data are appropriate for fulfilling the monitoring requirement for these pollutants, and to establish a background concentrations for use in the PM_{10}, SO_2 and CO AAQS analyses. The background concentrations for these pollutants are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	Averaging Time	Background Concentration ($\mu g/m^3$)
PM_{10}	Annual	23
	24-hour	39
SO_2	Annual	5
	24-hour	13
	3-hour	47
CO	8-hour	3,430
	1-hour	15,441

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

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Because five years of data are used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if there are significant impacts occur from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

6.4 Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 500 receptors were placed along the facility's restricted property line and out to 35 km from the facility, which is located in a PSD Class II area. Modeling refinements were done, as needed, by using a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of one or two degrees. Fifty-one receptors were placed in the Everglades National Park (ENP) PSD Class I area. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in the vicinity of the facility or in the Class I areas. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact? (Yes/No)**	**Radius of Significant Impact (km)**
SO_2	Annual	8	1	Yes	20
	24-hr	89	5	Yes	20
	3-hr	171	25	Yes	20
PM_{10}	Annual	1.14	1	Yes	3
	24-hr	15	5	Yes	3
CO	8-hr	1,070	500	Yes	2
	1-hr	2,402	2,000	Yes	2
NO_2	Annual	0.92	1	No	----

MAXIMUM PROJECT IMPACTS IN THE ENP FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact? (Yes/No)**
SO_2	Annual	0.049	0.1	No
	24-hr	0.85	0.2	Yes
	3-hr	4.43	1.0	Yes
PM_{10}	Annual	0.005	0.2	No
	24-hr	0.20	0.3	No
NO_2	Annual	0.008	0.1	No

As shown in the tables the maximum predicted air quality impacts due to SO_2, PM_{10}, and CO emissions from the proposed project are greater than the PSD significant impact levels in the vicinity of the facility. Only SO_2 emissions are greater than the PSD Class I impact levels for the ENP. Therefore, the applicant was required to do full impact SO_2, PM_{10} and CO modeling in the vicinity of the facility, within the applicable significant impact area, to determine the impacts of the project along with all other sources in the vicinity of the facility. The significant impact area is based upon the predicted radius of significant impact. The applicant was also required to do an SO_2 PSD Class I increment analysis in the ENP.

6.5 Procedure For Performing PSD Increments And AAQS Analyses

For the PSD Class II increment and AAQS analyses, receptor grids normally are based on the size of the significant impact area for each pollutant. As shown in the previous section, the sizes of the significant impact areas for the required SO_2, PM_{10}, and CO analyses were 20, 3 and 2 km, respectively.

6.6 PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. The results of the required PSD Class II and I increment analyses presented in the table below show that all of the maximum predicted impacts are less than the allowable Class II increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment? (Yes/No)**	**Allowable Increment ($\mu g/m^3$)**
PM_{10}	Annual	0	No	17
	24-hr	21	No	31
SO_2	Annual	3	No	20
	24-hr	31	No	91
	3-hr	345	No	512

PSD CLASS I INCREMENT ANALYSIS-ENP				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment? (Yes/No)**	**Allowable Increment ($\mu g/m^3$)**
SO_2	Annual	0.33	No	2
	24-hr	4.1	No	5
	3-hr	18	No	25

6.7 <u>AAQS Analysis</u>

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum-modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or significantly contribute to a violation of any AAQS.

AMBIENT AIR QUALITY IMPACTS						
Pollutant	**Averaging Time**	**Major Sources Impact ($\mu g/m^3$)**	**Background Concentration ($\mu g/m^3$)**	**Total Impact ($\mu g/m^3$)**	**Total Impact Greater than AAQS**	**Florida AAQS ($\mu g/m^3$)**
PM_{10}	Annual	13	23	36	No	50
	24-hr	77	39	116	No	150
SO_2	Annual	39	5	44	No	60
	24-hr	220	13	233	No	260
	3-hr	612	47	659	No	1,300
CO	8-hr	6,028	3,430	9,458	No	10,000
	1-hr	14,125	5,715	19,840	No	40,000

6.8 <u>Additional Impacts Analysis</u>

Impacts On Soils, Vegetation, Wildlife, and Visibility

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

Growth-Related Air Quality Impacts

There will be no growth associated with this project because no new equipment is being installed.

7.0 CONCLUSION

Based on the technical review of the complete PSD application, reasonable assurances provided by the applicant, the preliminary BACT determination, and the conditions specified in the Draft Permit, the Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. Jeff Koerner, P.E., is the permitting engineer responsible for reviewing the application, recommending the BACT determination, and drafting the permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for this project.

Applicant's Discussion of Ambient Air Quality Impact Analysis

(Golder Associates, Inc.)

The air quality modeling analysis was initially performed using the Industrial Source Complex Short-Term (ISCST3) model, Version 98356, currently recommended for regulatory applications, to assess maximum ground-level impacts due to Boiler No. 4 and other sources at the plant. These maximum concentrations were predicted at or near the plant boundary due to building downwash conditions. The building downwash routines currently in the ISCST3 model assume that, if a stack is within the building wake region, it is treated as though it were at the center of the lee wall of the building. The wake region is assumed to extend downwind about 5 times L (5L) from the lee of the building where L is the lesser dimension of the building height or width. The location of the stack within the wake region is not considered even though the stack may be situated away from the building. The building downwash routines assume an "all-or-nothing" approach even though stacks located in the far wake region (about 3L) will be less influenced by downwash conditions than those located in the near wake region.

It should also be noted that the downwash routines in the ISCST3 model were largely developed with data that represented neutral stability, moderate-to-high windspeed, winds perpendicular to the building face, and non-buoyant or low buoyancy plumes.

Besides the lack of consideration of a stack's location within the building wake region, some of the limitations of the these downwash routines include:

- No consideration for streamline deflection to account for ascent of wind streamlines upwind of and over the building and descent in the lee of the building;
- No connection between plume material captured by the near wake and far wake concentrations;
- No wind direction effects for squat buildings; and
- Predictions of high concentrations during light windspeed, stable conditions that are not supported by observations.

Based on the sources under evaluation for this project, the associated boiler stacks at the Clewiston mill are located between 3L and 5L from the most influential buildings. Although these sources are within the wake effects of nearby buildings, the current downwash procedures assume that these stacks are essentially adjoining the buildings and the full downwash effects are used to predict maximum concentrations. Based on studies performed by the EPA (1997), the effects of building downwash within the wake region are actually reduced as a stack's location increases away from the building. In fact, wind tunnel and field studies have made it clear that incorporating the location of stacks, as well as estimates of windspeed, streamline deflection, and turbulence intensities in the wake, are crucial in improving model simulations of the influence of buildings on ground-level concentrations. As a result, the use of the building downwash routine in the ISCST3 model may not be appropriate for assessing building downwash effects for the boiler stacks at the Clewiston mill since the stack locations are not considered, are located in the far wake regions, and would not be expected to be influenced by the full downwash effects.

To provide more realistic plume behavior and resulting concentrations in the vicinity of nearby building structures, a non-regulatory version of the Industrial Source Complex Short-Term (ISCST) model was also used to assess building downwash effects. Referred to as the ISC-PRIME model, the model incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). The ISC-PRIME model (Version 99020), which has undergone extensive testing by the EPA, is currently planned as a future replacement for the current regulatory version of the ISCST3 model. It is anticipated that the model will be included as a regulatory model after EPA holds the 7th Conference on Air Quality Modeling tentatively scheduled for the spring 1999/2000. Other than for having different downwash algorithms, the ISC-PRIME and ISCST3 models are identical and use the same methods for estimating pollutant concentrations.

The ISC-PRIME model was used in the same manner as the ISCST3 model would be used in a regulatory evaluation, and followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments.

The building dimensions were considered in the air modeling analysis for the Clewiston mill. At the Clewiston mill, the five boiler stacks are in the area of influence (i.e., within 5L) of the two tallest structures: the 136-ft sugar silos and the 130-ft support structure located at the sugar refinery. The stack-to-building height ratios for the boiler stacks range from 1.1 to 1.2 and the distance of these boilers from the buildings are as follows:

	Stack Location with respect to:			
	130-ft Support Structure		136-ft Sugar Silos	
Boiler	Distance (ft)	L	Distance (ft)	L
1	505	3.9	365	2.7
2	540	4.2	405	3.0
3	592	4.6	455	3.4
4	670	5.1	545	4.0

Although these stacks are generally within the wake effects of nearby buildings, the current downwash procedures assume that these stacks are essentially adjoining the buildings and the full downwash effects are used to estimate maximum concentrations. In reality, the boiler stacks are between 3L and 5L of influence of those structures, and as such, should have a reduced effect due to building downwash from that assumed by the ISCST3 downwash routines.

The primary purpose for using the ISC-PRIME model in this modeling analysis is to incorporate more realistic assumptions and procedures in evaluating ground-level concentrations that the ISCST3 model does not consider. The following features include:

1. Enhanced plume dispersion in the region of a building's turbulent wake,
2. Reduced plume rise due to streamline deflection in the lee of a building,
3. Increased plume entrainment in the building wake,
4. Continuous plume treatment from the near field wake adjoining the building to the far wake fields away from the building, and
5. Reduced downwash effects as a plume's position increases away from the building.

For sources located away from buildings, it is important that the plume's position is tracked within the wake to account for the reduced downwash effect from buildings as a plume travels further from influence of the building.

The following table summarizes the initial analysis with ISCST3, the ISC-Prime analysis under review by EPA, and the alternate analysis (ISCST3) with the additional limiting conditions.

Pollutant and Averaging Time	(A) ISCST3 Model Existing Stacks μg / m³	(B) ISC-Prime Model Existing Stacks μg / m³	(C) ISCST3 Model Modified Stacks μg / m³	Florida Ambient Air Quality Standards μg / m³
SO2				
Annual	137	42	45	60
24-hour	928	257	239	260
3-hour	2982	959	679	1300
PM10				
Annual	55	33	36	50
24-hour	247	117	119	150
CO				
8-hour	20,778	8310	9670	10,000
10hour	53,709	15,441	20,480	40,000

(A) Based on ISCST3, an EPA-approved model. Existing stack heights for all boilers were used. Fuel oil containing 2.5% sulfur by weight was used for Boiler Nos. 1 through 4.

(B) Based on ISC-Prime, a model and analysis currently under review by the EPA Region 4 office for a case-by-case determination on this project. Existing stack heights for all boilers were used. Fuel oil containing 2.5% sulfur by weight was used for Boiler Nos. 1 through 3 and 0.7% by weight for Boiler no. 4.

(C) Based on ISCST3, an EPA-approved model. Stack heights for Boiler Nos. 1 through 4 would be raised to 213 feet. Fuel oil containing 1.5% sulfur by weight was used for Boiler Nos. 1 through 3 and 0.7% by weight for Boiler no.

DRAFT PERMIT

PERMITTEE

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

Authorized Representative:
Murray T. Brinson, Vice President

Permit No.	051-0003-009-AC
PSD No.	PSD-FL-272
Project:	Boiler No 4 and Refinery Expansion
SIC No.	2061, 2062
Expires:	(DRAFT)

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, 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

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

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 dated (DRAFT).
- Department's Intent to Issue dated (DRAFT).

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 in this permit.

4. General Conditions: The owner and operator are 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 facility owner or operator 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.]

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).

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 not to exceed 1500 gallons in any hour. 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 period nor 88,000 gallons during any consecutive 24-hour period. To comply with the fuel consumption limits, the permittee shall install, calibrate, operate, and maintain 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 may install a new, dedicated storage tank for Boiler No. 4 **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 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 conditions 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. EPA Approval of ISC Prime Model: If EPA Region 4 ***does not*** approve the air quality analysis for this project based on the ISC Prime model prior to issuance of this final permit, the permittee shall comply with the following 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 for the common tank shared by Boiler Nos. 1, 2, 3, and 4. (The permittee may install a separate tank for Boiler No. 4.)

   (b) Within 180 days after issuance of this final permit, the permittee shall submit final plans for increasing the stack heights for Boiler Nos. 1, 2, 3, and 4 to 213 feet. Modification of all stacks shall be complete with one year after issuance of this final permit.

   However, if EPA approves the use of the ISC Prime model *and* the corresponding air quality analysis for this project within 180 days of issuance of this final permit, specific conditions 7.(a) and 7.(b) shall no longer apply. The Department may revise this condition and/or other specific conditions of this permit to satisfy any changes resulting from the approval of the air quality analysis based on the ISC-Prime model. [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 250 gallons per minute, based on a 6-minute average.

   The monitoring equipment shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations. The operator shall read and record each scrubber parameter at the beginning of the shift, at least once every 4-hours, and at the end of the shift. Should any monitored parameter fall outside the specified operating range, the operator shall investigate the cause and take corrective action to regain operation within the specified range. In addition, the operator shall begin reading and recording all monitored parameters at 30-minute intervals until successive readings indicate operation within the specified range. The operator shall record any problems with operation of the wet scrubber and corrective actions taken in the Daily Operations Log required by this permit. Operation outside of the specified range for any monitored parameter is not a violation of this permit, in and of itself. However, continued operation outside of a specified 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 current 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, steam pressure, 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 30 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's consultant 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. In addition, the Department may revise *Appendix GCP* as a minor modification of this permit based on a request by the permittee or new information. [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 0.10 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".

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

   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: Annual performance tests for CO, NOx, PM/PM10, SO_2, VOC, and visible emissions shall be conducted to demonstrate compliance with the emissions standards specified in this permit. If the initial boiler thermal efficiency test indicates an efficiency of less than 50%, the permittee shall conduct an annual test. Annual tests shall be conducted at least once during each federal fiscal year (October 1st to September 30th). [Rules 62-212.400 (BACT), 62-4.070(3), and 62-297.310(7)(a)4., F.A.C.]

19. Tests Prior to Renewal: If the initial boiler thermal efficiency test indicates an efficiency of 50% or greater, the permittee shall conduct a test during the federal fiscal year (October 1st to September 30th) prior to renewal of the air operation permit or at least once during each 5-year period. [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 differential, the scrubber nozzle pressure, the scrubber water flow rate, the flue gas oxygen content, and the flue gas carbon monoxide content at 15 minute intervals. For each test run, the permittee shall monitor and record the steam production rate, steam temperature, steam pressure, feed water flow rate, feed water temperature, feed water pressure, oil flow rate, bagasse consumption rate, and the heat input. [Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

22. Daily Operations Log: To demonstrate compliance with the performance requirements of this permit, the permittee shall record the following information in a daily log.

   a. **Startup and Shutdown**: The operator shall record the time and date the boiler undergoes startup, shutdown, or malfunction. The operator 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 operator shall record the following information at the beginning of each shift, at least once every hour, and at the end of each shift: Oxygen content of flue gas and carbon monoxide content of flue gas. Alternatively, the permittee may install an automated device to continuously record these parameters.

   d. **Wet Scrubber Parameters**: The operator shall record the following information at the beginning of each shift, at least once every 4-hours, and at the end of each shift: 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 continuously record these parameters.

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

   f. **Oil Delivery**: For each fuel oil delivery, the owner of operator 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 owner or operator 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 in the Daily Operations Log.

   h. **Daily Summary**: For each day of operation, the operator 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 gallons per hour (maximum)

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. Any data indicating operation outside of permitted levels shall include corrective actions taken to regain proper operation and a comment explaining the incident. [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 and pounds per hour (24-hour avg.)
- Heat input: mmBTU per month, mmBTU per consecutive 12 months, mmBTU per hour (24-hour avg.)
- 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

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. Any data indicating operation outside the specified permit limits shall be reported to the Compliance Authorities within 10 calendar days of recording the data and shall include a written summary. [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 100,000 gallons of No. 6 fuel oil (or a superior grade) containing nor more than 0.7% sulfur by weight.

{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 3 and 4 below. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.110b(c)]

RECORD KEEPING REQUIREMENTS

3. 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)]
4. 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.	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; 20 to 30 inches of water across venturi scrubber with a 36 gpm flow rate; 3 to 5 inches of water across the tray scrubber with 230 gpm flow rate; and a 97% particulate removal efficiency.

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 very low sulfur 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 to destroy a 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. The afterburner temperature shall be maintained above 1200° F based on a 10-minute average and be continuously monitored and recorded. [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 to control at least 97% of the maximum particulate emissions from the decolorization process. The venturi scrubber shall be designed for a pressure drop of between 20 to 30 inches of water column and the wet tray scrubber shall be designed for a pressure drop of between 3 to 5 inches of water column. Separate

manometers (or equivalent devices) shall be installed, operated, and maintained to indicate the pressure drop across each control device. [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 5% opacity 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 each emission standard shall be conducted for PM/PM10, VOC, and 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 of this permit. In addition, these tests shall be performed during the federal fiscal year (October 1st to September 30th) prior to renewing the air operation permit or at least once every five years. [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 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. Operator Log: At least once per shift, the operator shall observe and record (or install automated equipment to continuously record) the afterburner temperature and the wet scrubber pressure differentials. [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.

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 operator 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 owner or operator 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 dust collector (S-4)

Note: All baghouses and dust collectors are designed for a 99.9% control efficiency.

CONTROL EQUIPMENT AND TECHNIQUES

1. Baghouses: The owner or operator shall install, operate, and maintain high efficiency baghouses to control particulate matter from each of these emissions units and points. 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 per day nor 730,000 tons per consecutive 12 months shall be packaged at this facility. In addition, no more than 2200 tons per day nor 803,000 tons 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

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

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.]

COMMON CONDITIONS FOR ALL EMISSIONS UNITS

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 owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [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 owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

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

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

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 owner or operator. [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 owner or operator 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. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but *no later than 45 days after the last sampling run of each test is completed.* The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

18. Excess Emissions Report: If excess emissions occur, the owner or operator 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. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rule 62-4.130, F.A.C.]

19. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each owner or operator 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.]

20. 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.]

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

Draft 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, NO_x, 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 an increase 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 annual 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 annual 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 Draft Permit will include 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™, 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/PM10)

Discussion of PM/PM10 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/PM10

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 Draft Permit. In addition, the Draft Permit will require 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.

Department's SAM and SO_2 BACT Determination

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. Therefore, the Department agrees with the applicant and establishes the following emission standard as BACT for firing bagasse.

"Emissions of SO_2 shall not exceed 0.10 pounds per mmBTU of heat input from bagasse as determined by EPA Methods 6, 6C, or 8."

The Draft Permit will require 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 Draft Permit will specify 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	Controls result in 98% reduction.
SO_2	0.5	2.2	Results from firing fuel in furnace and afterburner.
VOC	1.0	4.4	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 Draft Permit will include 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 5% 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 Draft Permit will include 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/PM10	Bagasse Firing, Good Combustion Practices	0.15 lb/mmBTU
	Oil Firing, Good Combustion Practices	0.10 lb/mmBTU
SO_2 (SAM)	Fuel Oil Sulfur Limit	0.7% sulfur by weight
	Bagasse Firing	0.10 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/PM10	Controlled by Afterburner and Wet Scrubbing System	0.7 lb/hr
	Surrogate PM Standard	Visible emissions < 5% 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 Draft Permit shall include 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 Draft 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 Draft 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 Draft 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:

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	*Approved By:*
(DRAFT)	(DRAFT)
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date: ______________	Date: ______________

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 and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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.

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.

3. Bagasse moisture content will be maintained at or below 55

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.

<u>NOx Controls</u>

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.

<u>Miscellaneous</u>

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.

<u>Cold Startup (approximately 4 to 5 hours)</u>

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.

{Note: Although cold startup may take as long as 5 hours, the boiler may not be in a state of excess emissions throughout this period.}

<u>Hot Startup (approximately 1 hour)</u>

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.

<u>Shutdown</u>

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: Clair Fancy

THRU: Al Linero [signature] 10/4

FROM: Jeff Koerner [initials]

DATE: October 4, 1999

SUBJECT: Draft Permit No. 051-0003-009-AC (PSD-FL-272)
U.S. Sugar Clewiston Mill
Expansion of Boiler No. 4 and Refinery Operations

Attached for approval and signature is the Draft Permit package for the U.S. Sugar Clewiston Mill and Refinery located in Hendry County. The proposed Draft Permit allows a 25% increase in heat input for Boiler No. 4, operation of Boiler No. 4 throughout the calendar year, an increase in all refinery operations to full capacity (8760 hours per year), the addition of powdered sugar and starch bins, and the addition of new sugar conditioning silos. A Best Available Control Technology (BACT) determination was required CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

The Department has determined that good combustion practices for emissions of CO, NOx, and VOC is the only viable control option at this time for the existing bagasse/oil-fired Boiler No. 4. The Draft Permit requires the installation and operation of CO and oxygen process monitors to provide feedback to the boiler operators as an indicator of the combustion efficiency. The existing wet spray impingement scrubber will control emissions of PM/PM_{10} and SO_2. The allowable fuel oil sulfur content was reduced from 1.5% to 0.7% sulfur by weight to further control emissions of SAM and SO_2 from oil firing. The decolorization process in the refinery operations includes a carbon bed to remove colorants and organics from the gas stream. Particulate matter emissions from this process are controlled by a wet venturi/tray scrubber system. Emissions of VOC from the decolorization process are controlled by a direct flame afterburner. All material handling operations are controlled by high efficiency baghouses. The maximum future potential emissions from this project in tons per year (TPY) will be: 9373 TPY of CO; 277 TPY of NOx; 252 TPY of PM; 17 TPY of SAM; 171 TPY of SO_2; and 724 TPY of VOC.

The initial application included an air quality analysis based on an air dispersion model (ISC-Prime) that has not yet been approved by the EPA. The EPA Region 4 office is currently reviewing the model and air quality analysis for a case-by-case approval. Because of the importance to the applicant in obtaining this permit prior to the new sugarcane grinding season, the applicant later submitted an alternate air quality analysis based on the EPA-approved air dispersion model (ISCST3), decreased fuel sulfur content (from 2.5% to 1.5%) for Boiler Nos. 1 through 3 not directly subject to this modification, and a proposed increase of stack heights to 213 feet (65 m) for Boiler Nos. 1 through 4. The Draft Permit contains conditions that include these additional changes should EPA Region 4 reject either the model or the air quality analysis. The alternate air quality analysis was reviewed and approved by staff meteorologist, Cleve Holladay.

I recommend your approval and signature. Day 90 of the permit time clock is December 20, 1999.

Attachments

AAL/jfk

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

ARMS Permit No.	051-0003-009-AC
PSD Permit No.	PSD-FL-272
Facility ID No.	097-0003
SIC No.	2061, 2062

PROJECT DESCRIPTION

This project included an expansion of operations at the U.S. Sugar Clewiston Sugar Mill and Refinery located in Hendry County. The proposed Draft Permit allows a 25% increase in heat input for Boiler No. 4, operation of Boiler No. 4 throughout the calendar year, an increase in all refinery operations to full capacity (8760 hours per year), the addition of powdered sugar and starch bins, and the addition of new sugar conditioning silos. A Best Available Control Technology (BACT) determination was required CO, NOx, PM/PM10, SAM, SO_2, and VOC pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

It was determined that good combustion practices for emissions of CO, NOx, and VOC is the only viable control option at this time for the existing bagasse/oil-fired Boiler No. 4. The Draft Permit requires the installation and operation of CO and oxygen process monitors to provide feedback to the boiler operators as an indicator of the combustion efficiency. The existing wet spray impingement scrubber will control emissions of PM/PM10 and SO_2. The allowable fuel oil sulfur content was reduced form 1.5% to 0.7% sulfur by weight to further control emissions of SAM and SO_2 from oil firing. The decolorization process in the refinery operations includes a carbon bed to remove colorants and organics from the gas stream. Particulate matter emissions from this process are controlled by a wet venturi/tray scrubber system. Emissions of VOC from the decolorization process are controlled by a direct flame afterburner. All material handling operations are controlled by high efficiency baghouses. The fture potential emissions from this project will be: 9373 TPY of CO; 277 TPY of NOx; 252 TPY of PM; 17 TPY of SAM; 171 TPY of SO_2; and 724 TPY of VOC.

The initial application included an air quality analysis based on an air dispersion model (ISC-Prime) that has not yet been approved by the EPA. The ISC-Prime model predicts a less conservative downwash condition associated with a new refinery building not previously modeled. The EPA Region 4 office is currently reviewing the model and air quality analysis for a case-by-case approval. Because of the importance to the applicant in obtaining this permit prior to the new sugarcane grinding season, the applicant later submitted an alternate air quality analysis based on the EPA-approved air dispersion model (ISCST3), decreased fuel sulfur content (from 2.5% to 1.5%) for Boiler Nos. 1 through 3 not directly subject to this modification, and a proposed increase of stack heights to 213 feet for Boiler Nos. 1 through 4. The Draft Permit contains conditions that include these additional changes should EPA Region 4 reject either the model or the air quality analysis. The alternate air quality analysis was reviewed and approved by staff meteorologist, Cleve Holladay. It is important to remember that problems associated with the air quality analysis are the result of conditions at the existing facility, regardless of whether or not this modification is issued.

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

Jeffery F. Koerner — 10-6-99

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

Department of Environmental Protection
Bureau of Air Regulation, New Source Review Section