C. EU 024, 025, and 026 - Fuel Tanks for Boilers

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

EU No.	Emission Unit Description
024	NSPS fuel storage tank for Boiler No. 4: Tank with a storage capacity of 100,000 gallons of No. 6 fuel oil (or a superior grade) containing no more than 0.7% sulfur by weight. Constructed in 2000.
025	Common fuel storage tank for Boiler Nos. 1 – 3: Tank with a storage capacity of 400,000 gallons of No. 6 fuel oil (or a superior grade) containing no more than 2.50% sulfur by weight. Constructed prior to 1984.
026	NSPS fuel storage tank for Boiler No. 7: Tank with a storage capacity of 200,000 gallons of No. 2 distillate oil (or a superior grade) containing no more than 2.50% sulfur by weight. Constructed in 1996.

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

RULE APPLICABILITY

The following two conditions apply only to EUs 024 and 026:

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

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

RECORD KEEPING REQUIREMENTS

3. Signs: The permittee shall clearly mark each tank with the following statements:
   a. "Tank for Boiler Nos. 1 -3: From October through April, only fuel oil containing 2.50% sulfur by weight or less may be added to and stored in this tank. From May through September, only fuel oil containing 1.60% sulfur by weight or less may be added to and stored in this tank."
   b. "Tank for Boiler No. 4: Only fuel oil containing 0.70% sulfur by weight or less may be added to and stored in this tank."
   c. "Tank for Boiler No. 7: Only distillate oil containing 0.05% sulfur by weight or less may be added to and stored in this tank."

4. Records: For EU 024 and 026, the permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(b)]

5. Record Retention: For EU 024 and 026, the permittee shall keep a copy of this record for the life of the tank. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(a)]

D. EU 017 - Granular Carbon Regenerative Furnace

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

3. Allowable Fuel: Only No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner. The fuel sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. [Applicant Request; Rule 62-212.400(BACT), F.A.C.]

CONTROL EQUIPMENT

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

5. GCRF Wet Scrubber: The permittee shall install, operate, and maintain a wet venturi / tray scrubber system designed to control at least 97% of the maximum particulate emissions during regeneration of the

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

EMISSION LIMITING STANDARDS

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

E. EU 021 - Alcohol Emissions and EU 023 - Propane-Fired Sock Heaters

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

2. Allowable Fuel: Only commercially available propane shall be fired in the sock heaters. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.]
3. Visible Emissions: Visible emissions of 5% opacity or less from the sock heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are above 5% opacity, the permittee shall investigate the cause and take the necessary corrective actions. There is no initial or periodic testing required for this condition. [Rule 62-4.070(3), F.A.C.]
4. Alcohol Emissions: Alcohol usage from the sugar refinery shall not exceed 30,000 pounds per consecutive 12 months. Compliance shall be determined by the purchase records and the Material Data Safety Sheets (MSDS) for these products. The permittee shall calculate and record the alcohol emissions for submittal of the Annual Operating Report and at the request of the Department. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

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

F. EU 015, 016, 018, 019, 020, AND 022 - MISCELLANEOUS PARTICULATE SOURCES

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

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

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

CONTROL EQUIPMENT AND TECHNIQUES

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

PERFORMANCE RESTRICTIONS

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

EMISSION LIMITING STANDARDS

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

G. 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 permittee's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [Rule 62-4.130, F.A.C.]

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

6. Excess Emissions:

   (a) Excess emissions resulting from start-up, shutdown or malfunction of any emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

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

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

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

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

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

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

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

8. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the permittee, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

9. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

10. Calculation of Emission Rate: The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

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

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

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

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

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

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

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial performance tests for NSPS sources and at least 15 days prior to any other required tests. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the permittee. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the permittee of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

16. Records: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

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

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

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

20. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each permittee shall notify the Department or the appropriate local program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department. [Rule 62-210.700(6), F.A.C.]

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

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

The following table summarizes the BACT emissions standards and control technology established in initial Permit No. PSD-FL-272.

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
	Visible Emissions	VE < 20% opacity, except 40% for 2 min./hour
SO2 (SAM)	Fuel Oil Sulfur Limit	0.7% sulfur by weight
	Bagasse Firing	0.06 lb/mmBTU
VOC	Good Combustion Practices	0.50 lb/mmBTU, as propane
EU 024 - NSPS Fuel Storage Tank for Boiler No. 4 (Record Keeping Requirements Only)		
EU 017 - Granular Carbon Regenerative Furnace with Afterburner and Wet Scrubber		
PM/PM10	Controlled by Afterburner and Wet Scrubbing System	0.7 lb/hr
	Surrogate PM Standard	Visible emissions < 10% 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	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

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

G.13 This permit incorporates the following previously issued determinations:

(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 are based upon U.S. Sugar's most recent submittal received by the Department in January of 2001.

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 (including oxygen and carbon monoxide process monitors) 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 includes instruction for observing the oxygen and carbon monoxide process monitors to promote good combustion as well as adjusting operations in response to an alarm condition. 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. Process monitors will be installed to monitor the oxygen (O_2) content and the carbon monoxide (CO) content of the boiler flue gas. The instrument readouts 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 oxygen process monitor will include an alarm with a set point at 1.5% (minimum) flue gas oxygen content based on a 1-hour block average. The CO process monitor will include an alarm with a set point at 3000 ppm (maximum) flue gas CO concentration based on a 1-hour block average. Each monitor will display both the instantaneous and the 1-hour block average. If the alarm is tripped for either process monitor (low oxygen content or high CO concentration), the boiler operator shall take corrective actions consistent with good combustion practices. Corrective actions may include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, firing some fuel oil in place of bagasse. For each such incident, the operator will summarize the corrective actions taken and the approximate time when operation within the target parameter(s) was regained.

NOx Controls

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

Miscellaneous

1. Several times per shift, the boiler grates and feeders are examined for proper distribution and any necessary operational changes are made. Any unusual observations are logged once per shift.

2. Once per day, on the day shift, the boiler will be given a walk-around inspection with the following items being checked and repaired as needed and in coordination with the production schedule: Fans, pumps, casing, ducting, and scrubber.

3. On every shift burners are inspected and cleaned if dirty.

4. On every shift, precautions will be taken as necessary to control visible emissions of fugitive matter (dust and bagasse, etc.)

STARTUP AND SHUTDOWN PROCEDURE

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

During startup and shutdown of the boilers, excess CO, PM, NOx, and VOC emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions shall be taken to minimize the magnitude and duration of excess emissions during startup and

shutdown of Boiler No. 4. The boiler room foreman and operating personnel shall receive proper training on emissions control procedures at least once per year.

Cold Startup (approximately 4 to 5 hours)

1. Feed solid fuel into boiler construction chamber.
2. Start fire in combustion chamber using a propane torch designed for that purpose.
3. As boiler heats up and starts to make steam, continuously observe the boiler and scrubber water levels, and stack plume.
4. Light a burner at the lowest rate, continue to observe the stack plume and adjust if necessary, by adjusting fuel, atomizing steam, and air to obtain proper combustion.
5. Feed carbonaceous fuel from the mill to the boiler slowly at first; as the furnace gets hotter and the carbonaceous fuel is burning better, decrease fuel oil flow until burners can be turned off.
6. Continue to observe the stack plume, the scrubber water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain the optimum operating conditions.

Hot Startup (approximately 1 hour)

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

Shutdown

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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

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

Enclosed is Final Permit No. 0510003-009-AC (PSD-FL-272). This permit authorizes U.S. Sugar Corporation to expand the operation of Boiler No. 4 and emissions units associated with refinery operation. As noted in the Final Determination (attached), minor changes to the draft permit were made by the Department, mostly at the requests of the applicant and EPA Region 4. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

Date: 11/19/99

CERTIFICATE OF SERVICE

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

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

Clerk Stamp

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

(Clerk) 11-22-99 (Date)

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

REVISIONS INITIATED By THE DEPARTMENT

Section III. EU 009 – Boiler No. 4

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

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

Section III. EU017 – GCRF

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

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

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

Section II. Administrative Permitting Requirements

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

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

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

Section III. EU 009 – Boiler No. 4

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

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

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

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

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

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

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

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

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

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

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

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

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

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

a. Request: Add text " ... as covered by Common Condition No. 6." to the requirement to record startup, shutdown and malfunction. **Response**: This text is unnecessary and the condition was not revised.

b. No changes requested.

c. Request: Delete requirement to record CO and O_2 data at the beginning of the shift and at the end of the shift and leave requirement to record data at least once every hour. **Response**: This condition was changed to require recording data once startup was complete and normal operation was established and at least once per hour during operation.

d. Request: Delete requirement to record wet scrubber data at the beginning of the shift and at the end of the shift and leave requirement to record data at least once every 4 hours. **Response**: This condition was changed to require recording data once startup was complete and normal operation was established and at least once every three hours, consistent with the previous revision for Specific Condition No. 8.

e. Request: Change rolling average to block average for oil flow rates. **Response**: The condition was revised.

f. Request: Add text "... for Boiler No. 4 ..." to oil delivery requirements. **Response**: Depending on the option selected by the permittee, Boiler No. 4 may fire fuel from a common tank. Therefore, this condition would apply to all fuel oil deliveries to the common tank. The condition was not revised.

g. Request: Delete text "... in the Daily Operations Log." From the requirement to record calibrations and repairs. **Response**: The Department views the Daily Operations Log as the combination of data recorded by the permittee to comply with the conditions of the permit. In addition, the information should be used to adjust operations to maintain compliance with operating, control, emission, and capacity requirements. "Daily Operation Log" was changed to "Daily Operational Records".

h. Request: Change "... next workday." to "... 3rd following workday ..." to allow for weekends and holidays. **Response**: These parameters are key operating and control parameters. The operating supervisor is responsible for monitoring and reviewing data as well as adjusting operations to comply with the requirements of the permit. Summarizing four key parameters should not be burdensome. The condition was not changed. **Request:** Add text "... as determined from Condition 22.e." to oil firing rate data. **Response**: This condition was revised to read "... as determined by data collected from the oil flow meter ..." **Request:** Add a list of items for which to take corrective actions to regain proper operation. **Response**: This condition was revised by adding the text, "For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any."

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

consumption, or the oil firing rates, then the permittee shall submit a written notification and summary to the Compliance Authorities within ten (10) calendar days of recording the data."

Section III. EU024. Fuel Tank

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

Section III. EU017 - GCRF

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

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

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

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

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

equipment as BACT. Failure of the compliance test should result in improved control methods, not emissions limits. The condition was not changed.

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

EU - Miscellaneous Particulate Sources

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

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

Appendix GC

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

Appendix GCP

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

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

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

BACT Determination

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

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

Air Quality Analysis

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

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

CONCLUSION

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

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:	November 22, 2000

PROJECT AND LOCATION

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

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

STATEMENT OF BASIS

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and the Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297. The above named permittee is authorized to construct and modify the emissions units in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

APPENDICES

The attached appendices are a part of this permit:

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

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 11/19/99

FACILITY DESCRIPTION

This facility consists of an existing sugar mill and refinery. Sugarcane is harvested from nearby fields and transported to the mill by train or truck. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze the juice from the cane. The cane juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The primary air pollution sources in the mill are the bagasse/oil-fired Boilers Nos. 1 through 6 with wet scrubbers for particulate matter control and the bagasse/oil-fired Boiler No. 7 with an electrostatic precipitator to control particulate matter. Air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, conditioning silos with duct collectors, vacuum systems, sugar/starch bins, conveyors, and a packaging system.

PROJECT DETAILS

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

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

REGULATORY CLASSIFICATION

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

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

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

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

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

RELEVANT DOCUMENTS

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

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

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

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

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-210, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.). The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. Operation Permit Required: This permit authorizes modification of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for and receive a Title V operation permit prior to expiration of this permit. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting and Compliance Authorities. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

This portion of the permit addresses the following emissions unit.

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

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

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

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

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

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

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

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

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

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

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

   (a) The permittee shall immediately begin purchasing No. 6 fuel oil (or a superior grade) containing no more than 0.70% sulfur by weight as replacement oil for Boiler Nos. 1, 2, 3, and 4 to be stored in the common tank currently shared by these boilers. These boilers may fire oil from the common tank, which may contain oil with a sulfur content higher than 0.7% by weight due to the oil that is currently

stored in the existing tank. As new deliveries of oil containing no more than 0.7% by weight are made, the sulfur content of this tank will gradually be reduced to 0.7% sulfur by weight or less. For each fuel oil delivery, the permittee shall record and retain the following: the date; the gallons of fuel delivered; and a fuel oil analysis, including the sulfur content (percent by weight), and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable.

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

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

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

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

CONTROL EQUIPMENT AND TECHNIQUES

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

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

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

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

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

9. Good Combustion Practices: The boiler operators shall use the Good Combustion Practices (GCPs) defined in *Appendix GCP* to minimize emissions of CO, NOx, PM/PM10 and VOC from this boiler. As a critical part of the GCPs, the permittee shall install, calibrate, operate, and maintain process monitors to indicate the oxygen and carbon monoxide content of the exhaust flue gas in the boiler furnace within 120 days after issuance of this final permit. Readouts of these process monitors shall be provided in the boiler control room. It is noted that the monitored flue gas carbon monoxide content is for the purpose of determining efficient combustion and may not be representative of the actual CO emissions from the stack.

   In addition to the initial CO compliance testing required by this permit, the permittee shall conduct CO testing in accordance with EPA Method 10 for at least 12 additional 1-hour runs. This testing shall be conducted when the boiler is firing only bagasse and the boiler may be operated below 90% of permitted capacity. The permittee shall provide a 15-day advance notice of the proposed test schedule. During each run, the operators shall observe and record the CO and O2 contents of the exhaust flue gas from the process monitors at 5-minute intervals. For each run, the operators shall monitor and record the hourly steam production rate, steam temperature, and steam pressure and calculate the bagasse consumption rate, and heat input. These additional tests shall be completed within 180 days after issuance of this final permit. A complete report summarizing the test methods, recorded parameters, boiler operation and adjustments, problems during testing, and final results shall be submitted to the Permitting and Compliance Authorities within 60 days of completing the required testing. The report shall discuss the relationship between flue gas oxygen content, flue gas carbon monoxide content, and combustion efficiency. The report shall also contain a recommendation by the permittee of an acceptable minimum flue gas oxygen content and a maximum carbon monoxide content that represents adherence to good combustion practices. Based on the test results and recommendation, the Department shall revise this condition and *Appendix GCP* to reflect additional good combustion practices and appropriate monitoring. The Department shall revise *Appendix GCP* as a minor permit amendment for this initial request. Subsequent changes to the good combustion practices shall be processed as minor permit modifications including a Public Notice. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400 (BACT), F.A.C.]

EMISSION LIMITING STANDARDS

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

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

12. PM/PM10: Particulate matter emissions shall not exceed 0.15 pounds per mmBTU of heat input from bagasse firing nor 0.10 pounds per mmBTU of heat input from oil firing based on a 3-run test average as determined by EPA Method 5. Compliance when firing both fuels shall be determined by prorating the emissions standards based on the heat input from each fuel. [Applicant Request; Rules 62-296.410(2)(b)2. and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

    All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside

of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

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

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

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

EMISSIONS UNIT 024. FUEL TANK

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

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

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

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

RULE APPLICABILITY

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

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

RECORD KEEPING REQUIREMENTS

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

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

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

EMISSIONS UNIT 017. GRANULAR CARBON REGENERATIVE FURNACE

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

3. Allowable Fuel: Only No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner. The fuel sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. [Applicant Request; Rule 62-212.400(BACT), F.A.C.]

CONTROL EQUIPMENT

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

5. GCRF Wet Scrubber: The permittee shall install, operate, and maintain a wet venturi / tray scrubber system designed to control at least 97% of the maximum particulate emissions during regeneration of the

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

EMISSION LIMITING STANDARDS

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

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

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

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

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

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

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

CONTROL EQUIPMENT AND TECHNIQUES

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

PERFORMANCE RESTRICTIONS

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

EMISSION LIMITING STANDARDS

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

EMISSION LIMITING AND PERFORMANCE STANDARDS

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

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

3. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants that cause or contribute to an objectionable odor. An objectionable odor is defined as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]

4. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department's district office and, if applicable, appropriate local program. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the permittee's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [Rule 62-4.130, F.A.C.]

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

6. Excess Emissions:

   (a) Excess emissions resulting from start-up, shutdown or malfunction of any emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

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

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

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

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

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

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

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

8. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the permittee, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

9. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

10. Calculation of Emission Rate: The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

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

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

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

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

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

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

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial performance tests for NSPS sources and at least 15 days prior to any other required tests. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the permittee. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the permittee of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

16. Records: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

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

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

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

20. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each permittee shall notify the Department or the appropriate local program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department. [Rule 62-210.700(6), F.A.C.]

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

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

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

RULE CITATIONS

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

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

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

Facility Identification (ID) Number:

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

New Permit Numbers:

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

Old Permit Numbers:

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

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

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

1.0 EXISTING FACILITY

The existing facility consists of a sugar mill and refinery. Sugarcane is harvested from nearby fields and transported to the mill by train or truck. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze the juice from the cane. The cane juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The primary air pollution sources in the mill are the bagasse/oil-fired Boilers Nos. 1 through 6 with wet scrubbers for particulate matter control and the bagasse/oil-fired Boiler No. 7 with an electrostatic precipitator to control particulate matter. Air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, propane-fired heaters, conditioning silos, screening/distribution, vacuum systems, powdered sugar/starch bins, conveyors, a packaging system, and alcohol usage.

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

2.0 PROJECT DESCRIPTION

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

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

3.0 PSD APPLICABILITY REVIEW

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

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

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

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

Pollutant	Project Potential Net Emissions[a] Increase (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	4075	100	Yes	Yes
NOx	292	40	Yes	Yes
PM/PM10	116 / 108	25 / 15	Yes	Yes
SAM	7.6	7	Yes	Yes
SO2	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/PM10, SAM, SO2, and VOC emissions.

4.0 BACT DETERMINATION PROCEDURE

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

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

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

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

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

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

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

5.0 BACT DETERMINATIONS FOR BOILER NO. 4

5.1 CARBON MONOXIDE (CO)

Discussion of CO Emissions

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

Applicant's Proposed CO BACT

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

Department's CO BACT Determination

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

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

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

As indicated in several other projects for bagasse boilers, the Department is aware of five possible control methods for reducing CO emissions: Good combustion design, direct flame oxidation, catalytic oxidation, flue gas recirculation, and good combustion practices. According to the Department's ARMS

database, CO emission limits range from 0.70 lb/mmBTU to approximately 7.0 lb/mmBTU for bagasse boilers. The following is a summary of the feasibility of these methods.

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

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

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

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

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

At this time, the Department is unable to identify any practical add-on control options for the reduction of CO emissions. Therefore, the Department will adopt the "good operating practices" (GCPs) identified in the O&M Plan for Boiler No. 4 dated January 9, 1997. In addition, the Department will also require boiler efficiency testing and exhaust gas process monitors for CO and oxygen. The boiler efficiency is a critical indicator of performance as well as maintenance. This test will be used to demonstrate that the boiler is being adequately maintained at an efficiency of 55% or greater. The oxygen process monitor will serve as an indicator of the excess air being supplied and the CO

process monitor will provide an overall indicator of good combustion. The permit includes several CO emissions tests to correlate operations and emissions with the process monitors. The purpose of the process monitors is to provide the boiler operators with additional information in order to maintain control of the bagasse combustion process. This is critical because the determination of Best Available Control Technology for both CO and VOC emissions rely on the GCPs. Based on good combustion practices, the Department establishes the following emission standard as BACT.

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

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

5.2 NITROGEN OXIDES (NOx)

Discussion of NOx Emissions

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

Applicant's Proposed NOx Controls

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

Department's NOx BACT Determination

The Department is aware of the following NOx control technologies.

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

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

There are other emerging NOx controls such as Non-Selective Catalytic Reduction (NSCR) and SCONOx™, 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/PM10 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 PM10 emissions. Compliance with these standards shall be determined by the 3-run test average obtained by conducting EPA Method 5 and the performance test requirements specified in the permit. In addition, the permit requires monitoring of the scrubber liquid flow rate, the scrubber pressure drop, and the spray nozzle pressure. This limit is below the Department's existing rule for carbonaceous fuel burning equipment.

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

Discussion of SAM and SO_2 Emissions

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

Applicant's Proposed SAM and SO_2 BACT

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

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

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

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. The applicant later requested a lower limit of 0.06 lb/mmBTU. Therefore, the Department establishes the following emission standard as BACT for firing bagasse.

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

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

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

5.5 VOLATILE ORGANIC COMPOUNDS

Discussion of VOC Emissions

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

Applicant's Proposed VOC BACT

The applicant did not identify any add-on control options that were technically feasible for the control of VOC emissions from a bagasse boiler. Initially, the applicant requested BACT to be "good combustion practices" with a VOC emission standard of 1.5 pounds per mmBTU, which the applicant accepted a

lower RACT standard for major carbonaceous fuel fired boilers located in nonattainment areas in order to reduce Title V fees. The primary reason was due to a lack of data specific to Boiler No. 4. However, the submittal dated August 30, 1999, requests a lower limit of 0.5 lb/mmBTU based on other industry tests for similar bagasse boilers.

Department's VOC BACT Determination

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

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

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

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

6.0 BACT DETERMINATION FOR REFINERY OPERATIONS

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

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

6.1 BACT FOR THE GRANULAR CARBON REGENERATIVE FURNACE (GCRF)

Discussion

Part of the sugar refining process involves decolorization, which uses granular carbon to remove colorants and organics. A distillate oil-fired furnace is used to regenerate the carbon for reuse. This

drives off the colorants and organics. To control PM and VOC emissions, U.S. Sugar installed a distillate oil fired afterburner followed by a wet scrubbing system consisting of a wet venturi scrubber and wet tray or plate scrubber.

Applicant's Proposed BACT

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

Pollutant	lb/hr	TPY	Comments
CO	3.0	13.1	Results from firing fuel in furnace and afterburner.
NOx	3.0	13.1	Results from firing fuel in furnace and afterburner.
PM/PM10	0.7	3.1	From sugar processing; controls result in 98% reduction.
SO_2	0.5	2.2	Results from firing fuel in furnace and afterburner.
VOC	1.0	4.4	From sugar processing; controls result in 92% reduction.

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

Department's BACT Determination

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

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

6.2 BACT FOR THE SOCK DRYERS

Discussion

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

Applicant's Proposed BACT

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

Department's BACT Determination

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

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

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

6.3 BACT FOR THE MATERIAL HANDLING SOURCES

Discussion

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

Applicant's Proposed BACT

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

Department's BACT Determination

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

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

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

6.4 BACT FOR ALCOHOL USAGE

Discussion

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

Applicant's Proposed BACT

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

Department's BACT Determination

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

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

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

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

Pollutant	Controls	Emission Standard
EU 009 – Bagasse Boiler No.4		
CO	Good Combustion Practices	6.5 lb/mmBTU
NOx	Bagasse Firing, Good Combustion Practices	0.20 lb/mmBTU
PM/PM10	Bagasse Firing, Good Combustion Practices	0.15 lb/mmBTU
	Oil Firing, Good Combustion Practices	0.10 lb/mmBTU
	Visible Emissions	VE < 20% opacity, except 40% for 2 min./hour
SO2 (SAM)	Fuel Oil Sulfur Limit	0.7% sulfur by weight
	Bagasse Firing	0.06 lb/mmBTU
VOC	Good Combustion Practices	0.50 lb/mmBTU, as propane
EU 024 - NSPS Fuel Storage Tank for Boiler No. 4 (Record Keeping Requirements Only)		
EU 017 - Granular Carbon Regenerative Furnace with Afterburner and Wet Scrubber		
PM/PM10	Controlled by Afterburner and Wet Scrubbing System	0.7 lb/hr
	Surrogate PM Standard	Visible emissions < 10% 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	Commercially Available Propane
	Work Practice Standard for Good Combustion	Visible Emissions < 5% opacity
EU 021 – Alcohol Usage		
VOC	Alcohol Usage Limit	< 30,000 pounds per 12 months
EUs 015,016, 018, 019, 020, and 022 – Miscellaneous Particulate Sources		
PM	Surrogate Standard	Visible Emissions < 5% opacity

7.2 BACT EXCESS EMISSIONS ALLOWED

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

> *Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction of the combustion turbine shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. In no case shall excess emissions from startup, shutdown, and malfunction exceed two hours in any 24-hour period. If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. [Rule 62-210.700(1) and (6), F.A.C.]*
>
> *Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. [Rule 62-210.700(4), F.A.C.]*

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

8.0 COMMENTS FROM NPS AND EPA REGION 4

8.1 NPS COMMENTS

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

8.2 EPA REGION 4 COMMENTS

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

9.0 RECOMMENDATION AND APPROVAL

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

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

Recommended By:

, P.E.

for C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Date: 11/19/99

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management
Date: 11/19/99

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

(b) Determination of Prevention of Significant Deterioration (X); and

(c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

GOOD COMBUSTION PRACTICES

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

Purpose of GCP Plan

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

Preparation for Operations

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

Boiler Operation and Controls

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

CO and VOC Controls

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

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

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

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

NOx Controls

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

Miscellaneous

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

STARTUP AND SHUTDOWN PROCEDURE

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

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

Cold Startup (approximately 4 to 5 hours)

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

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

Hot Startup (approximately 1 hour)

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

Shutdown

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

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: November 19, 1999

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

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

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

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

Initially, the applicant submitted an air quality analysis based on a non-guideline model (ISC Prime), which requires approval of EPA Region 4. This was done because of modeled problems with CO, PM, and SO2 related to potential downwash from a recently constructed building. During the application process, it became apparent that EPA may require several months before approval could be granted. U.S. Sugar needed the permit modification early in the upcoming sugarcane season to avoid noncompliance with restrictions on operation resulting from extended operation last year. So the applicant submitted an "interim" air quality analysis based on the standard guideline model (ISCST3), reduced fuel sulfur content in other boilers at the facility, and increased stack heights. The Department based its intent to issue the Draft Permit on this analysis in an effort to begin steps toward resolving the modeled potential problems with CO, PM, and SO2. After discussing this with EPA Region 4, the final permit was revised to require U.S. Sugar to modify this permit based on the final modeling analysis. Prior to the modification, U.S. Sugar would continue to fire low sulfur fuel oil in Boilers 1 through 4 and complete construction of the increased stack heights within a year.

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

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

Attachments

CHF/AAL/jfk

Golder Associates Inc.

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

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Golder Associates

November 17, 1999

9937515A/7

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention : Jeffery Koerner, P.E.

RE: United States Sugar Corporation (U.S. Sugar) – PSD Permit Application for Boiler No. 4 and the Sugar Refinery at the Clewiston Mill
Updated ISC-PRIME Modeling Information

Dear Mr. Koerner:

The purpose of this letter is to address the issues raised by the U.S. EPA in their November 12, 1999, letter regarding the draft Boiler No. 4 PSD permit. The EPA comments are addressed below, in the same order as they appear in the comment letter.

Operational and Emission Limits

1. The current Boiler No. 4 permit restricts the annual fuel oil usage to 500,000 gal/yr, and this same cap was proposed in the permit application for the Boiler No. 4 modification. However, the draft permit did not contain such a condition. To resolve this issue, please add this limitation to the permit (i.e., in Condition 6 under the Boiler No. 4 emission unit section). Also, for modeling purposes for SO_2, it was assumed that Boiler No. 4 was operating at 633MMBtu/hr for the 3-hour averaging time, and at 600 MMBtu/hr for the 24-hour and annual averaging times, which are higher maximum heat inputs than would actually occur under combination bagasse/oil firing. This was done to be conservative, but also because for the 24-hour and annual averaging times, the worst case mill scenario is Boiler No. 4 burning 100 percent bagasse (see discussion below). Boiler No. 4 was modeled for 8,760 hr/yr in all modeling scenarios, since it is proposed to not restrict Boiler No. 4 operation to the crop season (i.e., it can operate any time during the year).
2. No comment.
3. Based on the available SO_2 test data, U.S. Sugar is willing to lower the proposed SO_2 limit for bagasse firing to 0.06 lb/MMBtu in order to resolve this issue. This is about 4 times the highest test data result, but concerns remain over meeting any lower limit on a continuous basis based on the limited test data available, and the ability of measurement methodologies to accurately measure a this low level.

Air Quality Impact Assessment

1. It is agreed that the ISC-PRIME model should provide the basis for the final permit issuance.
2. Based upon the recent approval by EPA of the ISC-PRIME dispersion model for the Clewiston mill, Golder Associates has performed additional modeling analysis in order to bring the project impacts up to date. All model runs have been re-executed using the ISC-PRIME model. In addition, U.S. Sugar seeks the option to raise the existing stacks on Boiler Nos. 1, 2 and 3 from the current 165 feet to a minimum height of 182 feet. This is being done to allow the option of burning the currently permitted 2.5% sulfur (maximum) No. 6 fuel oil in these three boilers. As a result, two sets of model impact results are being provided:
   1) Existing stack heights (Boiler Nos. 1, 2, and 3 @ 165 feet, Boiler No. 4 @ 150 feet, and Boiler No. 7 @ 225 feet), and
   2) Future stack heights (Boiler Nos. 1, 2 and 3 @ 182 feet, Boiler No. 4 @ 150 feet, and Boiler No. 7 @ 225 feet.

   PM and CO emissions are not affected by fuel oil burning since maximum emissions occur under 100 percent bagasse firing in all boilers. Therefore, the emissions for these pollutants are the same for both stack height scenarios, and have not changed from that presented in the application.

   The maximum mill SO_2 emissions and fuel usage scenario are dictated by the stack height scenario. For the 165 foot stack scenario, Boiler Nos. 1, 2 and 3 will be restricted to burning fuel oil with no greater than 2.0% sulfur in order to comply with all standards and increments. For the 182 foot stack scenario, Boiler Nos. 1, 2 and 3 will be restricted to burning fuel oil with no greater than 2.5% sulfur. The SO_2 emissions for these two scenarios are presented in Tables A and B attached.

   A shown in the attached tables, compliance with all standards and increments is predicted with the ISC-PRIME model. The 182 foot scenario tables have a "R1" reference in the table number, while the 165 foot scenario has "R2" in the table number.

   The above discussion and modeling results assume that Boiler No. 4 has a separate fuel oil tank for 0.7% sulfur fuel oil, and Boiler Nos. 1, 2, and 3 have a common tank with either 2.0% sulfur or 2.5% sulfur fuel oil. However, until such time that U.S. Sugar constructs a separate fuel oil tank for Boiler No. 4, U.S. Sugar will purchase only 0.7% sulfur fuel for the common tank. Total SO_2 emissions based on 0.7% sulfur fuel oil for Boiler Nos. 1 through 4 will be much less than either of the modeling scenarios presented above with 2.0% or 2.5% fuel oil. As a result, the modeling analysis demonstrates compliance with standards and increments for the scenario of 0.7% sulfur fuel oil being burned in all boilers.

   All model input and output files have been placed on Golder's FTP site for access by FDEP and EPA at ftp.golder.com/gville/srm/cleve/USSCLEW.

Please note that U.S. Sugar started purchasing solely 0.7% (maximum) sulfur fuel oil for the common fuel oil tank prior to the beginning of the crop season, and will continue to purchase this fuel for the common tank until such time as a separate fuel oil tank is constructed for Boiler No. 4.

Thank you for consideration of these comments. Please call or e-mail me if you have any additional questions.

Sincerely,

Golder Associates Inc.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/arz

Attachments

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
National Park Service

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CC: J. Koerner, BAR
SD
EPA
NPS

Table A. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation:
(09/20/99)

Boilers 1-3 @ 2.5% sulfur fuel oil; 182 ft stack height
Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
3	342.0 [c]	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	633.0	225.1	1,500	213.0	420.0	58,333	153.3	42.0 [d]	195.3	24.61
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	798.0	1,980.2	275,028	1,752.3	232.0	1,984.3	250.0
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
2	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
3	342.0	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	600.0	225.1	0	0.0	600.0	83,333	0.0	60.0 [d]	60.0	7.56
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,517.0	239.5	1,756.5	221.3

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions, i.e., Boiler Nos. 1, 2 and 3 burning 2.5% sulfur oil, and Boiler No.4 burning 0.7% sulfur oil. Boiler Nos. 1, 2 and 3 have 182 ft stacks, and Boiler No. 4 has a 150 ft stack.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 2.5% sulfur
18,300 Btu/lb; 150,000 Btu/gal
2.5% ≈ 8.2 lb/gal
0.7% sulfur
19,450 Btu/lb; 142,000 Btu/gal
7.3 lb/gal
Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

Table B. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation:
(11/12/99)

Boilers 1-3 @ 2.0% sulfur fuel oil; 165 ft stack height
Boiler 4 @ 0.7% sulfur; 150 ft stack height

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	492.0	18.8	510.8	64.36
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	492.0	18.8	510.8	64.36
3	342.0 [c]	135.1	900	135.0	207.0	28,750	295.2	14.4	309.6	39.01
4	633.0	225.1	1,500	213.0	420.0	58,333	153.3	42.0 [d]	195.3	24.61
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	798.0	1,980.2	275,028	1,432.5	232.0	1,664.5	209.7
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,400	210.0	285.6	39,667	459.2	19.8	479.0	60.36
2	495.6	225.1	1,400	210.0	285.6	39,667	459.2	19.8	479.0	60.36
3	342.0	135.1	900	135.0	207.0	28,750	295.2	14.4	309.6	39.01
4	600.0	225.1	0	0.0	600.0	83,333	0.0	60.0 [d]	60.0	7.56
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,213.6	239.5	1,453.1	183.1

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions, i.e., Boiler Nos. 1, 2 and 3 burning 2.0% sulfur oil, and Boiler No.4 burning 0.7% sulfur oil. Boiler Nos. 1, 2 and 3 have 165 ft stacks, and Boiler No. 4 has a 150 ft stack.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 2.0% sulfur
18,300 Btu/lb; 150,000 Btu/gal
2.5% ≤ 8.2 lb/gal

0.7% sulfur
19,450 Btu/lb; 142,000 Btu/gal
7.3 lb/gal

Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

Table 6-16R. Maximum Predicted Pollutant Impacts From Proposed Project
Screening Analysis - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	1.75	300	1500	87123124
	1.59	270	1500	88123124
	1.88	310	1500	89123124
	2.08	300	1500	90123124
	1.99	300	1500	91123124
High 24-Hour				
	27.9	240	900	87110124
	25.7	260	1200	88013024
	18.4	310	1500	89040424
	25.3	240	900	90042024
	24.0	290	1200	91052124
High 3-Hour				
	77	10	463	87011915
	92	360	456	88112306
	65	350	900	89022118
	60	240	900	90100812
	69	10	463	91030309
PM10				
Annual				
	0.80	120	675	87123124
	0.86	110	906	88123124
	0.81	310	1200	89123124
	0.79	300	1200	90123124
	0.86	300	1200	91123124
High 24-Hour				
	8.4	230	1200	87102324
	7.9	60	912	88041224
	8.0	310	1500	89040424
	11.5	240	900	90042024
	10.2	290	1200	91052124
NOx				
Annual				
	0.71	300	1500	87123124
	0.62	270	1500	88123124
	0.75	310	1500	89123124
	0.82	300	1500	90123124
	0.81	300	1500	91123124
CO				
High 8-Hour				
	1065	50	709	87062716
	891	350	600	88041816
	707	340	900	89060816
	795	240	900	90100816
	866	350	900	91042316
High 1-Hour				
	2097	350	1200	87071916
	2208	10	463	88090511
	2200	10	463	89062816
	1966	10	463	90071311
	1862	360	600	91080111

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

Table 6-17R. Maximum Predicted Pollutant Impacts From Proposed Project for Comparison to EPA Significant Impact Levels - Refined Analyses - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (μmg/m^3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	EPA Significant Impact Levels (μg/m^3)
SO_2					
Annual	2.1	302	1500	90123124	1
	2.0	300	1500	91123124	
High 24-Hour	28.3	240	800	87110124	5
	25.9	260	1100	88013024	
	32.6	244	1000	90042024	
High 3-Hour	92	360	456	88112306	25
PM10					
Annual	1.54	100	800	88123124	1
	0.86	302	1200	91123124	
High 24-Hour	13.8	244	1000	90042024	5
	11.1	292	1100	91052124	
NOx					
Annual	0.75	306	1500	89123124	1
	0.82	300	1500	90123124	
	0.81	300	1500	91123124	
CO					
High 8-Hour	1,065	50	709	87062716	500
High 1-Hour	2,134	350	1100	87071916	2000
	2,200	10	463	89062816	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Note: The project's significant impact distances (km) are SO2 - 12; PM10 - 4; CO - 3; NOx = Not significant

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

EPA = Environmental Protection Agency

Table 6-18R. Maximum Predicted Pollutant Impacts From Proposed Project at the Everglades National Park PSD Class I Area - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (ug/m^3)	UTM Receptor Location[b] (m)	(m)	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Levels (ug/m^3)
SO_2					
Annual					
	0.022	550300	2848600	87123124	0.1
	0.031	550300	2848600	88123124	
	0.031	545000	2848600	89123124	
	0.022	550300	2848600	90123124	
	0.027	545000	2848600	91123124	
High 24-Hour					
	0.49	540000	2848600	87021224	0.2
	0.50	535000	2848600	88071824	
	0.45	525000	2848600	89022824	
	0.67	545000	2844000	90082724	
	0.68	473500	2860000	91101924	
High 3-Hour					
	2.3	483000	2848500	87090706	1.0
	3.6	540000	2848600	88040603	
	3.6	525000	2848600	89022806	
	3.6	540000	2844000	90112603	
	2.9	545000	2848600	91012306	
PM10					
Annual					
	0.006	550300	2848600	87123124	0.2
	0.008	550300	2848600	88123124	
	0.008	545000	2848600	89123124	
	0.006	550300	2848600	90123124	
	0.006	550300	2848600	91123124	
High 24-Hour					
	0.18	545000	2829000	87050724	0.3
	0.22	535000	2848600	88071824	
	0.19	545000	2848600	89041924	
	0.31	545000	2844000	90082724	
	0.30	473500	2857000	91101924	
NOx					
Annual					
	0.009	550300	2848600	87123124	0.1
	0.012	550300	2848600	88123124	
	0.012	545000	2848600	89123124	
	0.009	550300	2848600	90123124	
	0.010	545000	2848600	91123124	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Universal Mercator Transverse coordinate system

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

PSD = Prevention of Significant Deterioration

NPS = National Park Service

EPA = Environmental Protection Agency

Table 6-18AR. Maximum Predicted 24-Hour PM10 Pollutant Impacts From Proposed Project at the Everglades National Park
PSD Class I Area - Refinement - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (mg/m^3)	Receptor Location[b] X (km)	Receptor Location[b] Y (km)	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Level (mg/m^3)
High 24-Hour					
	0.168	62.92	-80.54	87112924	0.3
	0.169	60.07	-82.68	88011224	
	0.171	-84.73	-57.15	89080224	
	0.154	44.80	-91.86	90121324	
	0.165	-82.68	60.07	91040824	

[a] Concentrations are highest predicted with CALPUFF model and 5-year meteorological record from W. Palm Beach, 1987-91

[b] Receptors are relative to the Clewiston Mill and are located on a circle of 102 km radius, and spaced at 2-degrees intervals

Legend:
YYMMDDHH = Year, Month, Day, Hour Ending
PSD = Prevention of Significant Deterioration
NPS = National Park Service
EPA = Environmental Protection Agency

Table 6-19R1. Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analyses - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	29.9	310	1200	87123124
	31.1	270	1200	88123124
	33.9	310	1200	89123124
	35.8	310	1200	90123124
	33.2	300	1200	91123124
H2H 24-Hour				
	231	310	1200	87080724
	240	310	1200	88040324
	217	320	900	89061524
	208	320	900	90031624
	203	320	1200	91041624
H2H 3-Hour				
	552	310	900	87080715
	615	310	900	88090912
	574	310	900	89061212
	561	270	900	90092115
	728	310	900	91070615
PM_{10}				
Annual				
	5.5	310	1200	87123124
	5.7	270	1200	88123124
	6.4	310	1200	89123124
	6.8	310	1200	90123124
	6.3	300	1200	91123124
H2H 24-Hour				
	48.7	270	1200	87123124
	49.0	310	1500	88112024
	45.2	320	900	89060424
	43.9	320	1200	90020324
	44.3	290	1200	91050924
CO				
H2H 8-Hour				
	3781	310	900	87061416
	3824	280	1200	88032408
	3978	320	900	89060516
	3323	320	1200	90031508
	4211	310	900	91043016
H2H 1-Hour				
	7822	340	900	87072410
	7798	320	900	88040612
	7930	320	900	89051714
	8872	330	527	90080511
	9124	40	600	91081212

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20R1. Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration (mg/m^3)			Receptor Location[b]		Time Period	Florida AAQS
	Total	Modeled	Background	Direction (degree)	Distance (m)	(YYMMDDHH)	(mg/m^3)
SO_2							
Annual	39.7	34.7	5	316	1100	89123124	60
	40.9	35.9	5	310	1100	90123124	
	38.2	33.2	5	300	1200	91123124	
H2H 24-Hour	258	245	13	316	1100	87032424	260
	253	240	13	310	1200	88040324	
H2H 3-Hour	775	728	47	310	900	91070615	1300
PM_{10}							
Annual	29.6	6.6	23	316	1100	89123124	50
	29.8	6.8	23	310	1100	90123124	
H2H 24-Hour	90	51	39	272	1100	87123124	150
	88	49	39	310	1500	88112024	
CO							
H2H 8-Hour	7761	4331	3430	318	900	89060416	10000
	7681	4251	3430	310	800	91043016	
H2H 1-Hour	14839	9124	5715	40	600	91081212	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-21R1. Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (mg/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	0.1	250	11000	87123124
	0.0	0	0	88123124
	0.0	0	0	89123124
	0.1	210	11000	90123124
	0.0	0	0	91123124
H2H 24-Hour				
	7	30	11000	87030524
	9	350	11000	88060224
	12	80	11000	89040224
	11	100	11000	90042124
	8	50	11000	91040824
H2H 3-Hour				
	29	60	11000	87041324
	46	60	11000	88040521
	48	70	11000	89041303
	33	120	11000	90042203
	36	80	11000	91041121
PM_{10}				
Annual				
	<0	0	0	87123124
	<0	0	0	88123124
	<0	0	0	89123124
	<0	0	0	90123124
	<0	0	0	91123124
H2H 24-Hour				
	4.9	320	900	87100624
	6.4	330	900	88062824
	5.9	350	900	89073024
	5.4	310	900	90082924
	6.0	310	900	91083124

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-22R1. Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment ($\mu g/m^3$)
		Direction (degree)	Distance (m)		
SO_2					
Annual	0.1	250	11000	87123124	20
H2H 24-Hour	12.2	78	11000	89042324	91
H2H 3-Hour	47.7	70	11000	89041303	512
PM_{10}					
Annual	<0	0	0	0	17
H2H 24-Hour	7.6	332	1200	88081424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

Table 6-23R1. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (ug/m^3)
Annual					
	0.16	550300	2848600	87123124	2
	0.14	535000	2848600	88123124	
	0.10	540000	2848600	89123124	
	0.20	545000	2848600	90123124	
	0.09	540000	2848600	91123124	
H2H 24-Hour					
	2.3	550300	2848600	87052924	5
	3.0	545000	2848600	88060224	
	2.8	545000	2848600	89040124	
	3.2	530000	2848600	90041224	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.5	530000	2848600	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
H2H = Highest, 2nd-Highest

Table 6-19R2. Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	28.9	310	900	87123124
	30.6	270	900	88123124
	32.8	320	900	89123124
	35.0	270	900	90123124
	31.9	300	1200	91123124
H2H 24-Hour				
	224	310	1200	87080724
	231	310	1200	88040324
	214	320	900	89061524
	209	320	900	90031624
	198	320	900	91041624
H2H 3-Hour				
	528	310	900	87041418
	594	310	900	88090912
	530	310	900	89061212
	507	310	900	90122224
	655	310	900	91072412
PM_{10}				
Annual				
	6.3	310	900	87123124
	6.7	270	900	88123124
	7.2	320	900	89123124
	7.8	270	900	90123124
	7.1	300	1200	91123124
H2H 24-Hour				
	59	270	900	87123124
	56	310	1200	88112024
	53	320	900	89060424
	55	250	900	90042024
	57	260	1200	91102424
CO				
H2H 8-Hour				
	4,182	310	900	87061416
	4,501	280	1200	88032408
	4,388	310	900	89041416
	4,240	250	900	90022708
	4,741	310	900	91043016
H2H 1-Hour				
	8,531	320	600	87090213
	8,681	320	600	88090413
	8,908	320	600	89061511
	9,229	330	527	90080511
	9,723	40	595	91061812

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20R2. Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration ($\mu g/m^3$)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
	Total	Modeled	Background	Direction (degree)	Distance (m)		
SO_2							
Annual	38.7	33.7	5	316	1000	89123124	60
	40.3	35.3	5	272	1000	90123124	
	37.1	32.1	5	300	1100	91123124	
H2H 24-Hour	255	242	13	316	1000	87032424	260
	246	233	13	310	1000	88040324	
H2H 3-Hour	708	661	47	310	800	91070615	1300
PM_{10}							
Annual	30.8	7.8	23	272	1000	90123124	50
H2H 24-Hour	101	62	39	272	1000	87123124	150
	98	59	39	322	1000	88112624	
	96	57	39	260	1100	91102424	
CO							
H2H 8-Hour	7,962	4,532	3,430	280	1100	88032408	10000
	8,310	4,880	3,430	312	700	91043016	
H2H 1-Hour	15,438	9,723	5,715	40	595	91061812	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-21R2. Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	0.17	250	11000	87123124
	0.03	220	11000	88123124
	0.00	0	0	89123124
	0.18	210	11000	90123124
	0.04	210	11000	91123124
H2H 24-Hour				
	6.8	30	11000	87030524
	9.0	350	11000	88060224
	11.7	80	11000	89040224
	10.7	100	11000	90042124
	8.4	50	11000	91040824
H2H 3-Hour				
	29	60	11000	87041324
	46	60	11000	88040521
	48	70	11000	89041303
	33	120	11000	90042203
	36	80	11000	91041121
PM_{10}				
Annual				
	<0	0	0	87123124
	0.04	340	1200	88123124
	<0	0	0	89123124
	0.06	330	1500	90123124
	0.04	340	1200	91123124
H2H 24-Hour				
	6.5	360	1200	87071924
	8.6	330	900	88062824
	7.3	320	900	89071224
	7.7	310	900	90082724
	10.4	310	900	91072424

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-22R2. Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment (ug/m^3)
		Direction (degree)	Distance (m)		
SO_2					
Annual	0.2	210	11000	90123124	20
H2H 24-Hour	12.2	78	11000	89042324	91
H2H 3-Hour	46.9	64	11000	88042924	512
	47.7	70	11000	89041303	
PM_{10}					
Annual	0.07	322	1500	90123124	17
H2H 24-Hour	11.5	308	900	91072424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

Table 6-23R2. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (ug/m^3)
Annual					
	0.18	550300	2848600	87123124	2
	0.16	535000	2848600	88123124	
	0.12	550300	2848600	89123124	
	0.22	545000	2848600	90123124	
	0.11	535000	2848600	91123124	
H2H 24-Hour					
	2.3	550300	2848600	87052924	5
	3.0	545000	2848600	88060224	
	2.8	545000	2848600	89040124	
	3.2	530000	2848600	90041224	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.5	530000	2848600	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
H2H = Highest, 2nd-Highest

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Murray J. Burson
US Sugar Corp
111 Ponce De Leon Ave
Clewiston, Fl
33440

4a. Article Number
Z 031 392 013

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
10-8-99 BJC

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Andrea Solis

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

Z 031 392 013

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Burson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 10-6-99	

PS Form **3800,** April 1995

05100003-009-AC
PSO-FI-272

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.

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.

Kuri Jaber (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 ($\mu g/m^3$)		Allowable Increment ($\mu g/m^3$)	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:

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PSD Class I Increment Consumed ($\mu g/m^3$)		Allowable Increment ($\mu g/m^3$)	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.

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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.

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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/PM10	116 / 108	25/15	Yes	Yes
SAM	7.6	7	Yes	Yes
SO2	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/PM10, SAM and SO2, 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/PM10, SAM, SO2 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. EPA Approval of ISC Prime Model: 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 Introduction

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 AAQS Analysis

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 Additional Impacts Analysis

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 $\mu g / m^3$	(B) ISC-Prime Model Existing Stacks $\mu g / m^3$	(C) ISCST3 Model Modified Stacks $\mu g / m^3$	Florida Ambient Air Quality Standards $\mu g / m^3$
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/PM10 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/PM10: 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)]

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.]

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

EMISSION LIMITING AND PERFORMANCE STANDARDS

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

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

3. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants that cause or contribute to an objectionable odor. An objectionable odor is defined as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]

4. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department's district office and, if applicable, appropriate local program. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the 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/PM10	116 / 108	25 / 15	Yes	Yes
SAM	7.6	7	Yes	Yes
SO2	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/PM10, SAM, SO2, and VOC emissions.

4.0 BACT DETERMINATION PROCEDURE

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

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

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

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

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

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

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

5.0 BACT DETERMINATIONS FOR BOILER NO. 4

5.1 CARBON MONOXIDE (CO)

Discussion of CO Emissions

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

Applicant's Proposed CO BACT

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

Department's CO BACT Determination

The increase in operation of Boiler No. 4 will result in 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/PM10 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 PM10 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/PM10	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
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	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:

(DRAFT)

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

Date: _____

Approved By:

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

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.

NOx Controls

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

Miscellaneous

1. Several times per shift, the boiler grates and feeders are examined for proper distribution and any necessary operational changes are made. Any unusual observations are logged once per shift.

2. Once per day, on the day shift, the boiler will be given a walk-around inspection with the following items being checked and repaired as needed and in coordination with the production schedule: Fans, pumps, casing, ducting, and scrubber.

3. On every shift burners are inspected and cleaned if dirty.

4. On every shift, precautions will be taken as necessary to control visible emissions of fugitive matter (dust and bagasse, etc.)

STARTUP AND SHUTDOWN PROCEDURE

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

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

Cold Startup (approximately 4 to 5 hours)

1. Feed solid fuel into boiler construction chamber.

2. Start fire in combustion chamber using a propane torch designed for that purpose.

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

{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.}

Hot Startup (approximately 1 hour)

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

Shutdown

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

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero

FROM: Jeff Koerner

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/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).

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/PM10 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

Jeb Bush
Governor

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

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, P.E.
Registration Number: 49441
Department of Environmental Protection
Bureau of Air Regulation, New Source Review Section

10-6-99
Date

STATE OF FLORIDA PROFESSIONAL ENGINEER

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 15, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

William A. Raiola, Vice President
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: United States Sugar Corporation – Clewiston Sugar Mill and Refinery
Extension of Air Construction Permit Expiration Date
Original Project No. 0510003-010-AC
Air Permit No. PSD-FL-272A

Dear Mr. Raiola:

On March 8, 2002, U.S. Sugar Corporation requested an extension of the expiration date of air construction Permit No. PSD-FL-272A for the Clewiston Sugar Mill and Refinery located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Specifically, the request asks for additional time to construct sugar conditioning silos and powdered sugar/starch bins, which have been delayed due to market conditions. The units are identified as minor sources of particulate matter.

The Department approves the requested extension solely for the purposes of constructing the three sugar condition silos (emission points S-13, S-14, and S-15 identified under emissions unit 019) and the powdered sugar/starch bins (emission point S-16 under emission unit 020). This extension does not authorize any other construction activities. The expiration date is hereby extended from **December 31, 2002** to **December 31, 2004**. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

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 (F.S.). 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 (14) 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), F.S., must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code (F.A.C.)

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, F.A.C.

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.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this action will not be effective until further order of the Department.

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

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/18/02 to the person(s) listed:

Mr. William A. Raiola, USSC*
Mr. Peter Briggs, USSC
Mr. Don Griffin, USSC
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD

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.

Victoria Gibson (Clerk) March 18, 2002 (Date)

Memorandum

Florida Department of
Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: March 15, 2002

SUBJECT: United States Sugar Corporation – Clewiston Sugar Mill and Refinery
Extension of Air Construction Permit Expiration Date
Original Project No. 0510003-010-AC
Air Permit No. PSD-FL-272A

Attached for your approval and signature is a permit modification that extends the permit expiration date for the above referenced project. The extension only covers the sugar silos and starch bins, which are small sources of particulate matter.

Day 74 is May 20, 2002. I recommend your approval and signature.

Attachments

CHF/AAL/jfk

U.S. Postal Service
CERTIFIED MAIL RECEIPT
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Postmark Here

Sent To: William A. Raiola
Street, Apt. No.; or PO Box No.: 111 Ponce DeLeon Avenue
City, State, ZIP+4: Clewiston, FL 33440

PS Form 3800, January 2001 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1 Article Addressed to:

Mr. William A. Raiola
Vice President
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* | B. Date of Delivery

C. Signature
X Andrea Soles ☐ Agent ☐ Addressee

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

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

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

2 7001 0320 0001 3692 9199

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-00-M-0952

UNITED STATES POSTAL SERVICE

First-Class Mail
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USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

BUREAU OF AIR REGULATION

RECEIVED

MAR 22 2002

01

Golder Associates Inc.

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

Golder Associates

November 17, 2000

RECEIVED 0037629

NOV 21 2000

BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention: Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
DRAFT PERMIT NO. 0510003-010-AC; PSD-FL-272A

Dear Mr. Koerner:

United States Sugar Corporation (U.S. Sugar) received the draft permit for the above referenced project from the Florida Department of Environmental Protection. The draft permit has been reviewed, and several comments and concerns have been identified. The comments are addressed below, in the same order as they appear in the draft permit.

Cover Letter
Mr. Brinson has retired from U. S. Sugar. Mr. William A. Raiola, Vice President, is now the authorized representative for the Clewiston mill.

Placard Page
Mr. William A. Raiola, Vice President, is now the authorized representative for the Clewiston mill.

Page 5 of 25
3. Footnote "b" of table: insert the word "(net)" after 1160 Btu in order to clarify that this is the net Btu difference between the steam enthalpy and the feedwater enthalpy.

Page 6 of 25
6. In the second sentence, revise "...from the dedicated storage tank" to "...from a dedicated storage tank", since a tank different than the tank currently used could be utilized in the future.

8. c. The emissions unit description on page 5 of 25 states that a nominal 250 to 500 gallons per minute of water is supplied to the spray nozzles. However, 8.c. states that the water flow rate to the scrubber nozzles shall be maintained above 375 gallons per minute. Based on historic particulate matter (PM) compliance test data for Boiler No. 4, compliance has been demonstrated at scrubber water flow rates of less than 375 gpm. For example, the December 1996 compliance test was conducted with an average scrubber water flow rate of

245 gpm. It is therefore requested that this condition be revised to state that the scrubber water flow rate be maintained at a minimum of 90% of the water flow at which the scrubber was operated during the latest compliance test that demonstrated compliance with the PM emission limit (as a 3-hour block average).

Page 8 of 25

15. It is noted that consent order 00-0908-26-AP dated August 1, 2000, requires U. S. Sugar to perform twelve (12) 1-hour VOC runs on Boiler No. 4, to be conducted with the CO compliance testing to be performed during the 2000-2001 sugar processing season. Based on the VOC testing, the permittee may apply for a revised VOC limit, and the Department must establish a new VOC limit, based upon this testing, which can be achieved through application of good combustion practices.

Page 9 of 25

17. Note that the initial performance tests required for Boiler No. 4 under permit no. 0510003-009-AC; PSD-FL-272) have been completed. This included compliance testing for CO, NO_x, PM/PM_{10}, SO_2, VOC, sulfuric acid mist, visible emissions and a boiler thermal efficiency test. The summary pages from the compliance tests are attached. The test results demonstrated compliance for all pollutants, except for VOC. As described above, VOC is being addressed through a consent order. As a result, and based on our recent conversation, no further testing should be required for sulfuric acid mist emissions.

18. The initial SO_2 tests demonstrated emissions less than 0.03 lb/MMBtu, and a boiler thermal efficiency of greater than 50%. Therefore, no annual testing for these parameters are required (see attached stack test results).

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4. In order to clarify that no additional record keeping is required by this permit, it is requested to reword the first sentence as "The maximum capacities for each boiler are stated below. For Boiler Nos. 1, 2 and 3, the capacities are for informational purposes only". Also, in order to be consistent with condition 10 of this subsection, it is requested that the steam capacities be based upon 3-hour averages. It is not expected that the boilers will be operated at steam rates above the stated 1-hour capacities. However, future permits (i.e., Title V) may require recordkeeping on an hourly basis because of the 1-hour capacities, which would be very burdensome. All air quality modeling analysis were based on 3-hour or longer averaging times, except for the pollutant CO. For CO, the very conservative modeling analysis showed that the maximum 1-hour CO impact would not be approached. Therefore, there is little potential for exceeding the 1-hour CO standard based on specifying 3-hour steam capacities.

4.d. It is requested that the limitations for Boiler No. 4 be deleted, as they are repetitious of other conditions in this permit for Boiler No. 4, and therefore are unnecessary.

4.e. It is requested that the limitations for Boiler No. 7 be deleted, as they are repetitious of conditions in other permits for Boiler No. 7, and therefore are unnecessary here.

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5.b. It is requested that wording be added to this condition to allow fuel oil with sulfur content of greater than 1.6%, if SO_2 testing when burning fuel oil demonstrates equivalent SO_2 emissions (due to removal of SO_2 in the boiler/scrubber system when burning fuel oil). Prior to any such testing, a test plan would be submitted to the Department presenting the fuel oil burning conditions for the boiler, scrubber parameters to be measured, etc.

5.c. It is requested that the limitations for Boiler No. 4 be deleted, as they are repetitious of other conditions in this permit for Boiler No. 4, and therefore are unnecessary.

5.d. It is requested that the limitations for Boiler No. 7 be deleted, as they are repetitious of conditions in other permits for Boiler No. 7, and therefore are unnecessary here.

Page 14 of 25

7.b(1). Please delete this condition. It is unnecessary and unwarranted. The reason for the extensive air modeling analysis conducted by U.S. Sugar, as well as raising the stacks and agreeing to burn lower sulfur fuel oil during the off-season, was to obtain operating flexibility. These efforts were very costly to U. S. Sugar. In addition, the Boiler No. 4 PSD permit specifically allows up to 8,760 hr/yr operation. This condition negates these efforts. The Department and the EPA required U.S. Sugar to model a number of operational scenarios. This included Boiler No. 7 shutdown and only Boiler Nos. 1, 2 and 3 operating during the off-season. Boiler Nos. 1, 2 and 3 had to be treated as totally increment consuming during the off-season. U. S. Sugar should have the flexibility to operate any of the five boilers throughout the year to meet steam demands as well as maintenance schedules.

In the first sentence after condition 7.b(4), add additional language to cover instrument downtime due to breakdown, malfunction, repair and calibration.

10.a. The requirement to calculate and record the 24-hour average steam production rate based on the actual operating hours during the 24-hour period could result in erroneous actual steam rates. For example, under this condition, if a boiler only operated 6 hours during a day, the average 6-hour steam production during this period would also be recorded as the average 24-hour steam rate. However, the actual 6-hour average steam production can be above the permitted 24-hour steam rate, since the 3-hour limitation is higher than the 24-hour limitation. Therefore, the 24-hour average steam rate should be based on 24-hours no matter the actual hours the boiler operated.

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11. Reword the second sentence as: "From this data, the permittee shall calculate and record the **combined** oil firing rates (gallons) for each 3-hour and each 24-hour block of operation for Boiler Nos. 1 – 4."

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1,2. These conditions should specifically state that Subpart Kb applies to EU 024 and 026.

5. Replace the word "facility" with the word "tank" at the end of this condition.

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9. Note that the initial performance tests required for the GCRF under permit no. 0510003-009-AC; PSD-FL-272) have been completed. This included compliance testing for PM, VOC and visible emissions. The summary pages from the compliance tests are attached. The test results demonstrated compliance for all pollutants. As a result, and based upon our recent conversation, no further testing should be required except for the operating permit renewal testing.

11. Reword according to the rule language, which describe production rates during compliance testing and provisions if testing is not performed within 90% of maximum.

Page 21 of 25

3. Note that since some of these sources have not yet been constructed, it is requested that the construction expiration date be no sooner than November 1, 2002. U. S. Sugar does not have a definitive schedule for construction of these sources at this time. The following sources have not yet been constructed:

S-13, S-14 and S-15: three (3) sugar silos
S-16: powdered sugar/starch bins

Page 22 of 25

6. Note that the initial performance tests required for the already constructed sources under permit no. 0510003-009-AC; PSD-FL-272) have been completed. This included compliance testing for visible emissions. The summary pages from the compliance tests are attached. The test results demonstrated compliance for all pollutants.

Thank you for consideration of these comments in issuing the final permit. Please call or e-mail me if you have any additional questions concerning this information.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P.E. #19011

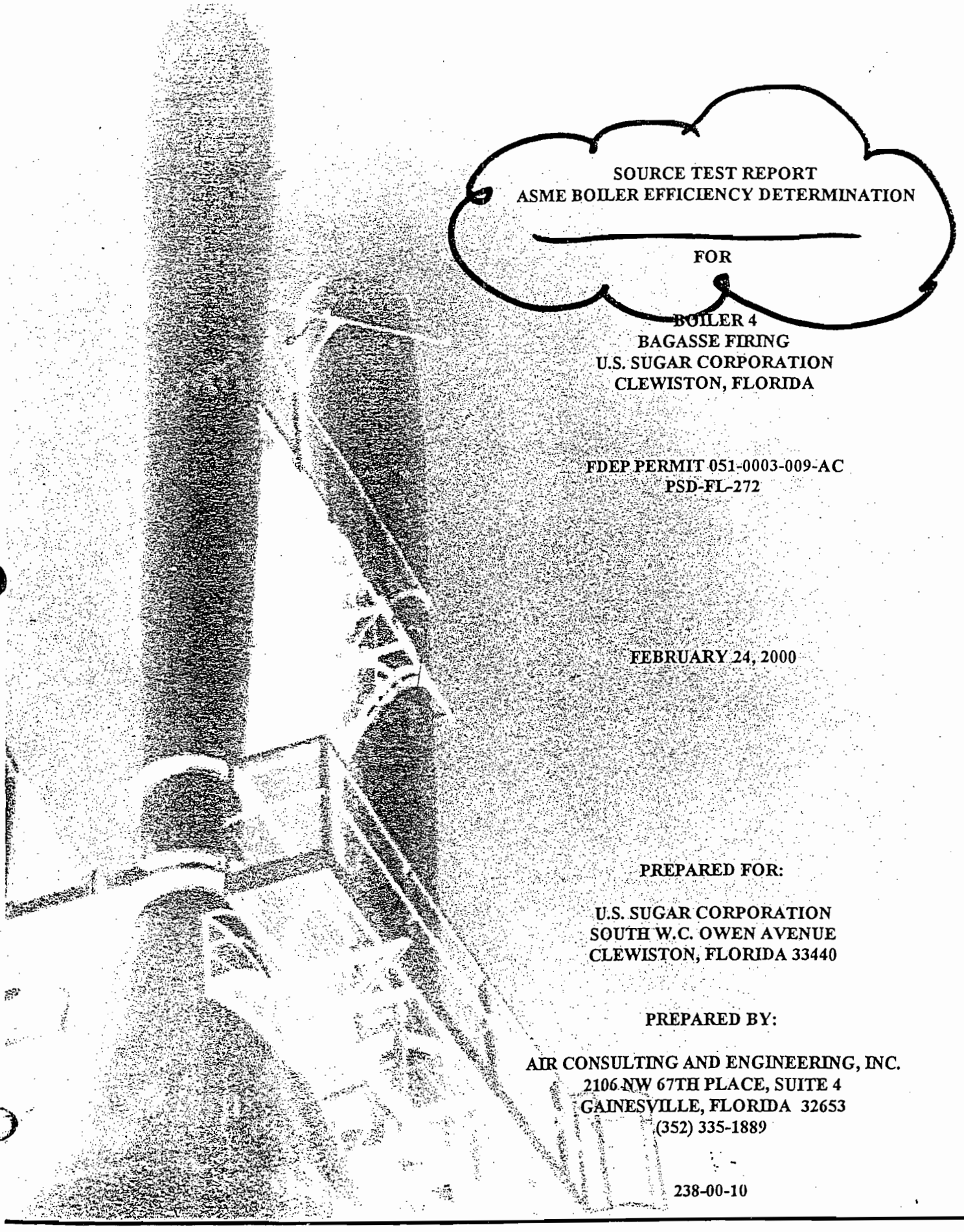
DB/jkw

Attachments

cc: Don Griffin
Bill Wehrum
Lisa Gefen

P:\Projects\2000\0037\0037629a Clewiston Mill\01\#011tr.doc

C. Holladay
R. Blackburn, SD
EPA
NPS



SOURCE TEST REPORT
ASME BOILER EFFICIENCY DETERMINATION

FOR

BOILER 4
BAGASSE FIRING
U.S. SUGAR CORPORATION
CLEWISTON, FLORIDA

FDEP PERMIT 051-0003-009-AC
PSD-FL-272

FEBRUARY 24, 2000

PREPARED FOR:

U.S. SUGAR CORPORATION
SOUTH W.C. OWEN AVENUE
CLEWISTON, FLORIDA 33440

PREPARED BY:

AIR CONSULTING AND ENGINEERING, INC.
2106 NW 67TH PLACE, SUITE 4
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(352) 335-1889

238-00-10

1.0 INTRODUCTION

On February 24, 2000 Air Consulting and Engineering, Inc. (ACE) performed a boiler efficiency test on the Number 4 Boiler at U.S. Sugar Corporation's (USSC) facility in Clewiston, Florida.

Testing was conducted according to the specifications of the American Society of Mechanical Engineer's (ASME) Power Test Code 4.1 (PTC 4.1).

The Boiler Efficiency was determined by the Heat Loss Method (Section 5 of PTC 4.1). This method requires the determination of heat losses and heat credits using results of the proximate and ultimate analysis of a fuel sample, high heat value of the fuel, and fly ash results. Steam output was measured to establish the capacity at which the losses occur.

Testing was conducted using 100% Bagasse Fuel firing at an average steam rate of 195,750 pounds of steam per hour.

Mr. Brett Nesbitt of USSC Clewiston coordinated the test.

2.0 SUMMARY AND DISCUSSION OF RESULTS

The Heat Loss Method was used for calculating boiler efficiency, which resulted in a value of 59.0%.

The following inputs were required for this calculation:

1. Fuel Analysis (Ultimate and Proximate)
2. Flue gas composition
3. Flue gas temperature
4. Temperature of combustion air
5. Combustible content and quantity of dust in exit gases
6. Combustible content and quantity of dust collector hoppers
7. Combustible content and quantity of ash pit refuse
8. Entering fuel temperature
9. Other energy inputs
10. Humidity of combustion air
11. Radiation losses
12. Sensible heat in flue dust
13. Other losses

2.1 Fuel Analysis

Six individual bagasse feed fuel samples were collected over the 1.5-hour duration of the efficiency test. The fuel analysis, ultimate and proximate analysis, was performed by Hazen Research, Inc. (Appendix B) using a composite of these six bagasse samples.

2.2 Flue Gas Composition

United States Environmental Protection Agency's (EPA) Methods 3A, and 10 were conducted by traversing the exhaust stack at a point prior to the primary dust collector, I.D. Fan, and Scrubber (Figure 1). CO concentrations were insignificant and entered as zero values in the PTC 4.1 calculations.

2.3 Flue Gas Temperature

The average flue gas exit temperature was also determined during the traverse conducted in 2.2.

2.4 Combustible Content and Quantity of Flue Gas Dust

EPA Method 5 was used to determine the dust emission rate (see Figure 1 for sampling point location). Of the two stack test ports only one port was utilized to measure O_2, CO_2, PM and CO.

The particulate matter and the fly ash sample collected in the EPA 5 sampling train was analyzed along with a hopper fly ash sample and a grate fly ash sample by Hazen for loss in ignition (% combustible) and % carbon content. These results are also provided in Appendix B. A percentage of the fly ash, hopper and grate ash were added to yield the percent combustible in the refuse sample (Item 22).

2.5 Entering Conditions

The fuel and flue gas temperatures and moisture percentages were measured.

2.6 Radiation and Other Losses

Radiation losses were determined using Figure 8 of PTC 4.1 and were determined to be 0.40 %. "Other Losses" are estimated to be 0.5% of the "as fired" BTU input. This is a typical value.

2.7 SO_2 Reduction Efficiency

SO_2 inlet concentrations were calculated using the sulfur content and the higher heating value from the bagasse analysis. Outlet emissions, measured during the previous compliance test, were 0.00013 lbs/MMBTU. The SO_2 reduction efficiency was 99.92% (see Appendix B for calculations).

3.0 PROCESS DESCRIPTION AND OPERATION

The Number 4 Boiler at USSC's Clewiston facility is a traveling grate stoker design manufactured by Foster Wheeler and capable of producing a maximum of 300,000 lbs/hr of steam at 750 °F and 600 psig. It is primarily used for bagasse fuel firing. Supplemental oil firing was not used during the emission test series. The boiler averaged 195,750 lbs/hr steam production.

Oil meters, steam integrators, and other production monitoring devices were rigorously calibrated prior to the production season.

SUMMARY SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

TEST NO 1 BOILER NO. 4 DATE 2/24/2000

OWNER OF PLANT USSC - Clewiston Mill LOCATION Clewiston, Florida

TEST CONDUCTED BY Air Consulting & Eng., Inc OBJECTIVE OF TEST Boiler thermal eff. DURATION 1.5 HRS

BOILER MAKE & TYPE Foster Wheeler Traveling Grate RATED CAPACITY 300,000 lbs/hr

STOKER TYPE & SIZE Detroit Stoker 633 MMBTU/H 750°F @ 600 psig

PULVERIZER, TYPE & SIZE BURNER, TYPE & SIZE

FUEL USED Bagasse MINE NA COUNTY NA STATE SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	567
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	776
6	STEAM TEMPERATURE AT R H INLET	F	
7	STEAM TEMPERATURE AT R.H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P.P.M.		256
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	80
11	TEMP AIR FOR COMBUSTION (This is Reference Temperature) †	F	80
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	385
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	437

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	1396.7
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	226.7
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	NA
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	NA
20	HEAT ABS LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	1170
21	HEAT ABS. LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	NA
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	0.0354
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	4058.6
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	0.221
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	5.80

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{(\text{Item 28} \times \text{Item 41})}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item 26} \times \text{Item 20}) + (\text{Item 27} \times \text{Item 21}) + \text{Item 30}}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	10
33	O_2	% VOL	8.73
34	CO	% VOL	0
35	N_2 (BY DIFFERENCE)	% VOL	81.27
36	EXCESS AIR	%	66.81

FUEL DATA

	~~Bagasse~~ ~~COAL~~ AS FIRED PROX. ANALYSIS	% wt		OIL			
37	MOISTURE	53.13	51	FLASH POINT F°			
38	VOL MATTER	38.62	52	Sp. Gravity Deg. API°			
39	FIXED CARBON	5.70	53	VISCOSITY AT SSU° BURNER SSF			
40	ASH	2.55	44	TOTAL HYDROGEN % wt			
	TOTAL	100.0	41	Btu per lb			
41	Btu per lb AS FIRED	3636					
42	ASH SDFT TEMP.° ASTM METHOD			GAS	% VOL		
	~~Bagasse~~ ~~COAL OR OIL~~ AS FIRED ULTIMATE ANALYSIS		54	CO			
43	CARBON	23.06	55	CH_4 METHANE			
44	HYDROGEN	2.43	56	C_2H_2 ACETYLENE			
45	OXYGEN	18.62	57	C_2H_4 ETHYLENE			
46	NITROGEN	0.18	58	C_2H_6 ETHANE			
47	SULPHUR	0.03	59	H_2S			
40	ASH	2.55	60	CO_2			
37	MOISTURE	53.13	61	H_2 HYDROGEN			
	TOTAL	100.0		TOTAL			
	COAL PULVERIZATION			TOTAL HYDROGEN % wt			
48	GRINDABILITY INDEX°		62	DENSITY 68 F ATM. PRESS.			
49	FINENESS % THRU 50 M°		63	Btu PER CU FT			
50	FINENESS % THRU 200 M°		41	Btu PER LB			
64	INPUT-OUTPUT EFFICIENCY OF UNIT %			ITEM 31 × 100 / ITEM 29			

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS	424.6	11.68
66	HEAT LOSS DUE TO MOISTURE IN FUEL	630.7	17.35
67	HEAT LOSS DUE TO H_2O FROM COMB OF H_2	259.6	7.14
68	HEAT LOSS DUE TO COMBUST. IN REFUSE	147.7	3.95
69	HEAT LOSS DUE TO RADIATION		0.40
70	UNMEASURED LOSSES		0.50
71	TOTAL		41.02
72	EFFICIENCY = (100 – Item 71)		59.0

° Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

This Test Form (C-36) may be obtained from ASME, 345 E. 47 St., New York, N.Y. 10017

CALCULATION SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

OWNER OF PLANT USSC - Anniston B4 TEST NO. 1 BOILER NO. 4 DATE 2/24/2002

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × [(ITEM 15 − ITEM 17) / 1000] = ... kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL = (% ASH IN AS FIRED COAL) / (100 − % COMB. IN REFUSE SAMPLE)

CARBON BURNED PER LB AS FIRED FUEL = ITEM 43 / 100 − [ITEM 22 × ITEM 23 / 14,500] = 23.06/100 − [0.0354 × 4058.6/14,500] = 0.221

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = [11CO₂ + 8O₂ + 7(N₂ + CO)] / [3(CO₂ + CO)] × (LB CARBON BURNED PER LB AS FIRED FUEL + (3/8) S)

= [11 × ITEM 32 + 8 × ITEM 33 + 7 × (ITEM 35 − ITEM 34)] / [3 × (ITEM 32 + ITEM 34)] × [ITEM 24 + ITEM 47 / 267]

= [11 × 10. + 8 × 8.73 + 7 × (81.37 − 0...)] / [3 × (10.. + 0...)] × [0.221 + 0.03/267] = 5.80

36 EXCESS AIR † = 100 × [O₂ − CO/2] / [.2682N₂ − (O₂ − CO/2)] = 100 × [ITEM 33 − ITEM 34/2] / [.2682 (ITEM 35) − (ITEM 33 − ITEM 34/2)]

= 100 × [8.73 − 0/2] / [.2682 (81.37) − (8.73 − 0/2)] = 66.81

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	LOSS/HHV × 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × (t_{lvg} − t_{air}) = ITEM 25 × 0.24 × (ITEM 13) − (ITEM 11) = 5.80 × 0.24 × (.385 .8.0.. − .4246	424.6	65/41 × 100 =	11.68
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = ITEM 37/100 × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = 630.7	.6307	66/41 × 100 =	17.35
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = 9H_2 × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × ITEM 44/100 × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = .259.6.	259.6	67/41 × 100 =	7.14
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 × ITEM 23 = 0.0354 × 4058.6 = 147.7	147.7	68/41 × 100 =	3.95
69	HEAT LOSS DUE TO RADIATION* = TOTAL BTU RADIATION LOSS PER HR / LB AS FIRED FUEL − ITEM 28	.....	69/41 × 100 =	0.40
70	UNMEASURED LOSSES **	.....	70/41 × 100 =	0.50
71	TOTAL	.....	.....	41.02
	EFFICIENCY = (100 − ITEM 71)	.....	.....	59.0

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

AIR CONSULTING AND ENGINEERING, INC.

ASME BOILER EFFICIENCY TEST

CALCULATION SHEET

COMPANY NAME: United States Sugar Corporation
SOURCE: Boiler 4
LOCATION: Clewiston, Florida

Item 22: Dry Refuse per lb as Fired Fuel

LOI of Fly Ash = 43.17 % used 60% (Appendix B - Laboratory Analysis)
LOI of Hopper Ash = 3.95 % used 30%
LOI of Grate Ash = 5.81 % used 10%

% Combustible in Refuse Sample = 43.17(0.60) + 3.95(0.30) + 5.81(0.10) = 27.99%

$$= \frac{\text{\% Ash in as Fired Bagasse}}{100 - \text{\%Comb.in Refuse Sample}} = \frac{2.55}{100-27.99} = 0.0354 \text{ dry refuse/lb as fired fuel}$$

Item 23: BTU per lb in Refuse

As per PTC 4.1 paragraph 7.3.2.01

= Lab. Determination of % Comb.x 14500 BTU/lb = (27.99/100) 14500 = 4058.6 BTU/lb

Item 66: Heat Loss due to Moisture in Fuel

Enthalpy of Vapor @ 385 F and 1 psia = 1235.1 BTU/lb
Enthalpy of Water @ 80 F amb. Air and 1 psia =48.04 BTU/lb

$$\frac{53.13}{100}(1235.1 - 48.04) = 630.7 \text{ BTU/lb}$$

Item 67: Heat Loss due to H2O from Combustion of H2

Enthalpy of Vapor @ 385 F and 1 psia = 1235.1 BTU/lb
Enthalpy of Water @ 80 F amb. Air and 1 psia =48.04 BTU/lb

$$9\left(\frac{2.43}{100}\right)(1235.1 - 48.04) = 259.6 \text{ BTU/lb}$$

Item 69: Heat Loss due to Radiation

PTC 4.1 Figure 8 at 425 MMBTUH Loss = 0.4 %

Item 70: Unmeasured Losses

Typical Loss = 0.5 %

SOURCE TEST REPORT
FOR
PARTICULATE MATTER, SULFUR DIOXIDE, ACID MIST, CARBON MONOXIDE, OXIDES OF NITROGEN AND NON-METHANE VOLATILE ORGANIC COMPOUNDS EMISSIONS

BOILER 4
IMPINGEMENT WET SCRUBBER OUTLET
TRAVELING GRATE
CLEWISTON, FLORIDA

FDEP PERMIT NUMBER 051-0003-009-AC
PSD-FL-272

JANUARY 5, 2000

PREPARED FOR:

U.S. SUGAR CORPORATION
SOUTH W.C. OWEN AVENUE
CLEWISTON, FLORIDA 33440

PREPARED BY:

AIR CONSULTING AND ENGINEERING, INC.
2106 N.W. 67TH PLACE
GAINESVILLE, FLORIDA 32653
(352) 335-1889

238-00-01

2.0 SUMMARY AND DISCUSSION OF RESULTS

Table 1 is a summary of the emission results and flue gas parameters.

Bagasse and oil were used to fire the boiler.

Particulate emissions averaged 62.19 pounds per hour (lbs/hr) and 0.1223 pounds per million BTU (lbs/MMBTU) of heat input to the boiler. Allowable emissions are 74.40 lbs/hr and 0.146 lbs/MMBTU.

Sulfur Dioxide and acid mist emissions averaged 0.07 lbs/hr and 0.0 lbs/MMBTU, and 0.0 lbs/hr and 0.0 lbs/MMBTU, respectively. Permitted SO_2 emissions are 0.06 lbs/MMBTU.

Oxides of nitrogen emissions averaged 37.57 lbs/hr and 0.074 lbs/MMBTU, which is within the permitted limit of 0.20 lbs/MMBTU.

Carbon monoxide emissions averaged 2934.3 lbs/hr and 5.758 lbs/MMBTU compared to the permitted limit of 6.5 lbs/MMBTU.

Non-methane volatile organic compound emissions averaged 410.54 lbs/hr and 0.805 lbs/MMBTU. The permitted emission standard is 0.5 lbs/MMBTU as propane.

Visible emissions could not be conducted at the time of the compliance test, since the plumes of all boilers merged, making an accurate opacity reading for Boiler 4 impossible.

Complete emission summaries, field data sheets, and laboratory data are presented in Appendices A, B, and C.

Production rate summaries are provided in Appendix E. This data was obtained from control room recordings of steam flow, temperature, and pressure as well as feed water temperature and pressure. Steam integrator readings were recorded at the beginning and at the end of the each particulate run.

Table 1. Particulate and Gaseous Emission Summary
Boiler 4 - Scrubber Outlet
United States Sugar Corporation - Clewiston Mill
Clewiston, Florida
January 5,2000

Run Number	Time	Flow Rate	Particulate Emissions		Allowable Emission		CO Emissions		NOx Emissions		Non-Methane VOC Emissions as Propane	
		dscfm	lbs/MMBTU	lbs/hr	lbs/MMBTU	lbs/hr	lbs/MMBTU	lbs/hr	lbs/MMBTU	lbs/hr	lbs/MMBTU	lbs/hr
1	0950-1059	136759	0.1310	66.45	0.145	73.93	2.76	1404.76	0.089	45.10	0.345	175.54
2	1149-1256	136322	0.1250	64.16	0.146	75.28	7.34	3774.02	0.068	34.83	1.163	598.27
3	1347-1455	135432	0.1110	55.95	0.147	73.99	7.18	3624.11	0.065	32.79	0.907	457.80
Average	---	136171	0.1223	62.19	0.146	74.40	5.758	2934.30	0.074	37.57	0.805	410.54

SO2 Emissions		Acid Mist Emissions	
lbs/MMBTU	lbs/hr	lbs/MMBTU	lbs/hr
0.00E+00	0.00	0.00E+00	0.00
0.00E+00	0.00	0.00E+00	0.00
3.90E-04	0.20	0.00E+00	0.00
1.30E-04	0.07	0.00E+00	0.00

3.0 PROCESS DESCRIPTION AND OPERATIONS

The Number 4 Boiler at USSC's Clewiston plant is a traveling grate stoker design used primarily for bagasse fuel firing. Supplemental oil firing was used during the emission test series. The boiler averaged 238,941 lbs/hr steam production.

Oil meters, steam integrators, and other production monitoring devices were rigorously calibrated prior to the production season.

AIR CONSULTING and ENGINEERING, INC.

COMPLETE EMISSION DATA

UNITED STATES SUGAR CORPORATION
CLEWISTON, FLORIDA
BOILER 4
1/5/2000

RUN NUMBER:		C-1	C-2	C-3	
BEGIN TIME:		9:50 AM	11:49 AM	1:47 PM	
END TIME:		10:59 AM	12:56 PM	2:55 PM	
OXYGEN %:		10.02	9.01	9.25	
VOLUMETRIC FLOW (SCFMD):		136759	136322	135432	
STEAM RATE (LB/HR):		238378	241643.8	236800.0	
NET STEAM (MMBTU/Hr):		509.0	514.5124	504.7973	
OXIDES of NITROGEN (NOx) PPM:		46.03	35.66	33.8	
TOTAL HYDROCARBONS PPM as PROPANE (THC):		204.06	834.04	645.16	
METHANE PPM (CH4):		50	580	455	
CARBON MONOXIDE PPM (CO):		2356.14	6350.25	6138.09	
SULFUR DIOXIDE PPM (SO2):		NA	NA	NA	
NOx:					
	LB/HR:	45.10	34.83	32.79	37.57
	LB/MMBTU	0.089	0.068	0.065	0.07
NON-METHANE VOC as CARBON:					
	LB/HR:	143.65	489.57	374.62	335.95
	LB/MMBTU:	0.282	0.952	0.742	0.66
NON-METHANE VOC as PROPANE:					
	LB/HR:	175.54	598.27	457.80	410.53
	LB/MMBTU:	0.345	1.163	0.907	0.80
CO:					
	LB/HR:	1404.76	3774.02	3624.11	2934.30
	LB/MMBTU:	2.760	7.335	7.179	5.76
SO2:					
	LB/HR:	-0.21	-0.20	0.20	-0.07
	LB/MMBTU:	0.000	0.000	0.000	0.00
PM:					
	LB/HR:	66.45	64.16	55.95	62.19
	LB/MMBTU:	0.131	0.125	0.111	0.122

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

William A. Raiola, Vice President
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Air Permit No. 0510003-010-AC
PSD Permit No. PSD-FL-272A
Boiler No. 4 and Refinery Expansion
Palm Beach County, Florida

Enclosed is Final Permit No. 0510003-010-AC (PSD-FL-272A). This permit authorizes U.S. Sugar Corporation to complete the installation of emissions units associated with refinery operation and finalizes the changes related to the Boiler No. 4 and refinery expansion. As noted in the Final Determination (attached), minor changes to the draft permit were made by the Department, mostly at the request of the applicant. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/8/01 to the person(s) listed:

Mr. William A. Raiola, USSC*
Mr. Dave Buff, Golder Associates
Mr. Phil Barbaccia, South District Office – DEP
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Barbara J. Friday (Clerk) 3/8/01 (Date)

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on October 27, 2000 that modified operation of several Clewiston sugar mill boilers located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on December 27, 2000 and the Department received proof of publication on January 4, 2001. During the 30-day comment period, the Department received comments only from the applicant. The following summarizes the Department's response to each comment and any resulting revision.

APPLICANT'S COMMENTS AND REQUESTS

The Department received written comments from the applicant on November 15, 2000 and January 30, 2001 requesting minor changes. Responses and revisions are summarized below.

Cover Letter and Placard Page

Request: The applicant notes that Mr. Brinson has retired from U. S. Sugar and that Mr. William A. Raiola, Vice President, is now the authorized representative for the Clewiston mill. *Response*: The permit will be revised.

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Request: 3. The applicant requests insertion of the word "net" after 1160 BTU in Footnote "b" of the table to clarify that this is the net BTU difference between the steam enthalpy and the feedwater enthalpy. *Response*: The clarification will be added.

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Request: 6. The applicant requests changing the word "the" to "a" to clarify that a tank different than the tank currently used could be utilized in the future. *Response*: The clarification will be added.

Request: 8. c. The applicant originally requested a lower scrubber flow rate based on previous compliance tests. The January 30th submittal withdrew this request. *Response*: No response required.

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Request: 15. In accordance with a recent Consent Order with the South District Office, the applicant requested a permit revision that required additional VOC testing and perhaps a new VOC limit based on the testing and application of good combustion practices. *Response*: The Consent Order is a stand-alone agreement. The applicant may request revised emissions standards based on additional testing as a permit modification. It would not be sufficient to simply demonstrate that a unit can no longer comply with permitted emissions standards. A test report was received during the processing of this Final Permit indicating that the unit is capable of complying with the current VOC standards. No revision made.

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Request: 17. and 18. The applicant notes that many of the PSD permit conditions have already been met, such as testing. *Response*: The Department notes the comment and is simply providing a full revision so that the PSD permit will be up-to-date. It is recognized that many of the requirements may have been completed. For example, no new "initial" tests are required as a result of this action. No revision was necessary.

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Request: 4. The applicant requested additional clarification to avoid burdensome record keeping and the deletion of steam production limits for Boiler Nos. 4 and 7 because they repetitive. *Response*: The Department

added the following statement to clarify, "The steam production chart records are sufficient to demonstrate compliance with these requirements." The limits will be retained because they specify critical parameters for the Air Quality Analysis, which was the basis of this permit modification.

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Request: 5. The applicant requested additional wording that would allow fuel oil with sulfur content of greater than 1.6%, if SO_2 testing when burning fuel oil demonstrates equivalent SO_2 emissions (due to removal of SO_2 in the boiler/scrubber system when burning fuel oil). The applicant also requests deletion of the fuel sulfur limits for Boiler Nos. 4 and 7 because they are repetitious and unnecessary. *Response*: At the appropriate time, the applicant may request changes to specific permit conditions through the modification process. The limits will be retained because they specify critical parameters for the Air Quality Analysis. No revision made.

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Request: 7.b(1). The applicant initially requested deletion of this condition. The January 30th submittal requested the wording be changed to, "Operation of Boiler No. 7 shall be operated to the greatest extent possible during the off-season, taking into account operating efficiency, steam demands, and boiler availability due to maintenance." *Response*: Unlike the existing sugar mill boilers, Boiler No. 7 was originally permitted to provide steam to the new refinery during the off-season. U.S. Sugar performed an Air Quality Analysis to demonstrate that operation of existing mill boilers during the off-season as backup units to Boiler No. 7 would not have any adverse impacts. To satisfy modeling requirements, the applicant requested a lower sulfur limit on fuel oil for the off-season and a cap on steam production rates. For these reasons, Condition 7.b.(1) was included. To satisfy the applicant's concerns (as agreed), the Department will clarify this condition to read, "During the off-season, Boiler No. 7 shall be operated as the primary unit to meet the steam demands of the refinery. As restricted by the conditions of this permit, other mill boilers may serve as backup units when Boiler No. 7 is down for maintenance, repair or during periods of unusually low steam demand."

Request: 10.a. The applicant expressed concern over calculating the "24-hour average" steam production rate based on actual hours rather than 24-hours. *Response*: The intent of this condition is to demonstrate compliance with Condition No. 7 of the same section. To clarify, the condition will be revised to, "For each 24-hour block of operation, the permittee shall record the total steam production rates (pounds, each) for Boiler Nos. 4 and 7 to demonstrate compliance with Condition No. 7 of this section. ~~The permittee shall calculate and record the 24-hour average steam production rate for these units based on the actual operating hours during the 24-hour period.~~"

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Request: 11. The applicant requests that this condition be clarified with the following change, "From this data, the permittee shall calculate and record the **combined** oil firing rates (gallons) for each 3-hour and each 24-hour block of ~~combined~~ operation for Boiler Nos. 1 – 4." *Response*: Clarification will be added.

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Request: 1,2. The applicant requests the condition to specifically identify that Subpart Kb applies only to EUs 024 and 026. *Response*: The Department will include the following sentence, "The following conditions apply to EUs 024 and 026:"

Request: 5. The applicant requests replacement of the word "facility" with the word "tank" at the end of this condition. *Response*: Permit will be revised.

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Request: 5. The applicant requests that the last four sentences of this condition (related to operations outside the specified range) be added to Condition No. 4 for the afterburner temperature of the GCRF. *Response*: The afterburner temperature is a "set" condition for the control equipment. The permit condition addresses short periods of operation below this level. This was not part of the modification under review. No revision made.

Request: 9. The applicant notes that certain conditions for the GCRF (such as testing) have already been met. *Response*: Again, the Department notes the comment and is simply providing a full revision so that the PSD permit will be up-to-date. It is recognized that many of the requirements may have been completed. For example, no new "initial" tests are required as a result of this action. No revision made.

Request: 11. The applicant requests rewording this condition to reflect the actual rule language, which describes production rates during compliance testing and provisions if testing is not performed within 90% of maximum. *Response*: Section III.G. of the permit does include the applicable rule language. The condition is clarifying that testing should be performed within 90% of the production capacity of the GCRF. No revision made.

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Request: The applicant notes that construction has been delayed for the three sugar silos (S-14, S-14, and S-15) and the powdered sugar/starch bins (S-16). All emissions units are small controlled sources of particulate matter totaling 1.33 TPY. A two-year extension is requested. *Response*: The Department specified an expiration date of December 31, 2002 to allow for the delayed construction. The project description was also revised to reflect remaining construction activities.

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Request: 6. The applicant notes that certain conditions for the particulate matter sources (such as testing) have already been met. *Response*: Again, the Department notes the comment and is simply providing a full revision so that the PSD permit will be up-to-date. It is recognized that many of the requirements may have been completed. For example, no new "initial" tests are required as a result of this action. No revision made.

OTHER CHANGES MADE BY THE DEPARTMENT

Page 1 of 25

During the processing of the Final Permit for this project, the applicant noted that vacuum pan No. 7 remained under construction. The original air construction permit issued in 1996 has an expiration date of October 25, 2001. Although vacuum pan No. 7 was purchased and received in 1997, it was not immediately installed due to a change in sugar market conditions. The applicant now intends to install this equipment and requests that this activity be clarified in the permit. Other than small amounts of isopropyl alcohol, no emissions are directly associated with this unit. The Department included installation of vacuum pan No. 7 in the project description on Page 1 with the remaining construction activities.

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During the processing of the Final Permit for this project, the applicant submitted CO and VOC test data, which was required by original Permit No. PSD-FL-272. Based on the test data and the applicant's proposal, the Department is required to reopen the PSD permit and establish process parameters for the flue gas oxygen content and CO concentration. The Department and applicant agreed to include such parameters into this final permit. On page 7, Specific Condition No. 9 was revised to include an alarm set point of 1.5% for the flue gas

oxygen content and 3000 ppm for the flue gas CO concentration, both based on a 1-hour block average. Minor revisions were also made to Appendix GCP (Good Combustion Practices).

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Section III.C., Description for Emissions Unit 025: Based on the latest response by the applicant, the Department corrected the volume of the storage tank serving Boiler Nos. 1-3 from 600,000 gallons to 400,000 gallons.

CONCLUSION

The Department considers the revisions to be minor. The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE

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

Authorized Representative:
William A. Raiola, Vice President

Permit No.	0510003-010-AC
PSD No.	PSD-FL-272A
Project:	Boiler No 4 and Refinery Expansion, Revised
SIC No.	2061, 2062
Expires:	December 31, 2002

PROJECT AND LOCATION

This permit authorizes the United States Sugar Corporation to modify operations at its existing sugar mill and refinery. Specifically, the permit allows increased operation of Boiler No. 4 and the existing refinery operation. The only new construction authorized by this permit the installation of three new sugar conditioning silos (emissions points S-14, S-14, and S-15 of EU 019), the installation of additional powdered sugar/starch silos (emissions point S-16 of EU-020), and the installation of vacuum pan No. 7. The revised permit includes new conditions that reflect the air quality analysis based on the ISC PRIME model.

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	Summary of Previous BACT Determination
Appendix GC	General Permit Conditions
Appendix GCP	Good Combustion Practices Plan

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 3/7/01

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 4 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

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
001	Bagasse Boiler No. 1 with wet scrubber (255,000 pounds of steam per hour)
002	Bagasse Boiler No. 2 with wet scrubber (230,000 pounds of steam per hour)
003	Bagasse Boiler No. 3 with wet scrubber (130,000 pounds of steam per hour)
004	Bagasse Boiler No. 5 (inactive, permanently shut down)
005	Bagasse Boiler No. 6 (inactive, permanently shut down)
009	Bagasse Boiler No. 4 with wet scrubber (300,000 pounds of steam per hour)
014	Bagasse Boiler No. 7 with electrostatic precipitator (385,000 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
025	Common fuel storage tank for Boiler Nos. 1 - 3
026	NSPS fuel storage tank for Boiler No. 7

Project No. 0510003-009-AC (Permit No. PSD-FL-272): For the original project, net emissions increases of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC were significant and the permit established emissions standards for these pollutants based on the Best Available Control Technology. Permit issuance was based on an Air Quality Analysis with ISCST3 modeling, increased stack heights for Boiler Nos. 1 – 3, and lower sulfur contents for Boiler Nos. 1 – 3. However, the permit allowed the facility to regain the higher sulfur content oil for use in Boiler Nos. 1 – 3 if a revised Air Quality Analysis demonstrated compliance with the AAQS and PSD increments.

Project No. 0510003-010-AC (Permit No. PSD-FL-272A): The permittee raised the stacks of Boiler Nos. 1-3 to 213 feet. A revised Air Quality Analysis based on the ISC PRIME model resolved potential adverse ambient

impacts and demonstrated compliance with the AAQS and PSD increments. This model was able to evaluate ambient impact contributions resulting from downwash from each stack. EPA Region 4 approved the non-guideline model for use with this project. Although Boiler Nos. 1 - 3 regain the use of fuel oil containing no more than 2.5% sulfur by weight, additional constraints were used in the analysis, which are included as conditions in this permit.

REGULATORY CLASSIFICATION

HAPs: Based on the most recent information for bagasse-fired boilers, this facility is 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.

NSPS Sources: Fuel oil storage tanks (Emissions Unit Nos. 024 and 026) are subject to regulation under the New Source Performance Standards of 40 CFR 60, Subpart Kb.

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.

- EPA Region 4's approval on November 4, 1999 of the ISC Prime model for use with this project.
- Initial permit application received June 25, 1999, associated correspondence to make complete, and final permit issued on November 22, 1999.
- Permit application for revision received January 6, 2000 and associated correspondence to make complete.

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

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

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-210, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.). The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. Operation Permit Required: This permit authorizes modification of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. In accordance with Chapter 62-213, F.A.C, the permittee shall apply for a Title V operation permit on the appropriate application form with 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 No.	Emissions Unit Description
009	Boiler No. 4: 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.) 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 psig. The differential pressure drop across the wet scrubber is maintained between 8 and 11 inches of water column. Exhaust gases exit the wet scrubber at an average flow rate of 281,000 ACFM at 160° F. The stack is 150 feet high (GEP stack height is 225 feet high).

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

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Pursuant to Rule 62-212.400, F.A.C., this emissions unit is subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), 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 (net) 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: Any 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 from a dedicated storage tank. 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. Boiler No. 4 shall fire no more than 1500 gallons in any hour and no more than 500,000 gallons in any consecutive 12-month period. The permittee shall install, calibrate, operate, and maintain an individual fuel oil flow meter with integrator. Compliance with these limits shall be determined by the monitoring and record keeping requirements of this permit. [Applicant Request, Rule 62-210.200 (Definitions - PTE) and Rule 62-212.400 (BACT), F.A.C.]

7. Common Conditions: See Section III.B., "Common Conditions for Boiler Nos. 1 - 7" for other performance restrictions.

CONTROL EQUIPMENT AND TECHNIQUES

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

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

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

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

   The monitoring equipment shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations. The permittee shall read and record each scrubber parameter once

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

9. Good Combustion Practices: The boiler operator shall use the Good Combustion Practices (GCPs) defined in *Appendix GCP* to minimize emissions of CO, NOx, PM/PM10 and VOC from this boiler. As a critical part of the GCPs, the permittee shall install, calibrate, operate, and maintain process monitors to indicate the oxygen and carbon monoxide content of the exhaust flue gas in the boiler furnace. The oxygen process monitor shall include an alarm with a set point at 1.5% (minimum) flue gas oxygen content based on a 1-hour block average. It shall display both the instantaneous and the 1-hour block average of the flue gas oxygen content (in percent oxygen). The CO process monitor shall include an alarm with a set point at 3000 ppm (maximum) flue gas CO concentration based on a 1-hour block average. It shall display both the instantaneous and the 1-hour block average of the flue gas CO concentration (in ppm). Readouts of these process monitors shall be provided in the boiler control room. If the alarm is tripped for either process monitor (low oxygen content or high CO concentration), the boiler operator shall take corrective actions consistent with good combustion practices. Corrective actions include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, firing some fuel oil in place of bagasse. For each such incident, the operator shall summarize the corrective actions taken and the approximate time when operation within the target parameter(s) was regained. 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. Operation outside of the specified operating range for either monitored parameter is not a violation of this permit, in and of itself. However, continued or frequent operation outside of the specified operating range for either monitored parameter without corrective action may be considered circumvention of "good combustion practices". [Rules 62-4.070(3) and 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/PM10: Particulate matter emissions shall not exceed 0.15 pounds per mmBTU of heat input from bagasse firing nor 0.10 pounds per mmBTU of heat input from oil firing based on a 3-run test average as

determined by EPA Method 5. Compliance when firing both fuels shall be determined by prorating the emissions standards based on the heat input from each fuel. [Applicant Request; Rules 62-296.410(2)(b)2. and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

21. Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the scrubber pressure drop, the scrubber water supply line pressure, the scrubber water flow rate, the flue gas oxygen content, and the flue gas carbon monoxide content at 15 minute intervals. The permittee shall monitor and record the steam production rate, steam temperature, steam pressure, feed water flow rate, feed water temperature, feed water pressure, and oil flow rate and calculate and record the bagasse consumption rate and the heat input for each run. [Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

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

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

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

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

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

e. **Oil Firing**: The permittee shall record the oil-firing rate (gallons) for each 3-hour block of operation. In addition, the permittee shall calculate and record the oil-firing rate (gallons) for each 24-hour block of operation. Oil firing rates may be observed and recorded by hand or automated monitoring equipment.

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

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

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

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

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

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

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

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

B. EU 001, 002, 003, 004, 005, 009, and 014 - Common Conditions for Boiler Nos. 1 - 7

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

EU No.	Emissions Unit Description
001	Bagasse Boiler No. 1 with wet scrubber (255,000 pounds of steam per hour)
002	Bagasse Boiler No. 2 with wet scrubber (230,000 pounds of steam per hour)
003	Bagasse Boiler No. 3 with wet scrubber (130,000 pounds of steam per hour)
004	Bagasse Boiler No. 5 (inactive, permanently shut down)
005	Bagasse Boiler No. 6 (inactive, permanently shut down)
009	Bagasse Boiler No. 4 with wet scrubber (300,000 pounds of steam per hour)
014	Bagasse Boiler No. 7 with electrostatic precipitator (385,000 pounds of steam per hour)

The PSD permit for Boiler No. 4 (PSD-FL-272A) was issued based on an Air Quality Analysis using the ISC PRIME model that contained several operational constraints on existing emissions units. These constraints are now enforceable conditions of the permit and are in addition to any limits imposed by other valid permits. Modification of these constraints would require modification of the PSD permit and a new Air Quality Analysis.

PERFORMANCE RESTRICTIONS

1. Permanent Shutdown: Boiler Nos. 5 and 6 shall remain permanently shut down and rendered incapable of operation. These units are no longer available as "standby" units. Any proposed future operation of either boiler would require a preconstruction review permit as a "new" unit. [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

2. Modified Stack Heights: The stacks for Boiler Nos. 1, 2, and 3 shall be maintained at a minimum of 213 feet in height. [Design, Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

3. Crop Season: For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

4. Capacities: For each boiler, the maximum 1-hour operating capacities shall not exceed:

   a. **Boiler No. 1**: 255,000 pounds of steam per hour, 495 mmBTU per hour of total heat input, and 1500 gallons of oil per hour

   b. **Boiler No. 2**: 230,000 pounds of steam per hour, 447 mmBTU per hour of total heat input, and 1500 gallons of oil per hour

   c. **Boiler No. 3**: 130,000 pounds of steam per hour, 265 mmBTU per hour of total heat input, and 900 gallons of oil per hour

   d. **Boiler No. 4**: 300,000 pounds of steam per hour, 633 mmBTU per hour of total heat input, and 1500 gallons of oil per hour

   e. **Boiler No. 7**: 385,000 pounds of steam per hour, 812 mmBTU per hour of total heat input, and 1839 gallons of oil per hour

   {Permitting Note: No additional record keeping requirements are imposed by these conditions. The steam production chart records are sufficient to demonstrate compliance with these requirements.}

   [Design, Supporting Air Quality Analysis for PSD-FL-272A]

5. Fuel Oil Sulfur Contents

   a. **Boiler Nos. 1 - 3, Crop Season**: From October through April of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 2.50% sulfur by weight.

   b. **Boiler Nos. 1 - 3, Off-Season**: From May through September of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 1.60% sulfur by weight. In April of each year, a composite sample from the common tank shall be taken and analyzed for the sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. If the sulfur content is higher than 1.60% sulfur by weight, the permittee shall purchase additional oil to blend down to the permit limit before any fuel from the common tank is authorized for firing during the off-season. An additional composite sample shall be taken from the common tank after blending and analyzed for the fuel sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. It is a violation of this permit to fire fuel from the common tank without filing a report with the Compliance Authority that demonstrates compliance with the lower fuel sulfur limit. Thereafter, only fuel oil containing no more than 1.60% sulfur by weight shall be purchased and added to the common tank during the off-season. It is the permittee's responsibility to appropriately plan for and stage fuel purchases to comply with this condition.

   c. **Boiler No. 4**: Any fuel oil fired in Boiler No. 4 shall contain no more than 0.70% sulfur by weight.

   d. **Boiler No. 7**: Any distillate oil fired in Boiler No. 7 shall contain no more than 0.05% sulfur by weight.

   The permittee shall maintain fuel records that indicate compliance with the above conditions for each fuel oil purchase at each tank. The sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. For each shipment, a certified analysis supplied by the fuel oil vendor is sufficient to demonstrate compliance.

   [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

6. Fuel Oil Consumption

   a. **Boiler Nos. 1 - 4, Crop Season**: From October through April of each year, the total fuel oil consumption for Boiler Nos. 1 - 4 shall not exceed 16,200 gallons during any 3-hour period and 88,800 gallons during any 24-hour period.

   b. **Boiler Nos. 1 - 4, Off-Season**: From May through September of each year, the total fuel oil consumption for Boiler Nos. 1 - 4 shall not exceed 11,700 gallons during any 3-hour period and 54,000 gallons during any 24-hour period.

   The permittee shall install, calibrate, operate, and maintain individual fuel oil flow meters with integrators.

   [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

7. Steam Production

   a. **Crop Season and Off-Season**

      (1) Boiler No. 4 shall not produce more than 6,840,000 pounds of steam during any 24-hour period.

      (2) Boiler No. 7 shall not produce more than 8,400,000 pounds of steam during any 24-hour period.

b. **Off-Season (May through September)**

(1) During the off-season, Boiler No. 7 shall be operated as the primary unit to meet the steam demands of the refinery. As restricted by the conditions of this permit, other mill boilers may serve as backup units when Boiler No. 7 is down for maintenance, repair or during periods of unusually low steam demand.

(2) For Boiler Nos. 1 - 4, no more than three of these boilers shall operate simultaneously.

(3) For Boiler Nos. 1 - 4, the total steam production shall not exceed 1,845,000 pounds of steam during any 3-hour period.

(4) For Boiler Nos. 1 - 4, the total steam production shall not exceed 10,800,000 pounds of steam during any 24-hour period.

The permittee shall install, calibrate, operate, and maintain equipment to continuously record the steam production rates. The permittee shall also install, calibrate, operate, and maintain a steam flow integrator to record the accumulated steam flow rate.

[Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

8. Modifications: A request to modify any of these conditions shall be accompanied by a revised Air Quality Analysis that demonstrates compliance with the Ambient Air Quality Standards and PSD increments for the revised conditions.

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

PERFORMANCE TESTING

9. SO_2 Tests: To validate the SO_2 emission factor for Boiler Nos. 1 - 3, the permittee shall conduct emissions performance tests in accordance with EPA Method 6 or 6C for at least one of these boilers when firing only bagasse. The initial test shall be conducted between October 1, 2000 and February 1, 2001. Thereafter, at least one of these boilers shall be tested within the 12-month period prior to renewal of the air operation permit. Tests need not be conducted on the same boiler. Based on the results of the performance tests, the Compliance Authority may require additional testing or an additional Air Quality Analysis.

{Permitting Note: The expected emission factor is 0.06 pounds of SO_2 per mmBTU when firing only bagasse. This is not a permit limit for Boiler Nos. 1 - 3. Performance tests, notifications, reports, etc., are subject to the requirements listed in Section III.G. of this permit.}

[Supporting Air Quality Analysis for PSD-FL-272A]

REPORTING AND RECORD KEEPING REQUIREMENTS

10. Steam Production

a. **Crop Season and Off-Season**: For each 24-hour block of operation, the permittee shall record the total steam production rates (pounds, each) for Boiler Nos. 4 and 7 to demonstrate compliance with Condition No. 7 of this section.

b. **Off-Season**

(1) From May through September, the permittee shall record the individual and total steam production rates (pounds) for Boiler Nos. 1 - 4 for each 3-hour block when three of the boilers are in operation.

(2) From May through September, the permittee shall record the individual and total steam production rates (pounds) for Boiler Nos. 1 - 4 for each 24-hour block of operation.

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

11. Fuel Oil Consumption: For Boiler Nos. 1 - 4, the permittee shall record the oil-firing rates (gallons) for each 3-hour block of operation. From this data, the permittee shall calculate and record the combined oil firing rates (gallons) for each 3-hour and each 24-hour block of operation for Boiler Nos. 1 - 4.

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

12. Fuel Sulfur Content: For each fuel oil delivery, the permittee shall record and retain the following: the date, identification of the tank, the gallons of fuel delivered, the fuel oil analysis including the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable. This condition applies to each tank supplying fuel to any boiler.

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

ORIGINAL

Golder Associates Inc.

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

December 16, 1999

9937606

U.S. Sugar Corporation

111 Ponce de Leon Avenue
Clewiston, FL 33440

Attention: Mr. Don Griffin

RE: U.S. SUGAR CORPORATION CLEWISTON SUGAR REFINERY
1999 USEPA METHOD 9 VISIBLE EMISSION TEST RESULTS

Dear Mr. Griffin:

On December 9, 1999, Golder Associates Inc. performed visible emissions (VE) testing on the baghouse exhausts controlling the following sources: 1) Screening & Distribution Vacuum System; 2) 100 lb. Bagging Vacuum System; 3) 5 lb. Bagging Vacuum System; 4) Packaging Dust Collector; 5) Screening and Distribution #1; 6) Conditioning Silo's 2,4, and 6; 7) White Sugar Dryer; and 8) VHP Sugar Dryer. According to the results from these observations, the USSC Clewiston Sugar Refinery meets the conditions outlined by the Air Construction Permit # 0510003-001-AC and is therefore in compliance.

The visible emission tests were observed by Mr. Earl Baker of the Florida Department of Environmental Protection.

Enclosed please find copies of the data sheets and VE certifications for submittal to the regulatory agency. Should you have any questions concerning these tests please feel free to contact me at 352-336-5600.

Sincerely,

GOLDER ASSOCIATES, INC.

Michael J. Arrants
Certified VE Evaluator

David A. Buff

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

Enclosures

USSC99VE

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	Page	of
USSO1	1	1

Continued on VEO Form Number: N/A

Method Used (Circle One): **Method 9** 203A 203B Other: _____

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process	Unit #	Operating Mode
SCREENING & DIST. VACUUM	S-1	MAX CAP
Control Equipment		**Operating Mode**
HOFFMAN BAGHOUSE		NORMAL

Describe Emission Point: ~3" ROUND DUCT PROTRUDING HORIZONTALLY THROUGH WALL WESTERN MOST OF 3

Height of Emission Point		Height of Emission Point Ref. to Observer	
Start ~65'	End ~65'	Start ~40'	End ~60'
Distance to Emission Point		**Direction to Emission Point (Degrees)**	
Start ~215	End ~215	Start 325	End 325°

Vertical Angle to Obs. Pt.		Direction to Obs. Pt. (Degrees)	
Start 16°	End 16°	Start 325	End 325°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

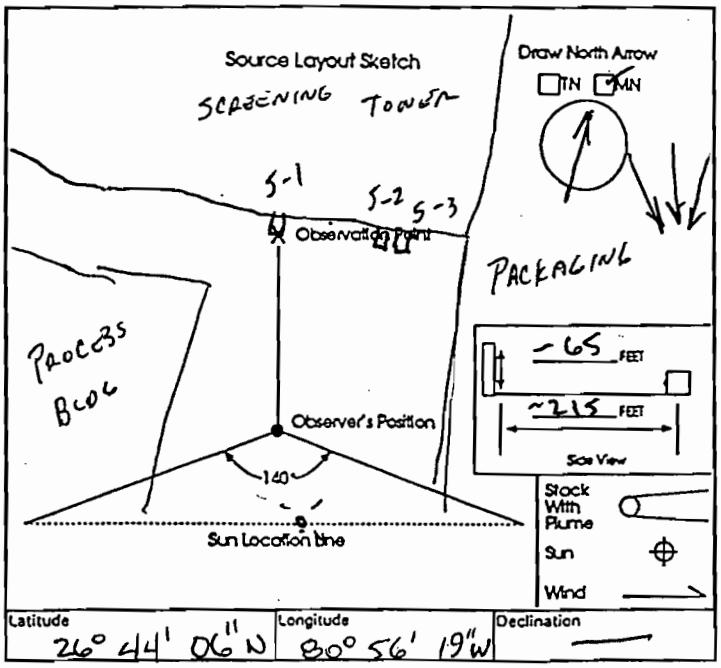
Describe Emissions: Start NONE APPARENT End N/A

Emission Color		Water Droplet Plume	
Start N/A	End N/A	Attached ☐ Detached ☐ None ☑	

Describe Plume Background: Start BLDG FACE End SAME

Background Color		Sky Conditions	
Start GRAY	End GRAY	Start CLEAR	End CLEAR
Wind Speed		**Wind Direction**	
Start 5-10	End 5-10	Start VARIABLE NORTHERLY	End SAME
Ambient Temp.		**Wet Bulb Temp.**	**RH Percent**
Start 74	End 74	67	69

Source Layout Sketch



Latitude	Longitude	Declination
26° 44' 06" N	80° 56' 19" W	—

Additional Information: 051003-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	0920	0950

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
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26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: _____ Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES Date: 24 AUG 99

FORMS/VEOF (02/18/97)

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number: U S S 0 2 | Page 1 of 1

Continued on VEO Form Number: N/A

Method Used (Circle One): Method 9 | 203A | 203B | Other: _____

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 82

City: CLEWISTON | State: FL | Zip: 33440

Process: 100 lb BAGGING VACCUM SYSTEM | Unit #: S-2 | Operating Mode: MAX CAP

Control Equipment: BAG HOUSE (HOFFMAN) | Operating Mode: NORMAL

Describe Emission Point: ~3" ROUND STACK PROTRUDING HORIZONTAL THROUGH SCREENING TOWER SOUTH WALL

Height of Emission Point: Start ~65' End ~65 | Height of Emission Point Rel. to Observer: Start ~60' End

Distance to Emission Point: Start ~212' End ~212 | Direction to Emission Point (Degrees): Start 327° 30' End 327° 30'

Vertical Angle to Obs. Pt.: Start 16° End 16° | Direction to Obs. Pt. (Degrees): Start 327° 30' End 327° 30'

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

Describe Emissions: Start NONE APPARENT End N/A

Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

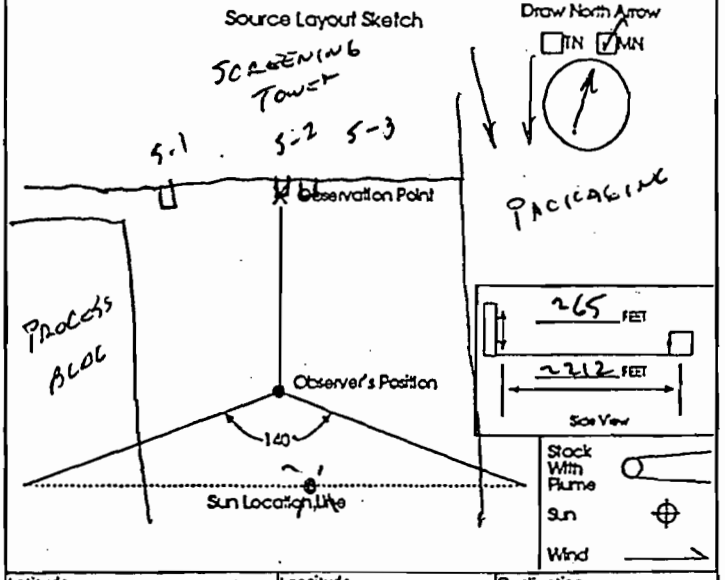
Describe Plume Background: Start BLDG FACE End SAME

Background Color: Start GRAY End GRAY | Sky Conditions: Start CLEAR End CLEAR

Wind Speed: Start 5-10 End 5-10 | Wind Direction: Start VARIABLE NORTHERLY End SAME

Ambient Temp.: Start 74 End 74 | Wet Bulb Temp.: 67 | RH Percent: 69

Source Layout Sketch



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510603-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	0920	0950

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
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9	0	0	0	0
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21	0	0	0	0
22	0	0	0	0
23	0	0	0	0
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25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

FORMS/VEOF (02/18/97)

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Method Used (Circle One): Method 9 | 203A | 203B | Other: _____

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: 5lb BAGGING VACUUM SYSTEM | Unit #: S-7 | Operating Mode: MAX CAP

Control Equipment: HOFFMAN BAG HOUSE | Operating Mode: NORMAL

Describe Emission Point: ~3" STACK PROTRUDING HORIZONTALLY THROUGH SCREENING TOWER WALL, EAST OF 3

Height of Emission Point: Start 65' End 65' | Height of Emission Point Ref. to Observer: Start ~60' End ~60'

Distance to Emission Point: Start ~211' End ~211' | Direction to Emission Point (Degrees): Start 328° End 328°

Vertical Angle to Obs. Pt.: Start 16° End 16° | Direction to Obs. Pt. (Degrees): Start 328° End 329°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End 5'

Describe Emissions: Start NONE APPARENT End N/A

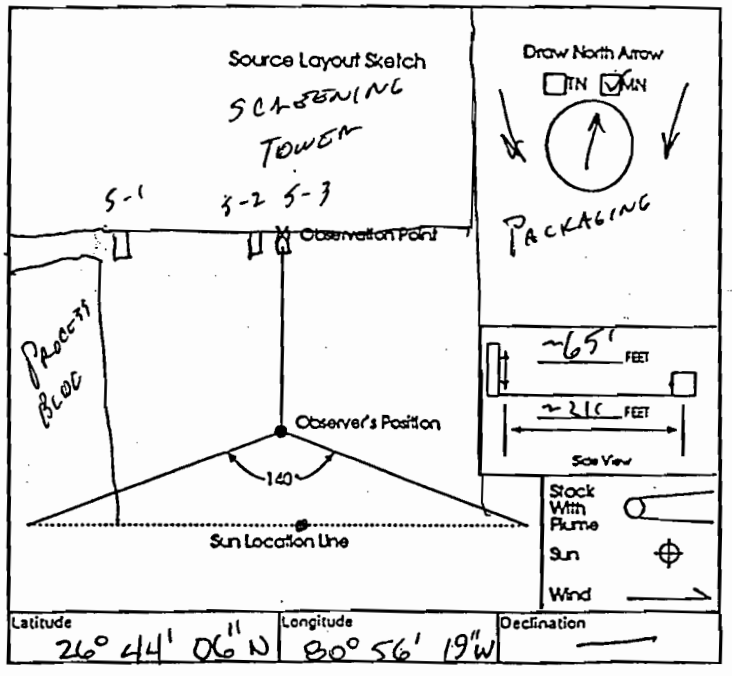
Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

Describe Plume Background: Start BLDG FACE End SAME

Background Color: Start GRAY End GRAY | Sky Conditions: Start CLEAR End CLEAR

Wind Speed: Start 5-10 End 5-10 | Wind Direction: Start VARIABLE NORTHERLY End SAME

Ambient Temp.: Start 74 End 74 | Wet Bulb Temp.: 67 | RH Percent: 69



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510003-001-AC

FORMS/VEOF (02/18/97)

Form Number: U S S 0 3 | Page 1 of 1

Continued on VEO Form Number: N/A

Observation Date: 9 DEC 99 | Time Zone: EAST | Start Time: 0920 | End Time: 0950

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
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9	0	0	0	0
10	0	0	0	0
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21	0	0	0	0
22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	Page	of
USS04	1	1

Continued on VEO Form Number: N/A

Method Used (Circle One): **Method 9** 203A 203B Other:

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: SCREENING & DISTRIBUTION | Unit #: 3-5 | Operating Mode: MAXIMUM

Control Equipment: BAGHOUSE HOSOKAWA | Operating Mode: NORMAL

Describe Emission Point: ~12' x 12" DUCT PROTRUDING HORIZONTALLY THROUGH SCREENING TOWER SOUTH BLDG FACE

Height of Emission Point: Start ~70 End 270 | Height of Emission Point Ref. to Observer: Start ~65 End ~65

Distance to Emission Point: Start ~210 End | Direction to Emission Point (Degrees): Start 332° End 332°

Vertical Angle to Obs. Pt.: Start 18° End | Direction to Obs. Pt. (Degrees): Start 332° End 332°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End N/A

Describe Emissions: Start NONE APPARENT End N/A

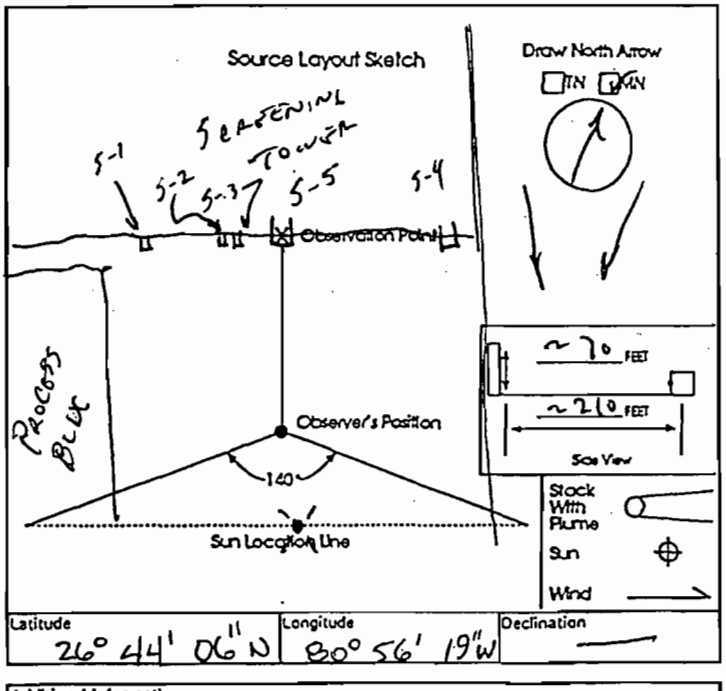
Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

Describe Plume Background: Start BLDG FACE End SAME

Background Color: Start GRAY End GRAY | Sky Conditions: Start CLEAR End CLEAR

Wind Speed: Start 5-15 End 5-15 | Wind Direction: Start NORTHERLY End SAME

Ambient Temp.: Start 74 End 74 | Wet Bulb Temp.: 67 | RH Percent: 69



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510603-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	0955	1025

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
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24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	Page	of
USS-5	1	1

Continued on VEO Form Number: N/A

Method Used (Circle One): Method 9 | 203A | 203B | Other:

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: PACKAGING DUST COLLECTOR | Unit #: 5-4 | Operating Mode: MAX CAP

Control Equipment: DUST COLLECTOR (HOSOKAWA) | Operating Mode: NORMAL

Describe Emission Point: ~12"X18" VENT PROTRUDING HORIZONTAL THROUGH SOUTH WALL OF SCREEN TWR

Height of Emission Point: Start ~63' End ~63' | Height of Emission Point Ref. to Observer: Start ~58' End ~58'

Distance to Emission Point: Start ~210' End ~210' | Direction to Emission Point (Degrees): Start 349° End 349°

Vertical Angle to Obs. Pt.: Start 16° End 16° | Direction to Obs. Pt. (Degrees): Start 349° End 349°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

Describe Emissions: Start NONE APPARENT End N/A

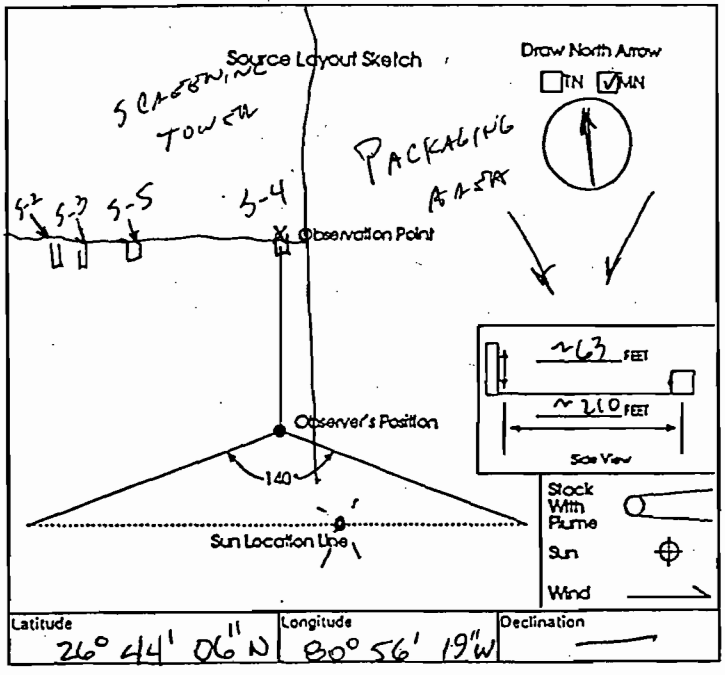
Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

Describe Plume Background: Start BLDG FACE End SAME

Background Color: Start GRAY End GRAY | Sky Conditions: Start CLEAR End CLEAR

Wind Speed: Start 5-15 End 5-15 | Wind Direction: Start NORTHERLY End VARIABLE SAME

Ambient Temp.: Start 74 End 74 | Wet Bulb Temp.: 67 | RH Percent: 69



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination:

Additional Information: 0510603-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	955	1025

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
11	0	0	0	0
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20	0	0	0	0
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25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	Page	of
USSO6	1	1

Continued on VEO Form Number: N/A

Method Used (Circle One): **Method 9** 203A 203B Other: _____

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: CONDITIONING SILO 2 | Unit #: 5-7 | Operating Mode: MAX CAP

Control Equipment: HOSOKAWA BAGHOUSE | Operating Mode: NORMAL

Describe Emission Point: "6X12" RECTANGULAR DUCT PROTRUDING THROUGH SOUTH WALL OF CONVEYOR

	Start	End
Height of Emission Point	~110'	~110'
Height of Emission Point Ref. to Observer	+105'	+105
Distance to Emission Point	~40'	~40'
Direction to Emission Point (Degrees)	325	325
Vertical Angle to Obs. Pt.	68°	69°
Direction to Obs. Pt. (Degrees)	325	325

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

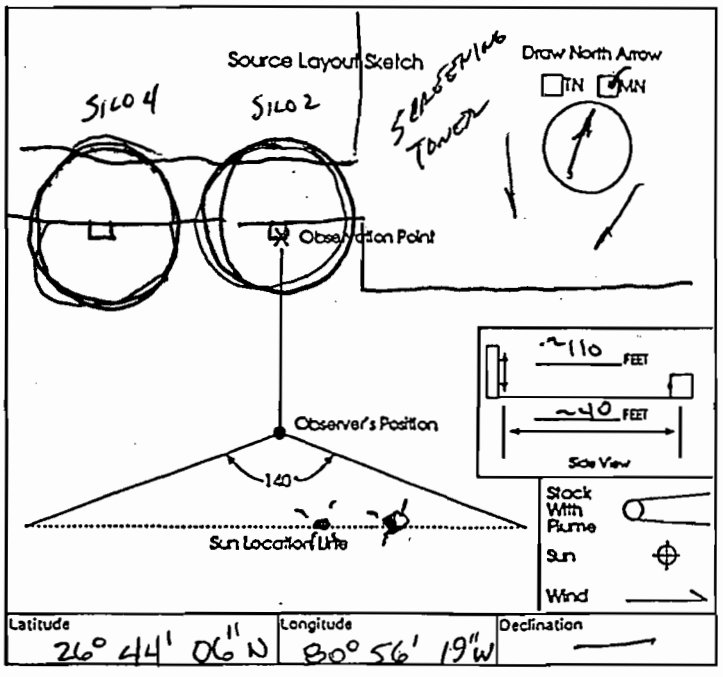
Describe Emissions: Start NONE APPARENT End N/A

Emission Color: Start N/A End N/A

Water Droplet Plume: Attached ☐ Detached ☐ None ☑

Describe Plume Background: Start SKY End SKY

	Start	End
Background Color	BLUE	BLUE
Sky Conditions	CLEAR	CLEAR
Wind Speed	5-15	5-15
Wind Direction	NORTHEAST	SAME
Ambient Temp.	74°F	74°F
Wet Bulb Temp.	67	
RH Percent	69	



Latitude	Longitude	Declination
26° 44' 06" N	80° 56' 19" W	

Additional Information: 0510603-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	1032	1102

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
11	0	0	0	0
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22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES Date: 24 AUG 99

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Method Used (Circle One): **Method 9** 203A 203B Other: _____

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: CONDITIONING SILO #4 | Unit #: 5-8 | Operating Mode: MAX CAP

Control Equipment: HOSOKAWA BAGHOUSE | Operating Mode: NORMAL

Describe Emission Point: ~6" X ~12" RECT VENT PROTRUDING FROM SOUTH SIDE COVERED CONVEYOR OVER #4

Height of Emission Point: Start ~110' End ~110 | Height of Emission Point Ref. to Observer: Start ~105 End ~105

Distance to Emission Point: Start ~50' End ~50 | Direction to Emission Point (Degrees): Start 306 End 306°

Vertical Angle to Obs. Pt.: Start 61 End | Direction to Obs. Pt. (Degrees): Start 306 End 306°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

Describe Emissions: Start NONE APPARENT End N/A

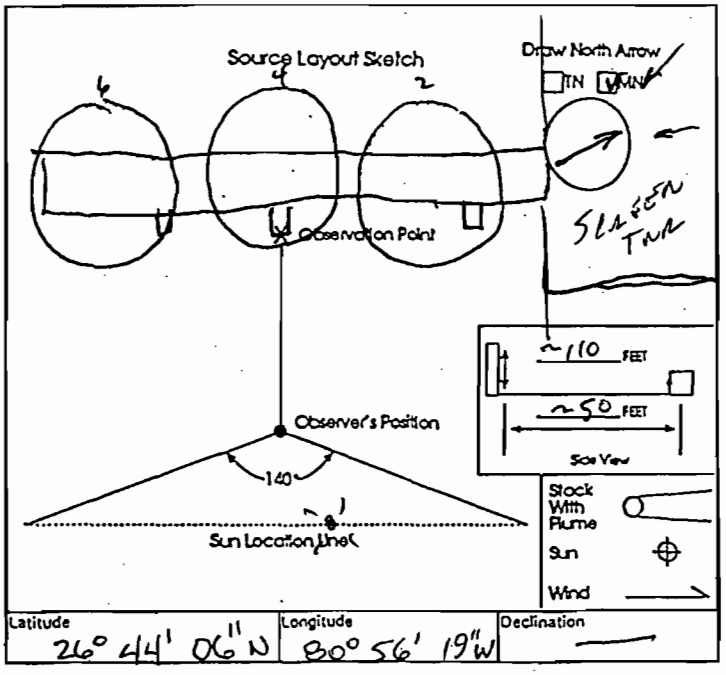
Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

Describe Plume Background: Start SKY End SKY

Background Color: Start BLUE End BLUE | Sky Conditions: Start CLEAR End CLEAR

Wind Speed: Start 5-15 End 5-15 | Wind Direction: Start NORTHERLY End SAME

Ambient Temp.: Start 74 End 74 | Wet Bulb Temp.: 67 | RH Percent: 69



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510603-001-AC

FORMS/VEOF (02/18/97)

Form Number: USS07 | Page 1 of 1

Continued on VEO Form Number: N/A

Observation Date: 9 DEC 99 | Time Zone: EAST | Start Time: 1032 | End Time: 1102

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
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24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: Michael J. Arrants | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	US508	Page 1 of 1
Continued on VEO Form Number	N/A	

Method Used (Circle One): (Method 9) 203A 203B Other: _____

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: CONDITIONING SILO 6 | Unit #: 5-9 | Operating Mode: MAX CAP

Control Equipment: HOSOKAWA BAGHOUSE | Operating Mode: NORMAL

Describe Emission Point: ~6" X 12" RECT. DUCT PROTRUDING HORIZ. THROUGH SOUTH SIDE OF COVERED CONVEYOR

Height of Emission Point: Start ~110' End ~110' | Height of Emission Point Ref. to Observer: Start ~105' End ~105'

Distance to Emission Point: Start ~60' End ~60' | Direction to Emission Point (Degrees): Start 294° End 294°

Vertical Angle to Obs. Pt.: Start 53 End 53° | Direction to Obs. Pt. (Degrees): Start 294° End 294°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End SAME

Describe Emissions: Start NONE APPARENT End N/A

Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

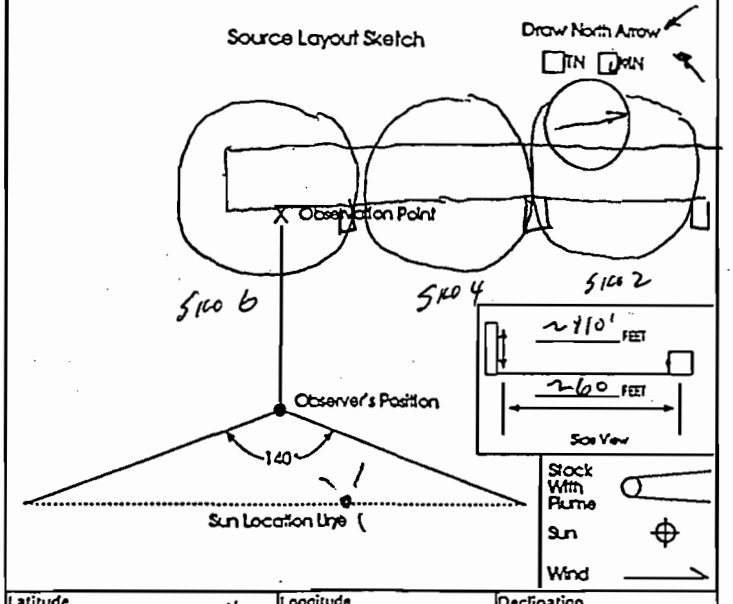
Describe Plume Background: Start SKY End SKY

Background Color: Start BLUE End BLUE | Sky Conditions: Start CLEAR End CLEAR

Wind Speed: Start 5-15 End 5-15 | Wind Direction: Start NORTHERLY VARIABLE End SAME

Ambient Temp: Start 74 End 74 | Wet Bulb Temp. 67 | RH Percent 69

Source Layout Sketch



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510003-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	1032	1102

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
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25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

FORMS/VEOF (02/18/97)

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	Page	of
USS09	1	1

Continued on VEO Form Number: N/A

Method Used (Circle One): Method 9 | 203A | 203B | Other:

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: WHITE SUGAR DRYER | Unit #: 5-10 | Operating Mode: MAX CAP

Control Equipment: BAG HOUSE (BEST ENGINEER.) | Operating Mode: NORMAL

Describe Emission Point: 4X6' VENT AT NORTH EAST CORNER OF PROCESS BLDG.

Height of Emission Point: Start ~80 End ~80 | Height of Emission Point Ref. to Observer: Start ~75' End ~75'

Distance to Emission Point: Start ~170 End ~170 | Direction to Emission Point (Degrees): Start 334° End 334°

Vertical Angle to Obs. Pt.: Start 24° End 24° | Direction to Obs. Pt. (Degrees): Start 334° End 334°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

Describe Emissions: Start PUFFS INTERMITENT End SAME

Emission Color: Start WHITE End WHITE | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

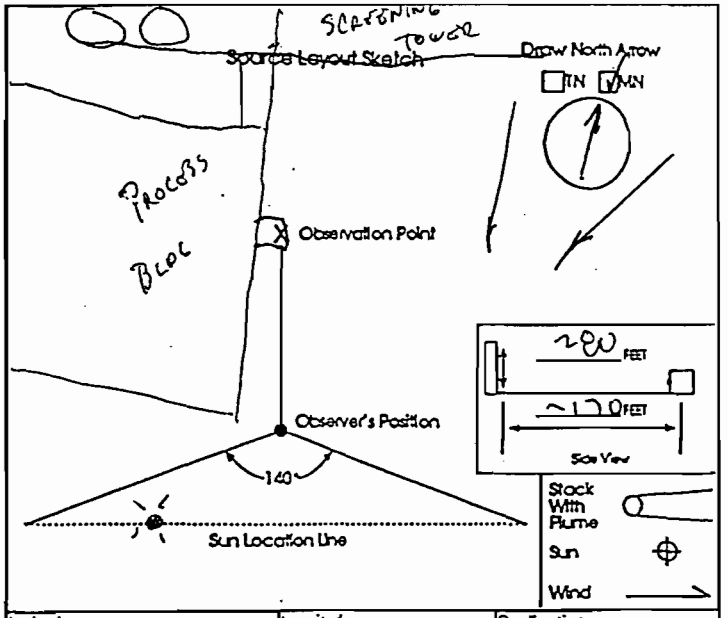
Describe Plume Background: Start BUILDING FACE End SAME

Background Color: Start GRAY End GRAY | Sky Conditions: Start BROKEN End BROKEN

Wind Speed: Start 5-15 End 5-15 | Wind Direction: Start NE-NW End NE-NW (VARIABLE)

Ambient Temp.: Start 78 End 78 | Wet Bulb Temp.: 67 | RH Percent: 56

Source Layout Sketch — Draw North Arrow ☐ TN ☑ MN



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510603-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	1504	1534

Sec / Min	0	15	30	45
1	0	5	0	0
2	0	0	5	0
3	5	5	0	0
4	0	0	0	0
5	5	0	0	5
6	0	5	0	5
7	5	5	0	0
8	5	0	0	0
9	0	0	0	0
10	0	0	5	0
11	0	0	5	5
12	0	5	0	0
13	0	5	0	5
14	0	0	5	0
15	0	0	0	0
16	0	0	5	0
17	0	5	0	0
18	0	5	0	0
19	0	0	0	5
20	0	5	0	0
21	0	0	0	5
22	0	5	0	0
23	0	0	0	0
24	0	0	5	0
25	5	0	0	0
26	0	5	0	0
27	5	0	0	5
28	0	0	0	5
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: 9 DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

FORMS/VEOF (02/18/97)

VISIBLE EMISSION OBSERVATION FORM

Golder Associates

Form Number	Page	of
USS10	1	1

Continued on VEO Form Number: N/A

Method Used (Circle One): Method 9 | 203A | 203B | Other:

Company Name: U.S. SUGAR CORPORATION

Facility Name: CLEWISTON MILL

Street Address: W.C. OWENS AVENUE & SR 832

City: CLEWISTON | State: FL | Zip: 33440

Process: VHP SUGAR DRYER | Unit #: 5-12 | Operating Mode: MAX CAP

Control Equipment: BAGHOUSE (BAST ENG) | Operating Mode: NORMAL

RECTANGULAR INLET 4'X6'

Describe Emission Point: INVOLVED LONE STACK AT SW CORNER OF #3 RAW SUGAR WAREHOUSE

Height of Emission Point: Start ~40' End 40 | Height of Emission Point Rel. to Observer: Start 235 End 235'

Distance to Emission Point: Start ~200' End ~200' | Direction to Emission Point (Degrees): Start 98° End 98°

Vertical Angle to Obs. Pt.: Start 9° End | Direction to Obs. Pt. (Degrees): Start 98° End 98°

Distance and Direction to Observation Point from Emission Point: Start SAME POINT End S/P

Describe Emissions: Start NONE APPARENT End N/A

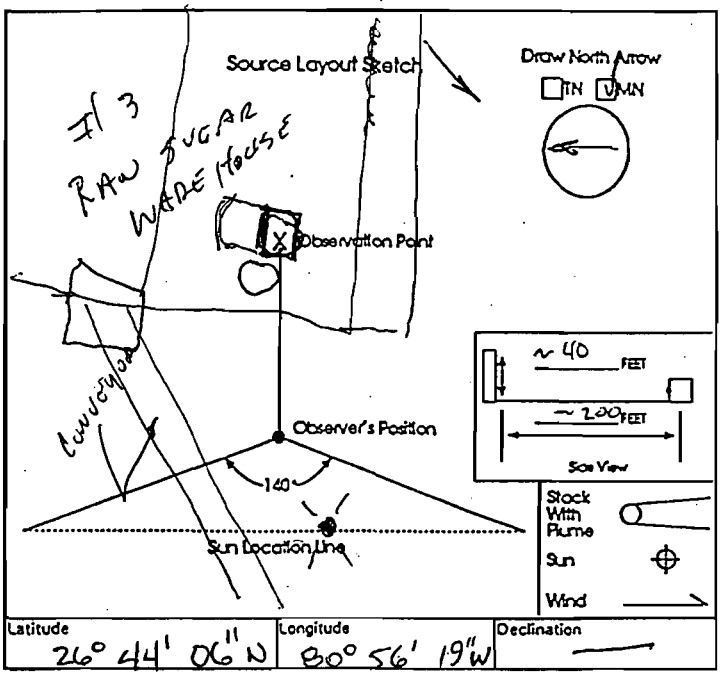
Emission Color: Start N/A End N/A | Water Droplet Plume: Attached ☐ Detached ☐ None ☑

Describe Plume Background: Start SKY End SKY

Background Color: Start BLUE/WHITE End B/W | Sky Conditions: Start BROKEN End BROKEN

Wind Speed: Start 5-15 End 5-15 | Wind Direction: Start NE End NE

Ambient Temp.: Start 78 End 78 | Wet Bulb Temp.: 67 | RH Percent: 56



Latitude: 26° 44' 06" N | Longitude: 80° 56' 19" W | Declination: —

Additional Information: 0510003-001-AC

Observation Date	Time Zone	Start Time	End Time
9 DEC 99	EAST	1547	1612

Sec / Min	0	15	30	45
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
11	0	0	0	0
12	0	0	0	0
13	0	0	0	0
14	0	0	0	0
15	0	0	0	0
16	0	0	0	0
17	0	0	0	0
18	0	0	0	0
19	0	0	0	0
20	0	0	0	0
21	0	0	0	0
22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28	0	0	0	0
29	0	0	0	0
30	0	0	0	0

Observer's Name (Print): MICHAEL J. ARRANTS

Observer's Signature: [signature] | Date: DEC 99

Organization: GOLDER ASSOCIATES INCORPORATED

Certified By: EASTERN TECH. ASSOCIATES | Date: 24 AUG 99

SOURCE TEST REPORT
FOR
PARTICULATE MATTER, VISIBLE EMISSIONS AND NON-METHANE VOLATILE ORGANIC COMPOUNDS EMISSIONS

GRANULAR CARBON REGENERATIVE FURNACE
WET SCRUBBER EXHAUST
CLEWISTON, FLORIDA

FDEP PERMIT NUMBER 051-0003-009-AC
PSD-FL-272

JANUARY 20, 2000

PREPARED FOR:

U.S. SUGAR CORPORATION
SOUTH W.C. OWEN AVENUE
CLEWISTON, FLORIDA 33440

PREPARED BY:

AIR CONSULTING AND ENGINEERING, INC.
2106 N.W. 67TH PLACE
GAINESVILLE, FLORIDA 32653
(352) 335-1889

238-00-04

2.0 SUMMARY AND DISCUSSION OF RESULTS

Table 1 is a summary of the emission results and flue gas parameters.

Particulate emissions averaged 0.538 pounds per hour (lbs/hr), which is within the allowable emission rate of 0.7 lbs/hr.

Non-methane volatile organic compounds averaged 0.320 lbs/hr as Carbon and 0.391 lbs/hr as Propane. According to permit conditions VOC emissions shall not exceed 1.0 lbs/hr as Propane.

Complete particulate emission summaries, field data sheets, and laboratory data and are presented in Appendices A, B, and C. Gaseous emission summaries and strip chart copies are enclosed in Appendix D.

The Sulfur content of the Number 2 distillate oil fired in the furnace is 0.05 % by weight, which is within the permitted standard of 0.05 % Sulfur content (see Appendix F for fuel analysis).

Visible emissions from the outlet averaged 10 percent opacity for the highest six minute period of the one-hour test. Permitted emissions are 10 percent opacity (see Appendix E for VE data sheet and observer's certification).

Complete emission summaries, field data sheets, and laboratory data are presented in Appendices A, B, and C.

A copy of the Granular Carbon Regenerative Furnace Log is provided in Appendix F.

Table 1. Particulate and VOC Emission Summary
Granular Carbon Regeneratitive Furnace Exhaust - Clewiston Mill
United States Sugar Corporation
Clewiston, Florida
January 20, 2000

Run Number	Time	Flow Rate dscfm	Particulate Emissions gr/dscf	Particulate Emissions lbs/hr	Non-Methane VOC Emissions as Carbon lbs/hr	Non-Methane VOC Emissions as Propane lbs/hr
1	0909-1011	5526	0.0109	0.5140	0.247	0.302
2	1055-1156	5561	0.0097	0.4640	0.273	0.334
3	1240-1341	4967	0.0149	0.6350	0.439	0.536
Average	—	5351	0.0118	0.5377	0.320	0.391

Allowable Emission:

PM = 0.7 lbs/hr
VOC = 1.0 lbs/hr

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Murray T. Brinson
Vice President
United State Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* | B. Date of Delivery

C. Signature

X Andrew Salis ☐ Agent ☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 1521

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

Article Sent To:
Mr. Murray T. Brinson

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

10/27/00
Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
United States Sugar Corp.
Street, Apt. No.; or PO Box No.
111 Ponce DeLeon Ave.
City, State, ZIP+4
Clewiston, FL 33440

PS Form 3800, July 1999 See Reverse for Instructions

7099 3400 0000 1453 1521

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 27, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Draft Permit No. 0510003-010-AC
Permit No. PSD-FL-272A
U.S. Sugar Clewiston Mill
Expansion of Boiler No. 4 and Refinery Operations, Revision

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,

for 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:
Mr. Murray T. Brinson, Vice President

Project No. 0510003-010-AC
PSD Permit No. PSD-FL-272A

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

Project: Expansion of Boiler No. 4 and Refinery Operations, Revision

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 purpose of this modification is to regain authorization to fire fuel oil containing up to 2.50% sulfur by weight in Boiler Nos. 1- 3. This authorization was lost in original Permit No. PSD-FL-272 because the Air Quality Analysis that provided the basis for issuance reflected a lower sulfur content and increased stack heights. These constraints were necessary because of modeled potential adverse impacts related to building downwash. However, the PSD permit allowed future modification to regain the higher sulfur fuel based on a revised Air Quality Analysis. The applicant has provided an Air Quality Analysis that demonstrates compliance with the Ambient Air Quality Standards and PSD increments. The analysis was based on the ISC PRIME model, which was approved by EPA Region 4 for use with this project. This non-guideline dispersion model was selected to better evaluate the downwash contributions related to the project. Also, construction was completed that raised the stacks for Boiler Nos. 1 – 3 to 213 feet in height. The Air Quality Analysis did include several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. These constraints are included in this modification as permit conditions. This project makes no new BACT determinations.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The 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.

for 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 _____ to the persons listed:

Mr. Murray T. Brinson, U.S. Sugar*
Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD
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.

Martha Jane Wise (Clerk) 10/27/00 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 051003-010-AC
Permit No. PSD-FL-272A

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 project restores authorization to fire fuel oil containing up to 2.5% sulfur by weight. This authorization was lost in original Permit No. PSD-FL-272 because the supporting Air Quality Analysis was based on increased stack heights and a lower fuel sulfur content for Boiler Nos. 1 – 3. During the summer, the stacks for Boiler Nos. 1 – 3 were raised to 213 feet in height. A revised Air Quality Analysis was performed based on the ISC PRIME dispersion model, taller stacks, and higher fuel sulfur content. The ISC PRIME model was used to better evaluate the contributions associated with stack downwash from the refinery building. Although the ISC PRIME model is a non-guideline model, it has been proposed by EPA as a replacement for ISCST3 and was approved by EPA Region 4 for use with this project. While the revised Air Quality Analysis demonstrates compliance with the Ambient Air Quality Standards and PSD increments, it included several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. These constraints are included as conditions in the Draft Permit. Because the original PSD permit allowed the permittee to regain use of the higher sulfur fuel, a determination of Best Available Control Technology (BACT) was not required.

An air quality impact analysis was conducted for the project. Emissions from the modified facility 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 NO_2, SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment Consumed ($\mu g/m^3$)		Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed
PM_{10}			
24-hour	26	31	84%
Annual	1	17	6%
SO_2			
3-hour	357	512	70%
24-hour	75	91	82%
Annual	13	20	65%
NOx			
Annual	4	25	16%

NO_2 and PM_{10} emissions from the project have no significant impact on the PSD Class I Everglades National Park. The maximum predicted PSD Class I SO_2 increments consumed in the Everglades National Park by all sources in the area, including this project, will be as follows:

PSD Class I Increment Consumed ($\mu g/m^3$)		Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed
SO_2			
3-hour	20	25	80%
24-hour	3	5	60%
Annual	0.33	2	7%

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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.

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
Hendry County

Facility I.D. No. 0510003
Emissions Units 001 through 026

Boiler No. 4 and Refinery Expansion
Revision Based on ISC PRIME Modeling Analysis

Project No. 0510003-010-AC
Permit No. PSD-FL-272A

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

October 26, 2000

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

- Received the PSD air pollution construction permit application on 01/06/00.
- Requested additional information on 02/04/00, 05/26/00, 06/21/00, and 10/11/00.
- Received written comments from EPA Region 4 on 02/04/00.
- Held teleconference on 06/28/00 with applicant, Department, and EPA Region 4.
- Received additional information on 05/04/00, 05/23/00, 09/11/00, and 10/19/00 (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 No. 2061, Raw Cane Sugar Processing
Industry No. 2062, Sugar Refining

2.4 Regulatory Categories

Power Plant Siting: power plant siting is not applicable to this facility.

Title III – HAP: Based on the most recent test data available for the industry, this facility is believed to be an existing major source of hazardous air pollutants.

Title IV - Acid Rain: This facility is not subject to the federal Acid Rain program.

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/PM10), 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 regulated 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 facility includes two fuel storage tanks subject only to the record keeping requirements of the federal New Source Performance Standards in 40 CFR 60, Subpart Kb. Boiler No. 7 is also subject to NSPS Subpart Db.

3.0 PROPOSED PROJECT

3.1 Project Description

In the application for Permit No. PSD-FL-272, the applicant requested 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. However, the modeling analysis indicated potential adverse ambient impacts related to stack downwash caused by the refinery building. To resolve the issues, the applicant submitted an Air Quality Analysis based on ISC PRIME, a non-guideline model, which requires approval by EPA. Review of the non-guideline model proved time consuming. Because of the impending sugarcane season, the applicant later submitted an alternate Air Quality Analysis based on a guideline model with a reduced fuel sulfur content for Boiler Nos. 1 - 3 and increased stack heights. This was done with the understanding that the original fuel sulfur limit (2.50% sulfur by weight) could be regained once the Air Quality Analysis based on the ISC PRIME model was approved and demonstrated compliance with the Ambient Air Quality Standards and the PSD increments. Permit No. PSD-FL-272 was issued accordingly and established emissions standards based on the Best Available Control Technologies (BACT) for CO, NOx, PM, PM10, SAM, SO_2, and VOC.

For the current project, the applicant submitted a request to regain the use of fuel oil for Boiler Nos. 1 - 3 that contains no more than 2.50% sulfur by weight. The supporting Air Quality Analysis was based on the ISC PRIME model, taller stacks for Boiler Nos. 1 - 3, and the higher sulfur fuel oil. EPA Region 4 approved the use of the ISC PRIME model for this project. Also, the stacks for Boiler Nos. 1 – 3 were raised during the summer to 213 feet in height. The Air Quality Analysis demonstrates compliance with the Ambient Air Quality Standards and the PSD increments. However, several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production were imposed for the modeling analysis.

3.2 Project Emissions

Provisions for making these modifications were provided for in Permit No. PSD-FL-272. Therefore, the project does not result in any net emissions increases.

4.0 RULE APPLICABILITY

4.1 PSD Review

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). 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 in 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. The second part requires an Air Quality Analysis consisting of the following: 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.

Previously issued Permit No. PSD-FL-272 established emissions standards based on the Best Available Control Technologies (BACT) for CO, NOx, PM, PM_{10}, SAM, SO_2, and VOC. Because this permit contemplated the applicant regaining the authorization to fire the higher sulfur fuel, this new project does not result in a net increase in emissions. Therefore, no new BACT determinations were necessary. Only issues regarding the revised Air Quality Analysis and constraints used in the modeling were reviewed for this modification.

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 62-296	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

5.0 AIR QUALITY IMPACT ANALYSIS

5.1 Introduction

The proposed project will increase PM_{10}, SO_2, NOx, CO, and VOC emissions at levels in excess of PSD significant amounts. PM_{10}, SO_2, and NOx 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, PM_{10}, and NO_2;
- An Ambient Air Quality Standards (AAQS) analysis for PM_{10}, SO_2, NO_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 stacks for Boiler Nos. 1 – 3 were 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.

5.2 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 MINIMIS 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	86	Yes	13
PM_{10}	24-hr	31	Yes	10
CO	8-hr	3,378	Yes	575
NO_2	Annual	2.1	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 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. In addition, even though preconstruction monitoring was not required for NO_2, a background concentration was required for use in the AAQS analysis for NO_2.

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	3,450
	1-hour	5,780
NO_2	Annual	23

5.3 Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS 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 Industrial Source Complex Short Term (ISCST3) model showed potential problems for SO_2 and PM_{10}. The applicant indicated that this was a result of deficiencies in the building downwash algorithm in the currently EPA-approved ISCST3 model. Therefore, the applicant requested the use of the ISC-PRIME model for predicting the air quality impacts of this project. This model better characterizes and defines building downwash and incorporates into the ISCST3 model the efforts of a program called the Plume RIse Model Enhancements (PRIME). ISC-PRIME has recently been proposed by EPA in the April 21, 2000 Federal Register as a replacement for the ISCST3 model. ISC-PRIME has yet to be promulgated for use, but is scheduled to be promulgated sometime next year at the end of the required comment period. However, EPA can approve the model for use on a case-by-case basis, and has approved ISC-PRIME for use in evaluating the air quality impacts of this particular project.

The ISC-PRIME 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 ISC-PRIME 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 ISC-PRIME 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 ISC-PRIME, 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.

ISC-PRIME was used to determine the predicted impacts of all area sources, including the project, in both the PSD Class II area in the vicinity of the facility and the PSD Class I Everglades National Park (ENP) 100 km to the south. In addition the California Puff (CALPUFF) long-range transport model was used to determine predicted maximum impacts from the project on the ENP. CALPUFF is a Lagrangian puff model that is recommended by EPA and the National Park Service for predicting the pollutant impacts at receptor distances beyond 50 km. For this project, CALPUFF was used with the South Florida CALMET wind field for the year 1990.

5.4 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 75 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 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	7	1	Yes	35
	24-hr	86	5	Yes	35
	3-hr	370	25	Yes	75
PM_{10}	Annual	3	1	Yes	12
	24-hr	31	5	Yes	12
CO	8-hr	3,378	500	Yes	20
	1-hr	7,545	2,000	Yes	20
NO_2	Annual	2	1	Yes	4

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	0.006	0.1	No
	24-hr	0.4	0.2	Yes
	3-hr	1.9	1.0	Yes
PM_{10}	Annual	0.003	0.2	No
	24-hr	0.2	0.3	No
NO_2	Annual	0.003	0.1	No

As shown in the tables the maximum predicted air quality impacts due to SO_2, PM_{10}, NO_2, 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}, NO_2, 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.

5.5 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}, NO_2, and CO analyses were: 35 km (annual and 24-hour) and 75 km (3-hour); 12 km (annual and 24-hour); 4 km (annual); and 20 km (8-hour and 1-hour), respectively.

5.6 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	1	No	17
	24-hr	26	No	31
SO_2	Annual	13	No	20
	24-hr	75	No	91
	3-hr	357	No	512
NO_2	Annual	4	No	25

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 ($\mu g/m^3$)
SO2	Annual	0.33	No	2
	24-hr	3	No	5
	3-hr	20	No	25

5.7 AAQS Analysis

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 ($\mu g/m^3$)
PM10	Annual	5	23	28	No	50
	24-hr	39	39	78	No	150
SO2	Annual	29	5	34	No	60
	24-hr	223	13	236	No	260
	3-hr	526	47	573	No	1,300
CO	8-hr	3,313	3,450	6,763	No	10,000
	1-hr	8,342	5,780	14,122	No	40,000
NO2	Annual	8	23	31	No	100

5.8 Additional Impacts Analysis

Impacts On Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM10, SO2, 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.

6.0 CONCLUSION

Based on a review of the complete PSD application, reasonable assurances provided by the applicant, the previously issued BACT determinations, 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 is the project engineer responsible for reviewing the application and drafting the permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality

(DRAFT)

PERMITTEE

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

Authorized Representative:
Murray T. Brinson, Vice President

Permit No.	0510003-010-AC
PSD No.	PSD-FL-272A
Project:	Boiler No 4 and Refinery Expansion, Revised
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 and the existing refinery operation, the installation of three new sugar conditioning silos, and the installation of additional powdered sugar/starch silos. The revised permit includes new conditions that reflect the air quality analysis based on the ISC PRIME model.

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	Summary of Previous BACT Determination
Appendix GC	General Permit Conditions
Appendix GCP	Good Combustion Practices Plan

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

Date: _____

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 4 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

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
001	Bagasse Boiler No. 1 with wet scrubber (255,000 pounds of steam per hour)
002	Bagasse Boiler No. 2 with wet scrubber (230,000 pounds of steam per hour)
003	Bagasse Boiler No. 3 with wet scrubber (130,000 pounds of steam per hour)
004	Bagasse Boiler No. 5 (inactive, permanently shut down)
005	Bagasse Boiler No. 6 (inactive, permanently shut down)
009	Bagasse Boiler No. 4 with wet scrubber (300,000 pounds of steam per hour)
014	Bagasse Boiler No. 7 with electrostatic precipitator (385,000 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
025	Common fuel storage tank for Boiler Nos. 1 - 3
026	NSPS fuel storage tank for Boiler No. 7

Project No. 0510003-009-AC (Permit No. PSD-FL-272): For the project, net emissions increases of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC were significant and the permit established emissions standards for these pollutants based on the Best Available Control Technology. Permit issuance was based on an Air Quality Analysis with ISCST3 modeling, increased stack heights for Boiler Nos. 1 – 3, and lower sulfur contents for Boiler Nos. 1 – 3. However, the permit allowed the facility to regain the higher sulfur content oil for use in Boiler Nos. 1 – 3 if a revised Air Quality Analysis demonstrated compliance with the AAQS and PSD increments.

Project No. 0510003-010-AC (Permit No. PSD-FL-272A): The permittee raised the stacks of Boiler Nos. 1-3 to 213 feet. A revised Air Quality Analysis based on the ISC PRIME model resolved the adverse ambient

impacts and demonstrated compliance with the AAQS and PSD increments. This model was able to evaluate ambient impact contributions resulting from downwash from each stack. EPA Region 4 approved the non-guideline model for use with this project. Although Boiler Nos. 1 - 3 regain the use of fuel oil containing no more than 2.5% sulfur by weight, additional constraints were used in the analysis, which are included as conditions in this permit.

REGULATORY CLASSIFICATION

HAPs: Based on the most recent information for bagasse-fired boilers, this facility is 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.

NSPS Sources: Fuel oil storage tanks (Emissions Unit Nos. 024 and 026) are subject to regulation under the New Source Performance Standards of 40 CFR 60, Subpart Kb.

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.

- EPA Region 4's approval on November 4, 1999 of the ISC Prime model for use with this project.
- Initial permit application received June 25, 1999, associated correspondence to make complete, and final permit issued on November 22, 1999.
- Permit application for revision received January 6, 2000 and associated correspondence to make complete.

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

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

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-210, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.). The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. Operation Permit Required: This permit authorizes modification of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. In accordance with Chapter 62-213, F.A.C. the permittee shall apply for a Title V operation permit on the appropriate application form with 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 No.	Emissions Unit Description
009	Boiler No. 4: 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.) 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 psig. The differential pressure drop across the wet scrubber is maintained between 8 and 11 inches of water column. Exhaust gases exit the wet scrubber at an average flow rate of 281,000 ACFM at 160° F. The stack is 150 feet high (GEP stack height is 225 feet high).

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

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

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

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

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

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

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

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

6. Fuel Oil: Any 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 from the dedicated storage tank. 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. Boiler No. 4 shall fire no more than 1500 gallons in any hour and no more than 500,000 gallons in any consecutive 12-month period. The permittee shall install, calibrate, operate, and maintain an individual fuel oil flow meter with integrator. Compliance with these limits shall be determined by the monitoring and record keeping requirements of this permit. [Applicant Request, Rule 62-210.200 (Definitions - PTE) and Rule 62-212.400 (BACT), F.A.C.]

7. Common Conditions: See Section III.B., "Common Conditions for Boiler Nos. 1 - 7" for other performance restrictions.

CONTROL EQUIPMENT AND TECHNIQUES

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

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

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

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

   The monitoring equipment shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations. The permittee shall read and record each scrubber parameter once

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

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

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

EMISSION LIMITING STANDARDS

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

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

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

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

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

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

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

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

    e. **Oil Firing**: The permittee shall record the oil-firing rate (gallons) for each 3-hour block of operation. In addition, the permittee shall calculate and record the oil-firing rate (gallons) for each 24-hour block of operation. Oil firing rates may be observed and recorded by hand or automated monitoring equipment.

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

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

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

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

    All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside

of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

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

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

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

B. EU 001, 002, 003, 004, 005, 009, and 014 - Common Conditions for Boiler Nos. 1 - 7

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

EU No.	Emissions Unit Description
001	Bagasse Boiler No. 1 with wet scrubber (255,000 pounds of steam per hour)
002	Bagasse Boiler No. 2 with wet scrubber (230,000 pounds of steam per hour)
003	Bagasse Boiler No. 3 with wet scrubber (130,000 pounds of steam per hour)
004	Bagasse Boiler No. 5 (inactive, permanently shut down)
005	Bagasse Boiler No. 6 (inactive, permanently shut down)
009	Bagasse Boiler No. 4 with wet scrubber (300,000 pounds of steam per hour)
014	Bagasse Boiler No. 7 with electrostatic precipitator (385,000 pounds of steam per hour)

The PSD permit for Boiler No. 4 (PSD-FL-272A) was issued based on an Air Quality Analysis using the ISC PRIME model that contained several operational constraints on existing emissions units. These constraints are now enforceable conditions of the permit and are in addition to any limits imposed by other valid permits. Modification of these constraints would require modification of the PSD permit and a new Air Quality Analysis.

PERFORMANCE RESTRICTIONS

1. Permanent Shutdown: Boiler Nos. 5 and 6 shall remain permanently shut down and rendered incapable of operation. These units are no longer available as "standby" units. Any proposed future operation of either boiler would require a preconstruction review permit as a "new" unit. [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

2. Modified Stack Heights: The stacks for Boiler Nos. 1, 2, and 3 shall be maintained at a minimum of 213 feet in height. [Design, Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

3. Crop Season: For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

4. Capacities: For each boiler, the maximum 1-hour operating capacities shall not exceed:

   a. **Boiler No. 1**: 255,000 pounds of steam per hour, 495 mmBTU per hour of total heat input, and 1500 gallons of oil per hour

   b. **Boiler No. 2**: 230,000 pounds of steam per hour, 447 mmBTU per hour of total heat input, and 1500 gallons of oil per hour

   c. **Boiler No. 3**: 130,000 pounds of steam per hour, 265 mmBTU per hour of total heat input, and 900 gallons of oil per hour

   d. **Boiler No. 4**: 300,000 pounds of steam per hour, 633 mmBTU per hour of total heat input, and 1500 gallons of oil per hour

   e. **Boiler No. 7**: 385,000 pounds of steam per hour, 812 mmBTU per hour of total heat input, and 1839 gallons of oil per hour

   {Permitting Note: No additional record keeping requirements are imposed by these conditions.}

   [Design, Supporting Air Quality Analysis for PSD-FL-272A]

5. Fuel Oil Sulfur Contents

   a. **Boiler Nos. 1 - 3, Crop Season**: From October through April of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 2.50% sulfur by weight.

   b. **Boiler Nos. 1 - 3, Off-Season**: From May through September of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 1.60% sulfur by weight. In April of each year, a composite sample from the common tank shall be taken and analyzed for the sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. If the sulfur content is higher than 1.60% sulfur by weight, the permittee shall purchase additional oil to blend down to the permit limit before any fuel from the common tank is authorized for firing during the off-season. An additional composite sample shall be taken from the common tank after blending and analyzed for the fuel sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. It is a violation of this permit to fire fuel from the common tank without filing a report with the Compliance Authority that demonstrates compliance with the lower fuel sulfur limit. Thereafter, only fuel oil containing no more than 1.60% sulfur by weight shall be purchased and added to the common tank during the off-season. It is the permittee's responsibility to appropriately plan for and stage fuel purchases to comply with this condition.

   c. **Boiler No. 4**: Any fuel oil fired in Boiler No. 4 shall contain no more than 0.70% sulfur by weight.

   d. **Boiler No. 7**: Any distillate oil fired in Boiler No. 7 shall contain no more than 0.05% sulfur by weight.

   The permittee shall maintain fuel records that indicate compliance with the above conditions for each fuel oil purchase at each tank. The sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. For each shipment, a certified analysis supplied by the fuel oil vendor is sufficient to demonstrate compliance.

   [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

6. Fuel Oil Consumption

   a. **Boiler Nos. 1 - 4, Crop Season**: From October through April of each year, the total fuel oil consumption for Boiler Nos. 1 - 4 shall not exceed 16,200 gallons during any 3-hour period and 88,800 gallons during any 24-hour period.

   b. **Boiler Nos. 1 - 4, Off-Season**: From May through September of each year, the total fuel oil consumption for Boiler Nos. 1 - 4 shall not exceed 11,700 gallons during any 3-hour period and 54,000 gallons during any 24-hour period.

   The permittee shall install, calibrate, operate, and maintain individual fuel oil flow meters with integrators.

   [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

7. Steam Production

   a. Crop Season and Off-Season

   (1) Boiler No. 4 shall not produce more than 6,840,000 pounds of steam during any 24-hour period.

   (2) Boiler No. 7 shall not produce more than 8,400,000 pounds of steam during any 24-hour period.

   b. Off-Season (May through September)

(1) Operation of Boiler No. 7 shall be maximized to the greatest extent possible before operating any of the other boilers during the off-season.

(2) For Boiler Nos. 1 - 4, no more than three of these boilers shall operate simultaneously.

(3) For Boiler Nos. 1 - 4, the total steam production shall not exceed 1,845,000 pounds of steam during any 3-hour period.

(4) For Boiler Nos. 1 - 4, the total steam production shall not exceed 10,800,000 pounds of steam during any 24-hour period.

The permittee shall install, calibrate, operate, and maintain equipment to continuously record the steam production rates. The permittee shall also install, calibrate, operate, and maintain a steam flow integrator to record the accumulated steam flow rate.

[Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

8. Modifications: A request to modify any of these conditions shall be accompanied by a revised Air Quality Analysis that demonstrates compliance with the Ambient Air Quality Standards and PSD increments for the revised conditions.

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

PERFORMANCE TESTING

9. SO_2 Tests: To validate the SO_2 emission factor for Boiler Nos. 1 - 3, the permittee shall conduct emissions performance tests in accordance with EPA Method 6 or 6C for at least one of these boilers when firing only bagasse. The initial test shall be conducted between October 1, 2000 and February 1, 2001. Thereafter, at least one of these boilers shall be tested within the 12-month period prior to renewal of the air operation permit. Tests need not be conducted on the same boiler. Based on the results of the performance tests, the Compliance Authority may require additional testing or an additional Air Quality Analysis.

{Permitting Note: The expected emission factor is 0.06 pounds of SO_2 per mmBTU when firing only bagasse. This is not a permit limit for Boiler Nos. 1 - 3. Performance tests, notifications, reports, etc., are subject to the requirements listed in Section III.G. of this permit.}

[Supporting Air Quality Analysis for PSD-FL-272A]

REPORTING AND RECORD KEEPING REQUIREMENTS

10. Steam Production

a. **Crop Season and Off-Season**: For each 24-hour block of operation, the permittee shall record the total steam production rates (pounds, each) for Boiler Nos. 4 and 7. The permittee shall calculate and record the 24-hour average steam production rate for these units based on the actual operating hours during the 24-hour period.

b. Off-Season

(1) From May through September, the permittee shall record the individual and total steam production rates (pounds) for Boiler Nos. 1 - 4 for each 3-hour block when three of the boilers are in operation.

(2) From May through September, the permittee shall record the individual and total steam production rates (pounds) for Boiler Nos. 1 - 4 for each 24-hour block of operation.

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

11. Fuel Oil Consumption: For Boiler Nos. 1 - 4, the permittee shall record the oil-firing rates (gallons) for each 3-hour block of operation. From this data, the permittee shall calculate and record the oil firing rates (gallons) for each 3-hour and each 24-hour block of combined operation for Boiler Nos. 1 - 4.

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

12. Fuel Sulfur Content: For each fuel oil delivery, the permittee shall record and retain the following: the date, identification of the tank, the gallons of fuel delivered, the fuel oil analysis including the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable. This condition applies to each tank supplying fuel to any boiler.

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

C. EU 024, 025, and 026 - Fuel Tanks for Boilers

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

EU No.	Emission Unit Description
024	NSPS fuel storage tank for Boiler No. 4: Tank with a storage capacity of 100,000 gallons of No. 6 fuel oil (or a superior grade) containing no more than 0.7% sulfur by weight. Constructed in 2000.
025	Common fuel storage tank for Boiler Nos. 1 – 3: Tank with a storage capacity of 600,000 gallons of No. 6 fuel oil (or a superior grade) containing no more than 2.50% sulfur by weight. Constructed prior to 1984.
026	NSPS fuel storage tank for Boiler No. 7: Tank with a storage capacity of 200,000 gallons of No. 2 distillate oil (or a superior grade) containing no more than 2.50% sulfur by weight. Constructed in 1996.

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

RULE APPLICABILITY

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

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

RECORD KEEPING REQUIREMENTS

3. Signs: The permittee shall clearly mark each tank with the following statements:
   a. "Tank for Boiler Nos. 1 -3: From October through April, only fuel oil containing 2.50% sulfur by weight or less may be added to and stored in this tank. From May through September, only fuel oil containing 1.60% sulfur by weight or less may be added to and stored in this tank."
   b. "Tank for Boiler No. 4: Only fuel oil containing 0.70% sulfur by weight or less may be added to and stored in this tank."
   c. "Tank for Boiler No. 7: Only distillate oil containing 0.05% sulfur by weight or less may be added to and stored in this tank."

4. Records: For EU 024 and 026, the permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(b)]

5. Record Retention: For EU 024 and 026, 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)]

D. EU 017 - Granular Carbon Regenerative Furnace

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

3. Allowable Fuel: Only No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner. The fuel sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. [Applicant Request; Rule 62-212.400(BACT), F.A.C.]

CONTROL EQUIPMENT

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

5. GCRF Wet Scrubber: The permittee shall install, operate, and maintain a wet venturi / tray scrubber system designed to control at least 97% of the maximum particulate emissions during regeneration of the

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

EMISSION LIMITING STANDARDS

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

E. EU 021 - Alcohol Emissions and EU 023 - Propane-Fired Sock Heaters

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

2. Allowable Fuel: Only commercially available propane shall be fired in the sock heaters. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.]
3. Visible Emissions: Visible emissions of 5% opacity or less from the sock heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are above 5% opacity, the permittee shall investigate the cause and take the necessary corrective actions. There is no initial or periodic testing required for this condition. [Rule 62-4.070(3), F.A.C.]
4. Alcohol Emissions: Alcohol usage from the sugar refinery shall not exceed 30,000 pounds per consecutive 12 months. Compliance shall be determined by the purchase records and the Material Data Safety Sheets (MSDS) for these products. The permittee shall calculate and record the alcohol emissions for submittal of the Annual Operating Report and at the request of the Department. [Applicant Request; Rule 62-212.400 (BACT), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

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

F. EU 015, 016, 018, 019, 020, AND 022 - MISCELLANEOUS PARTICULATE SOURCES

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

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

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

CONTROL EQUIPMENT AND TECHNIQUES

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

PERFORMANCE RESTRICTIONS

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

EMISSION LIMITING STANDARDS

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

EMISSION LIMITING AND PERFORMANCE STANDARDS

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

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

3. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants that cause or contribute to an objectionable odor. An objectionable odor is defined as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]

4. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department's district office and, if applicable, appropriate local program. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the permittee's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [Rule 62-4.130, F.A.C.]

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

6. Excess Emissions:

   (a) Excess emissions resulting from start-up, shutdown or malfunction of any emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

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

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

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

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

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

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

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

8. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the permittee, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

9. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

10. Calculation of Emission Rate: The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

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

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

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

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

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

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

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial performance tests for NSPS sources and at least 15 days prior to any other required tests. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the permittee. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the permittee of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

16. Records: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

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

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

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

20. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each permittee shall notify the Department or the appropriate local program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department. [Rule 62-210.700(6), F.A.C.]

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

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

The following table summarizes the BACT emissions standards and control technology established in initial Permit No. PSD-FL-272.

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
	Visible Emissions	VE < 20% opacity, except 40% for 2 min./hour
SO2 (SAM)	Fuel Oil Sulfur Limit	0.7% sulfur by weight
	Bagasse Firing	0.06 lb/mmBTU
VOC	Good Combustion Practices	0.50 lb/mmBTU, as propane
EU 024 - NSPS Fuel Storage Tank for Boiler No. 4 (Record Keeping Requirements Only)		
EU 017 - Granular Carbon Regenerative Furnace with Afterburner and Wet Scrubber		
PM/PM10	Controlled by Afterburner and Wet Scrubbing System	0.7 lb/hr
	Surrogate PM Standard	Visible emissions < 10% 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	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

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

G.13 This permit incorporates the following previously issued determinations:

(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.

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

NOx Controls

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

Miscellaneous

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

STARTUP AND SHUTDOWN PROCEDURE

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

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

Cold Startup (approximately 4 to 5 hours)

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

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

Hot Startup (approximately 1 hour)

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

Shutdown

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

Florida Department of Environmental Protection

Memorandum

TO: Clair Fancy, Bureau of Air Regulation

THRU: Al Linero, BAR - New Source Review Section — 10/27

FROM: Jeff Koerner, BAR - New Source Review Section

DATE: October 26, 2000

SUBJECT: Project No. 0510003-010-AC
Permit No. PSD-FL-272A
U.S. Sugar Clewiston Mill
Expansion of Boiler No. 4 and Refinery Operations, Revised

Attached for approval and signature is the Draft Permit package for the U.S. Sugar's Clewiston Mill and Refinery located in Hendry County that revises Permit No. PSD-FL-272 issued on November 19, 1999. The purpose of this modification is to regain authorization to fire fuel oil containing up to 2.50% sulfur by weight in Boiler Nos. 1- 3. This authorization was lost in original Permit No. PSD-FL-272 because the Air Quality Analysis that provided the basis for issuance reflected a lower sulfur content and increased stack heights. These constraints were necessary because of modeled potential adverse impacts related to building downwash. However, the PSD permit allowed future modification to regain the higher sulfur fuel based on a revised Air Quality Analysis.

The applicant provided an Air Quality Analysis based on the ISC PRIME model that demonstrates compliance with the Ambient Air Quality Standards and PSD increments. Although the ISC PRIME model is a non-guideline model, it has been proposed by EPA as a replacement for ISCST3 and was approved by EPA Region 4 for use with this project. This model was selected to better evaluate the stack downwash contributions related to the project. Also, construction was completed during the summer that raised the stacks for Boiler Nos. 1 – 3 to 213 feet in height. The Air Quality Analysis did include several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. These constraints were included in this permit modification as specific conditions. The revised Air Quality Analysis was reviewed and approved by staff meteorologist, Cleve Holladay. No new BACT determinations were made as a result of this project.

I recommend your approval and signature. Day 74 of the permit time clock is December 31, 2000.

Attachments

AAL/jfk

Department of Environmental Protection

Jeb Bush
Governor

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

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

Project No.	0510003-010-AC
Permit No.	PSD-FL-272A
ARMS ID No.	051-0003
SIC No.	2061, 2062

PROJECT DESCRIPTION

Original Permit No. PSD-FL-272 was issued on November 19, 1999 that allowed expansion of Boiler No. 4 and refinery operations for U.S. Sugar's Clewiston Mill and Refinery located in Hendry County. The purpose of this application to modify the PSD permit is to regain authorization to fire fuel oil containing up to 2.50% sulfur by weight in Boiler Nos. 1- 3. This authorization was lost in original Permit No. PSD-FL-272 because the Air Quality Analysis that provided the basis for issuance reflected a lower sulfur content and increased stack heights. These constraints were necessary because of modeled potential adverse impacts related to building downwash. However, the PSD permit allowed future modification to regain the higher sulfur fuel based on a revised Air Quality Analysis.

The applicant provided an Air Quality Analysis based on the ISC PRIME model that demonstrates compliance with the Ambient Air Quality Standards and PSD increments. Although the ISC PRIME model is a non-guideline model, it has been proposed by EPA as a replacement for ISCST3 and was approved by EPA Region 4 for use with this project. This dispersion model was selected to better evaluate the downwash contributions related to the project. Also, construction was completed during the summer that raised the stacks for Boiler Nos. 1 – 3 to 213 feet in height. The Air Quality Analysis did include several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. These constraints were included in this permit modification as specific conditions. The revised Air Quality Analysis was reviewed and approved by staff meteorologist, Cleve Holladay. Because the original PSD permit contemplated the facility regaining the use of the higher sulfur fuel oil, no new BACT determinations were made.

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, P.E.
Registration No. 49441

10-26-00
Date

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

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. William A. Raiola, V.P.
United States Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* | B. Date of Delivery 5-21-01

C. Signature
X Joseph Quintana ☐ Agent ☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7000 0600 0026 4129 9365

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7000 0600 0026 4129 9365

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

Postmark Here

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Mr. William A. Raiola, VP

Street, Apt. No., or PO Box No.
111 Ponce DeLeon Ave.

City, State, ZIP+4
Clewiston, FL 33440

PS Form 3800, February 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 15, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

William A. Raiola, Vice President
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Minor Revisions
Air Permit No. PSD-FL-272A
Boiler No. 4/Refinery Expansion
Palm Beach County, Florida

Re: U.S. Sugar's Clewiston Sugar Mill and Refinery
Boiler No. 4 and Refinery Expansion
Minor Revisions to Air Permit No. PSD-FL-272A

Dear Mr. Raiola:

On April 26, 2001, the Department received a request from Golder Associates on behalf of U.S. Sugar to make minor revisions to Air Permit No. PSD-FL-272A for boiler No. 4 at the Clewiston sugar mill and refinery. The Department disagrees that it is burdensome and impractical to sample and analyze the fuel oil for sulfur content prior to off-season operation. This condition was not changed. In response to the request, the Department corrected a typographical error on page 10 of the permit and made minor revisions to Appendix GCP regarding the startup and shutdown procedures. These revisions are considered minor and no public notice is required. The revisions are attached and can be inserted directly into the original permit.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

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 (F.S.). 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 (14) 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), F.S., must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code (F.A.C.)

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, F.A.C.

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.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing

of a petition or a request for extension of time, this action will not be effective until further order of the Department.

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

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/18/01 to the person(s) listed:

Mr. William A. Raiola, USSC*
Mr. Dave Buff, Golder Associates
Mr. Ron Blackburn, SD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Charlotte J. Hayes (Clerk) 5/18/01 (Date)

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

b. **Steam Parameters**: The steam pressure (psig), steam temperature (°F), and steam production rate (pounds per hour) shall be continuously recorded with a chart recorder. *{Revised May 2001}*

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

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

e. **Oil Firing**: The permittee shall record the oil-firing rate (gallons) for each 3-hour block of operation. In addition, the permittee shall calculate and record the oil-firing rate (gallons) for each 24-hour block of operation. Oil firing rates may be observed and recorded by hand or automated monitoring equipment.

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

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

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

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

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

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

GOOD COMBUSTION PRACTICES

The following procedures are based upon U.S. Sugar's most recent submittal received by the Department in January of 2001.

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 ductwork, 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 (including oxygen and carbon monoxide process monitors) 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 includes instruction for observing the oxygen and carbon monoxide process monitors to promote good combustion as well as adjusting operations in response to an alarm condition. 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. Process monitors will be installed to monitor the oxygen (O2) content and the carbon monoxide (CO) content of the boiler flue gas. The instrument readouts 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 O2 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 oxygen process monitor will include an alarm with a set point at 1.5% (minimum) flue gas oxygen content based on a 1-hour block average. The CO process monitor will include an alarm with a set point at 3000 ppm (maximum) flue gas CO concentration based on a 1-hour block average. Each monitor will display both the instantaneous and the 1-hour block average. If the alarm is tripped for either process monitor (low oxygen content or high CO concentration), the boiler operator shall take corrective actions consistent with good combustion practices. Corrective actions may include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, firing some fuel oil in place of bagasse. For each such incident, the operator will summarize the corrective actions taken and the approximate time when operation within the target parameter(s) was regained.

NOx Controls

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

Miscellaneous

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

STARTUP AND SHUTDOWN PROCEDURES *(Revised May 2001)*

U.S. Sugar submitted the following procedures in April of 2001 to supplement the original PSD application for this project.

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

Cold Startup

1. Turn on water valves to scrubber spray nozzles to start scrubber.

2. Feed solid fuel into boiler combustion chamber.
3. Start fire in combustion chamber using a propane torch designed for that purpose.
4. As boiler heats up and starts to make steam, continuously observe the boiler and scrubber water levels, and stack plume.
5. Light a fuel oil burner at the lowest rate, continue to observe the stack plume and adjust, if necessary, by adjusting fuel, atomizing steam, and air to obtain proper combustion.
6. 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.
7. 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.
8. A cold startup is a startup after the boiler has been down for more than 4 or 5 hours. Typically, a cold startup will require 6 to 12 hours from the first fire to normal working pressure. There may be 10 cold startups per crop season (more or less) depending on excessive rain and mechanical breakdowns.

Hot Startup

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on water valves to scrubber spray nozzles to start scrubber.
3. Check the boiler and scrubber water levels, circulating pump and spray nozzles, and make sure they are functioning properly.
4. Light a burner. Continue to observe the stack plume, water levels, and burners.
5. 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.
6. 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.
7. A warm startup is a startup after the boiler has been down for less than 5 hours. Usually, the longer the boiler is down means a longer period will be needed for warm startup. Typically, a warm startup requires 1 to 5 hours depending on boiler operating conditions. There may be 5 cold startups per crop season (more or less) depending on mechanical breakdowns mill interruptions.

Shutdown

1. Stop fuel flow to the boiler. Reduce the forced draft, distributor air, overfire air, and induced forced draft.
2. Continue to observe the stack plume and water levels and make adjustments to maintain safe and optimum operating conditions.
3. The scrubber is turned off after the fire in the boiler is extinguished.

Memorandum

Florida Department of
Environmental Protection

BAR

TO: Howard Rhodes

THRU: ~~Clair Fancy~~ by ray
Al Linero

FROM: Jeff Koerner JK

DATE: May 15, 2001

SUBJECT: Minor Revisions to Air Permit PSD-FL-272A
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Original Project to Expand Operation of Boiler No. 4 and Refinery

Attached for your approval and signature are minor revisions to the previously issued PSD permit to expand operation of Boiler No. 4 and the refinery at U.S. Sugar's Clewiston sugar mill located in Hendry County. U.S. Sugar requested three changes: correction of a typographical error; minor revisions to the startup and shutdown procedures listed in Appendix GCP; and removal of the requirement to sample and analyze the fuel oil for Boiler No. 4 prior to the off-season. The first two requested changes were approved, but the third was denied. U.S. Sugar believes that it is burdensome and impractical to perform the required fuel sulfur analysis once per year. This requirement was included because U.S. Sugar opted to reduce the maximum sulfur content of the fuel oil from 2.5% sulfur by weight (crop season) to 1.6% sulfur by weight (off-season) due to problems with modeled SO_2 ambient impacts during the off-season. I believe that the fuel sulfur analysis is reasonable and necessary to ensure compliance.

I recommend your approval and signature.

Attachments

CHF/AAL/jfk

Memorandum

Florida Department of
Environmental Protection

BAR

TO: Howard Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: March 6, 2001

SUBJECT: Final Permit No. 0510003-010-AC (PSD-FL-272A)
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Boiler No. 4 Modification (ISC Prime)

The Final Permit is attached for your approval and signature to modify operations of U.S. Sugar's Boiler No. 4 at the existing Clewiston sugar mill and refinery located in Hendry County. The purpose of this modification is to regain authorization for Boiler Nos. 1- 3 to fire fuel oil containing up to 2.50% sulfur by weight. This authorization was removed in Permit No. PSD-FL-272 because the applicant based the Air Quality Analysis on a lower sulfur content and increased stack heights. These constraints were necessary because of modeled potential adverse impacts related to downwash from the refinery buildings. However, the PSD permit allowed future modification to regain the higher sulfur fuel for Boiler Nos. 1- 3 based on a revised Air Quality Analysis.

During the summer of 2000, construction was completed that raised the stacks for Boiler Nos. 1 – 3 to 213 feet in height. The applicant provided an Air Quality Analysis based on the ISC PRIME model that demonstrates compliance with the Ambient Air Quality Standards and PSD increments. The Air Quality Analysis did include several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. These constraints were included in this permit modification as specific conditions. No new BACT determinations were made as a result of this project.

The Public Notice of Intent to Issue was published in The Clewiston News on December 27, 2000 and proof of publication provided to the Department on January 4, 2001. No comments on the Draft Permit were received from the public, the South District Office, EPA Region 4, or the NPS. The applicant submitted comments that resulted in minor changes to the Final Permit, as summarized in the attached Final Determination. In addition, the applicant requested clarification on two issues related to the Clewiston facility: finishing the installation of previously permitted vacuum pan No. 7; and specific alarm set points for minimum flue gas oxygen content and maximum flue gas carbon monoxide content based on recent test data. After much discussion, agreement was reached and minor changes were also included in the final permit. Resolution of these two issues delayed issuance of the final permit.

Day 90 for this project is April 8, 2001. I recommend your approval and signature.

Attachments

CHF/AAL/jfk

Golder Associates Inc.

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

April 25, 2001

0037629

RECEIVED
APR 26 2001
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention : Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
FINAL PERMIT NO. 0510003-010-AC; PSD-FL-272A

Dear Mr. Koerner:

In follow-up to our recent telephone conversations, United States Sugar Corporation (U.S. Sugar) is requesting some revisions to the final air construction permit for Boiler No. 4, which was issued on March 8, 2001. The requested revisions are described below.

Page 10 of 25
Condition 22.b. Please revise the first occurrence of "steam temperature" to "steam pressure (psig)".

Page 13 of 25
Condition 5.b. U. S. Sugar considers this condition to be very burdensome and may prove to be unworkable. It requires a fuel oil sample to be taken each April, analyzed, and the results reported within 5 days to FDEP. If the sulfur content exceeds 1.6%, U. S. Sugar must order additional lower sulfur oil and add it to the tank prior to the off-season operation. U. S. Sugar must therefore try to estimate the amount of lower sulfur oil required in order to render the blended fuel no more than 1.6% sulfur. A second sample must then be taken and analyzed, and more lower sulfur fuel added if the blended fuel is still above 1.6% sulfur. This process would go on until the sulfur content is less than 1.6%. This all must be done prior to firing any fuel from the tank in the off-season.

Due to the burdensome and impractical nature of this requirement, U. S. Sugar desires the option to burn 1.6% sulfur (max) year-around, in order to avoid the sampling and analysis requirements. Under this option, an initial fuel oil sample will be obtained which demonstrates that the tank currently contains less than 1.6% sulfur fuel oil. Subsequent to this demonstration, U. S. Sugar would purchase only fuel oil for the tank which contains no more than 1.6% sulfur, and fuel receipts would be used to demonstrate compliance on an on-going basis. If fuel oil with greater than 1.6% sulfur is purchased for the tank, then the requirement as currently written will be complied with. It is noted that currently, compliance with all fuel oil sulfur content limits at the Clewiston mill is demonstrated through fuel oil receipts. Suggested wording for the revised condition is as follows:

> **Boiler Nos. 1 - 3, Off-Season**:
>
> From May through September of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 1.60% sulfur by weight.

(1) During any crop season (October through April of any year), if the permittee elects to fire fuel oil in Boiler Nos. 1-3 containing more than 1.6% sulfur, the following requirements will apply. In April of each year, a composite sample from the common tank shall be taken and analyzed for sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. If the sulfur content is higher than 1.60% sulfur by weight, the permittee shall purchase additional oil to blend down to the permit limit before any fuel from the common tank is authorized for firing during the off-season. An additional composite sample shall be taken from the common tank after blending and analyzed for the fuel sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. It is a violation of this permit to fire fuel from the common tank without filing a report with the Compliance Authority that demonstrates compliance with the lower fuel sulfur limit. Thereafter, only fuel oil containing no more than 1.60% sulfur by weight shall be purchased and added to the common tank during the off-season. It is the permittee's responsibility to appropriately plan for and stage fuel purchases to comply with this condition.

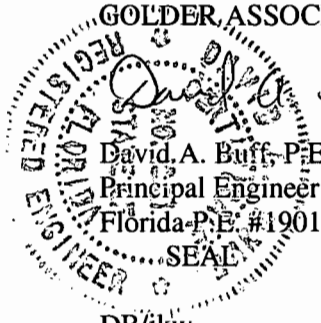
(2) If the permittee elects to fire only fuel oil in Boiler Nos. 1-3 containing a maximum of 1.6% sulfur throughout the entire year, the following requirements will apply. The permittee must obtain an initial composite sample from the common tank and analyze the sample for sulfur content. The results must demonstrate that the tank contains fuel oil with no greater than 1.6% sulfur. Within 5 days of obtaining the results of the fuel analysis, a report of the fuel sulfur content shall be submitted to the Compliance Authority. Thereafter, no further sampling and analysis of the common tank is required, provided the permittee maintains fuel oil receipts to demonstrate compliance with the 1.6% sulfur limitation.

Appendix GCP
As previously discussed, the final Title V permit for Clewiston dated February 19, 2001, incorporates revised Boiler No. 4 startup procedures (dated 8/25/00). Attached is a slightly corrected version that identifies when the wet scrubber is turned on. Please incorporate these into the new Boiler No. 4 permit.

Thank you for consideration of these additional comments. Please call or e-mail me if you have any additional questions concerning this information.

Sincerely,

GOLDER ASSOCIATES INC.



David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P.E. #19011
SEAL

DB/jkw
Attachments
cc: Don Griffin

CLEWISTON BOILER NO. 4

PROCEDURES FOR STARTUP AND SHUTDOWN

(Revised 01/31/01)

Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions are taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 4. Boiler room foreman and operating personnel have received proper training on emissions control procedures.

Cold Startup (approximately 6 to 12 hours)

1. Turn on water valves to scrubber spray nozzles to start scrubber.
2. Feed solid fuel into boiler combustion chamber.
3. Start fire in combustion chamber using a propane torch designed for that purpose.
4. As boiler heats up and starts to make steam, continuously observe the boiler and scrubber water levels, and stack plume.
5. Light a fuel oil burner at the lowest rate, continue to observe the stack plume and adjust if necessary, by adjusting fuel, atomizing steam, and air to obtain proper combustion.
6. 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 until burners can be turned off.
7. Continue to observe the stack plume, the scrubber water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain optimum operating conditions.
8. Normally, a cold startup will require 6 to 12 hours from the first fire to normal working pressure.

Hot Startup (approximately 1 to 5 hours)

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on water valves to scrubber spray nozzles to start scrubber.
3. Check the boiler and scrubber water levels, circulating pump and spray nozzles, and make sure they are functioning properly.

4. Light a burner, continue to observe the stack plume, water levels, and burners.

5. As the carbonaceous fuel fire gets hot enough to meet steam demand, reduce the burner fuel until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.

6. Continue to observe the stack plume, scrubber water level, and carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain optimum operating conditions.

7. Normally, a warm startup requires 1 to 5 hours, depending on boiler operating conditions.

Shutdown

1. Stop fuel flow to the boiler, reduce forced draft, distributor air, overfire air, and induced draft.

2. Continue to observe the stack plume and water levels and make adjustments to maintain safe and optimum operating conditions.

3. The scrubber is turned off after the fire in the boiler is extinguished.

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

William A. Raiola, VP
United States Sugar Corporation
111 Ponce DeLeon Ave.
Clewiston, FL 33440

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* | B. Date of Delivery: 3/15/01

C. Signature: X Andrea Sales ☐ Agent ☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 2320

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 2320

Article Sent To: William A. Raiola

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

Postmark Here

Name *(Please Print Clearly)* (to be completed by mailer)
U.S. Sugar Corp.
Street, Apt. No., or PO Box No.
111 Ponce DeLeon Ave.
City, State, ZIP+4
Clewiston, Fl 33440

PS Form 3800, July 1999 See Reverse for Instructions

Golder Associates Inc.

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

Golder Associates

January 29, 2001

RECEIVED
JAN 30 2001
BUREAU OF AIR REGULATION

0037629

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention : Jeffery Koerner, P.E.

RE: United States Sugar Corporation (U.S. Sugar) – PSD Permit Application for Boiler No. 4 and the Sugar Refinery at the Clewiston Mill
Draft Permit No. 0510003-010-AC; PSD-FL-272A

Dear Mr. Koerner:

United States Sugar Corporation (U.S. Sugar) has received and commented on the draft permit for the above referenced project issued by the Florida Department of Environmental Protection. Based on our subsequent discussions on the draft permit, the following clarifications to our previous comment letter are provided.

Page 6 of 25
In regards to Condition 8.c., U. S. Sugar does not wish to make any changes to the current wording of this condition related to the minimum scrubber water flow rate.

Page 14 of 25
Condition 7.b(1): Based on our discussions, the wording in the draft permit regarding Boiler No. 7 operation during the off-season will be revised to read as follows:

> "Operation of Boiler No. 7 shall be operated to the greatest extent possible during the off-season, taking into account operating efficiency, steam demands, and boiler availability due to maintenance."

Your concern over U. S. Sugar's intentions is acknowledged. It is U. S. Sugar's intention to use Boiler No. 7 during the off-season whenever the boiler is available and steam demands are sufficient, since it is a more efficient boiler. However, at lower steam demands during the off-season, when only the sugar refinery is operating, steam needs may not be great enough to justify using Boiler No. 7 (i.e., steam demand is less than about 75 percent of Boiler No. 7 design rate).

Page 21 of 25
As described in our November 17th submittal, refinery sources S-13, S-14 and S-15 (three sugar silos) and S-16 (powdered sugar/starch bins) have not yet been constructed. The current schedule is that construction would begin on these sources within the next two years. These are very small sources of PM/PM10 emissions, amounting to a total of 1.33 TPY. It is requested that the construction permit be extended for these sources to allow construction of these sources under this new schedule.

Thank you for consideration of these additional comments. Please call or e-mail me if you have any additional questions concerning this information.

Sincerely,
Golder Associates Inc.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P.E. #19011
SEAL

DB/arz

Attachments

cc: Don Griffin
Bill Wehrum
C. Holladay
D. Knowles, SD
EPA
NPS

UNITED STATES SUGAR CORPORATION

Post Office Box 1207 • Clewiston, Florida 33440-1207
Telephone 941/983-8121

January 3, 2001

RECEIVED
JAN 04 2001
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive
Suite 4
Tallahassee, Florida 32301

RE: United States Sugar Corporation, Clewiston Sugar Mill, Hendry County
Draft Permit Modifications No. 051-003-010-AC and No: PSD-FL-272A)
Extension of Operating Season for Bagasse Boiler No. 4

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

Gentlemen:

We are enclosing the Affidavit of Publication certifying that the "Public Notice of Intent to Issue Air Construction Permit " was duly published in the legal section of the December 27, 2000 issue of *THE CLEWISTON NEWS*.

Sincerely,

UNITED STATES SUGAR CORPORATION

Donald Griffin
Project Manager, Specialty Sugar

DG:kcb
Enclosure
cc: South Florida District, FDEP
David Buff, Golder Associates
William A. Raiola, USSC
Tony Yacaman, USSC
Lisa Gefen, USSC
Peter Briggs, USSC
J. Kaerner
C. Halladay
EPA
NPS

The Clewiston News

Published Weekly Clewiston, Florida

AFFIDAVIT OF PUBLICATION

State of Florida
County of Hendry

Before the undersigned authority, personally appeared Katrina Elsken, who on oath says she is the Executive Editor of the Clewiston News, a weekly newspaper published at Clewiston in Hendry County, Florida, that the attached copy of advertisement, being a

Public Notice in

the matter of Intent to Issue Air Construction Permit. DEP File No. 051003-010-AC Permit No. PSD-FL-272A in the

court, was published in

said newspaper in the issues of December 27, 2000

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

Katrina Elsken

Sworn to and subscribed before me this 27th day of December, A.D. 20 00.

Tiffany Koon
Notary Public

TIFFANY KOON
Notary Public - State of Florida
My Commission Expires Jun 25, 2004
Commission # CC948508

Lyons Printing

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 051003-010-AC
Permit NO. PSD-FL-272A

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 project restores authorization to fire fuel oil containing up to 2.5% sulfur by weight. This authorization was lost in original Permit No. PSD-FL-272 because the supporting Air Quality Analysis was based on increased stack heights and a lower fuel sulfur content for Boiler Nos. 1-3. During the summer, the stacks for Boiler Nos. 1-3 were raised to 213 feet in height. A revised Air Quality Analysis was performed based on the ISC PRIME dispersion model, taller stacks, and higher fuel sulfur content. The ISC PRIME model was used to better evaluate the contributions associated with stack downwash from the refinery building. Although the ISC PRIME model is a non-guideline model, it has been proposed by EPA as a replacement for ISCST3 and was approved by EPA Region 4 for use with this project. While the revised Air Quality Analysis demonstrates compliance with the Ambient Air Quality Standards and PSD increments, it included several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. Theses constraints are included as conditions in the Draft Permit. Because the original PSD permit allowed the permittee to regain use of the higher sulfur fuel, a determination of Best Available Control Technology (BACT) was not required.

An air quality impact analysis was conducted for the project. Emissions from the modified facility 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 NO_x, SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment	Consumed (ug/m³)	Allowable Increment (ug/m³)	Percent Increment Consumed
PM_{10}			
24-hour	26	31	84%
Annual	1	17	6%
SO_2			
3-hour	357	512	70%
24-hour	75	91	82%
Annual	13	20	65%
NO_x			
Annual	4	25	16%

NO_2 and PM_{10} emissions from the project have no significant impact on the PSD Class I Everglades National Park. The maximum predicted PSD Class I SO2 increments consumed in the Everglades National Park by all sources in the area, including this project, will be as follows:

PSD Class II Increment	Consumed (ug/m³)	Allowable Increment (ug/m³)	Percent Increment Consumed
SO_2			
3-hour	20	25	80%
24-hour	3	5	60%
Annual	0.33	2	7%

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 Rd, 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 petitions 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 specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statues 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.

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.

Golder Associates Inc.

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

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OCT 23 2000
BUREAU OF AIR REGULATION

October 19, 2000

0037504

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

ATTN: Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
REVISED ISC-PRIME MODELING SCENARIO
REQUEST FOR ADDITIONAL INFORMATION NO. 3

Dear Mr. Koerner:

United States Sugar Corporation (U.S. Sugar) has received the Florida Department of Environmental Protection's (FDEP) letter dated October 11, 2000, requesting additional information in regards to the revised ISC-PRIME modeling scenario for the Clewiston mill. Revised modeling scenario results were submitted to the FDEP in a letter from Golder Associates Inc. dated September 8, 2000. The purpose of this letter is to address the questions in the FDEP's letter to address all outstanding issues. The comments are addressed below, in the same order as they appear in the comment letter.

1. It is our understanding that, while EPA must approve use of the ISC-PRIME model, the FDEP approves the actual modeling analysis and results, under delegation from the EPA. EPA approved the use of the ISC-PRIME model for the Clewiston mill on November 4, 1999.

2. The following provides a description of each of the four SO_2 emission tables for the Clewiston mill.

Table 3 HR CROP

CASE A: MAXIMUM HEAT INPUT

- All boilers (Nos. 1, 2, 3, 4, and 7) operating at maximum permitted capacity (i.e., 100-percent capacity).
- Boiler Nos. 1, 2, and 3 are burning the maximum amount of fuel oil possible with 2.5-percent sulfur.
- Boiler No. 4 is burning the maximum amount of fuel oil permitted to be burned with 0.7-percent sulfur (from a separate fuel oil tank).
- Boiler No. 7 is burning 100-percent bagasse, which results in higher SO_2 emissions than burning 0.05-percent sulfur fuel oil.

- This fuel oil burning scenario is consistent with the 3-hour No. 6 fuel oil consumption limitation total for Boiler Nos. 1, 2, 3, and 4 of 16,200 gallons per 3-hr period.
- All stack flow rates and velocities representative of 100-percent load conditions.

CASE B: 80 PERCENT OF MAXIMUM HEAT INPUT

- The same assumptions as Case A, except total steam rate and heat input rate for each boiler is reduced to 80 percent of maximum (80-percent load). Fuel oil burning in all boilers remains as in Case A. Therefore, total SO_2 emissions due to fuel oil burning remain the same as in Case A, but SO_2 due to bagasse burning is reduced.
- Stack flow rate and velocity for each boiler is reduced by 20 percent compared to Case A.

NOTE: For Boiler No. 4, its permit limits maximum fuel oil usage to 1,500 gal/hr. For 0.7-percent oil, the heating value is 142,000 Btu/gal, resulting in a heat input of only 213 MMBtu/hr, as opposed to a heat input of 225.1 MMBtu/hr if higher sulfur No. 6 fuel oil was being burned. The footnotes at the bottom of all four SO_2 emission tables have been corrected to reflect this.

Table 24 HR CROP

CASE A: MAXIMUM HEAT INPUT w/BOILERS 1-3 FIRING OIL

- All boilers (Nos. 1, 2, 3, 4, and 7) operating at their maximum 24-hour capacity. Note that for Boiler Nos. 4 and 7, permit limitations restrict the 24-hour steam production and heat input rates to less than the rates used for the 3-hour scenario.
- Total No. 6 fuel oil consumption or Boiler Nos. 1-4 is limited to 88,800 gallons per 24-hour period, equivalent to 3,700 gal/hr. This total fuel oil consumption was apportioned to Boiler Nos. 1-3, since they burn 2.5-percent sulfur oil, compared to 0.7-percent sulfur oil in Boiler No. 4. First, Boiler No. 3 was apportioned 900 gal/hr, based on its maximum oil firing capability, and because of its lower stack velocity and since Boiler Nos. 1-3 stacks will be raised to the same height of 213 feet. The remaining fuel oil usage was divided equally between Boiler Nos. 1 and 2 (1,400 gal/hr each).
- Boiler No. 4 burning 100-percent bagasse.
- Boiler No. 7 burning 100-percent bagasse, which results in higher SO_2 emissions than burning 0.05-percent sulfur fuel oil.
- Stack flow rate and velocity for each boiler reflective of its heat input.

CASE B: MAXIMUM HEAT INPUT w/BOILERS 1-4 FIRING OIL

- Same as Case A, except that total oil firing (3,700 gal/hr) was distributed approximately equally (based on heat input from oil) among all four boilers.

CASE C: 80 PERCENT OF MAXIMUM HEAT INPUT WITH BOILERS 1-3 FIRING OIL

- The same assumptions as Case A, except total steam rate and heat input rate for each boiler is reduced to 80 percent of Case A (80-percent load). Fuel oil burning in all boilers remains as in Case A. Therefore, total SO_2 emissions due to fuel oil burning remain the same as in Case A, but SO_2 due to bagasse burning is reduced.
- Stack flow rate and velocity for each boiler is reduced by 20 percent compared to Case A.

CASE D: 80 PERCENT OF MAXIMUM HEAT INPUT w/BOILERS 1-4 FIRING OIL

- The same assumptions as Case B, except total steam rate and heat input rate for each boiler is reduced to 80 percent of Case B (80-percent load). Fuel oil burning in all boilers remains as in Case B. Therefore, total SO_2 emissions due to fuel oil burning remain the same as in Case B, but SO_2 due to bagasse burning is reduced.
- Stack flow rate and velocity for each boiler is reduced by 20 percent compared to Case B.

3 HR OFFCROP

CASE A (3-hr)

- Total steam production from all boilers (Nos. 1, 2, 3, 4, and 7) is limited to 1,000,000 lb/hr steam (3-hr avg.).
- Total steam production from Boiler Nos. 1-4 is limited to 615,000 lb/hr (3-hr avg.). The 615,000 lb/hr steam limitation also represents the maximum steam rates for Boiler Nos. 1-3 combined.
- For Boiler Nos. 1-4, only three of these boilers will operate at any one time.
- Boiler Nos. 1, 2 and 3 burning the maximum amount of fuel oil they can burn, with 1.6-percent sulfur.
- Boiler No. 4 is not operating.
- Boiler No. 7 burning 100-percent bagasse, which results in higher SO_2 emissions than burning 0.05-percent sulfur fuel oil.
- This fuel oil burning scenario is consistent with the proposed 3-hour off-crop No. 6 fuel oil consumption limitation total for Boiler Nos. 1-4 of 11,700 gallons per 3-hr period.

CASE B (3-HR)

- Same as Case A, except that Boiler No. 4 is operating at maximum instead of Boiler No. 1, and Boiler Nos. 2 and 3 are operating at slightly reduced rates. Stack velocities are adjusted accordingly.

24 HR OFFCROP

Note: Cases A-C all result in the maximum SO_2 emissions for the 24-hr averaging period, i.e., some combination of Boiler Nos. 1-3 operating to produce 450,000 lb/hr steam (24-hr avg.) while burning a combined 54,000

gal/day of 1.6-percent sulfur, with Boiler No. 4 shutdown. Cases D and E reflect some combination of Boiler Nos. 2-4 operating to produce 450,000 lb/hr steam, with significant oil burning in Boiler No. 4 at 0.7-percent sulfur. All cases reflect Boiler No. 7 operating at maximum.

CASE A (24-HR)

- Total steam production from all boilers (Nos. 1, 2, 3, 4, and 7) is limited to 800,000 lb/hr steam (24-hr average).
- Total steam production from Boiler Nos. 1-4 is limited to 450,000 lb/hr steam (24-hr average).
- For Boiler Nos. 1-4, only three of these boilers will operate at any one time.
- To achieve the 450,000 lb/hr steam from Boiler Nos. 1-4, for this scenario Boiler No. 1 is operating at maximum, and Boiler No. 2 is operating at about 93 percent of maximum. Boiler Nos. 3 and 4 are not operating.
- Boiler Nos. 1 and 2 are burning fuel oil with 1.6-percent sulfur.
- Boiler No. 7 is burning 100-percent bagasse.
- This fuel oil burning scenario is consistent with the proposed off-crop No. 6 fuel oil consumption limitation total for Boiler Nos. 1-4 of 54,000 gallons per 24-hr period (2,250 gal/hr). Total No. 6 fuel oil consumption (total of Boiler Nos. 1, 2, 3 and 4) is limited to 54,000 gallons per 24 period.

CASE B (24-HR)

- Same as Case A, except that Boiler No. 3 is operating at maximum steam rate and Boiler Nos. 1 and 2 are operating at about 60-percent load to make up the remainder of the 450,000 lb/hr steam. Boiler No. 3 is burning the maximum amount of oil (900 gal/hr), while Boiler Nos. 1 and 2 are burning 675 gal/hr oil each to make up the remainder of the total 2,250 gal/hr. Boiler No. 4 is not operating. Stack velocities are adjusted accordingly.

CASE C (24-HR)

- Same as Case B, except Boiler Nos. 1-3 are each operating at about 70-percent load for a total of 450,000 lb/hr steam.

CASE D (24-HR)

- Same as Case A, except that Boiler No. 1 is not operating. Boiler Nos. 2, 3 and 4 are all operating at 70-percent load to achieve the 450,000 lb/hr steam total. Boiler No. 4 is burning the maximum amount of oil (1,500 gal/hr of 0.7-percent sulfur oil), while Boiler No. 3 is burning 749 gal/hr oil to make up the remainder of the total 2,250 gal/hr. Stack velocities are adjusted accordingly.

CASE E (24-HR)

- Same as Case D, except that Boiler No. 3is burning the maximum amount of oil (900 gal/hr of 1.6-percent sulfur oil), while Boiler No. 4 is burning 1,350 gal/hr oil to make up the remainder of the total 2,250 gal/hr.

3. The model output files for the load analysis were attached to the September 8 submittal. From the load analysis, the scenarios resulting in the worst-case impacts for the future Clewiston mill alone were identified for each pollutant and averaging time. These scenarios were then used in the AAQS and PSD increment modeling analysis. The scenarios for each pollutant are shown in Tables 6-21 and 6-23.

4. The PSD baseline SO_2 inventory shown in Table 6-8 for the Clewiston mill is correct based on all available information. As discussed in Golder's May 3, 2000 letter to the Department, in regards to FDEP No. 1 and EPA No. 1 comments, Boiler Nos. 1, 2 and 3 have not changed in relation to steam production rates, maximum heat input rates, oil burning capability, or fuel sulfur content since the PSD 1975 baseline date. Each boiler had no restriction on fuel oil burning in 1975, and therefore Boiler Nos. 1, 2 and 3 could burn up to 1,500, 1,500 and 900 gal/hr, respectively, of 2.5-percent sulfur fuel oil. These are the physical limitations of the fuel oil burners, and have not changed since the baseline date. On this basis, it is reasonable to assume that, during the baseline period, the boilers operated burning the maximum amount of fuel oil for a 3-hour period and up to 88,800 gallons per 24-hour period (which is the current 24-hour fuel burning restriction for the Clewiston mill). In reality, greater quantities of oil may have been burned in a 24-hour period during the baseline, because of the low cost of fuel oil at the time. For this reason, the baseline SO_2 emissions for Boiler Nos. 1, 2 and 3 were set equal to the future maximum SO_2 emissions for these boilers, as presented in Table 6-3 of the original Boiler No. 4 modification application submitted in June 1999. Note that since the June 1999 application, changes have been made to the maximum future SO_2 emissions for these boilers.

For SO_2 emissions from the East and West Pellet mills for the baseline period, air construction permit applications dated October 1974 formed the basis. The applications showed 39,000 lbs/day of 2.5-percent sulfur oil as feed to the burners for each plant:

$$39{,}000 \text{ lbs/day} \times 2.5\% \text{ S} \times 2 / 24 = 81.3 \text{ lb/hr} = 10.3 \text{ g/s}$$

The stack heights of Boiler Nos. 1, 2 and 3 as of the 1975 baseline date are well documented in the historic permitting files and permit applications (for example, the 1984 application for Boiler No. 4). The heights were 75 feet for Boiler Nos. 1 and 2, and 90 feet for Boiler No. 3.

Please call or e-mail me if you have any additional questions concerning this information.

Sincerely,
Golder Associates Inc.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P.E. # 19011

DB/jkw

Attachments

cc: Don Griffin
Bill Wehrum
Lisa Gefen
Stan Krivo, EPA Region IV
National Park Service
D. Knowles, SD

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1. Article Addressed to:

Mr. Murray T. Brinson
Vice President
United States Sugar Corp.
111 Ponce De Leon Ave
Clewiston, FL 33440

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Mr. Murray T Brinson, Vice President
Street, Apt. No.; or PO Box No. 111 Ponce De
United States Sugar Corp Leon Ave
City, State, ZIP+4 Clewiston, FL 33440

PS Form 3800, February 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 11, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Additional Information Request No. 3
DEP File No. 0510003-010-AC (PSD-FL-272A)
Boiler No. 4 Modification – Part 2
Revised ISC Prime Modeling Scenario

Dear Mr. Brinson:

On September 11, 2000 the Department received additional information for the above referenced project. The Department reviewed this information and has some additional questions regarding the revised modeling scenario. The application remains incomplete. In order to continue processing your application, the Department will need the additional information attached to this letter. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. As was stated early in the permitting process for this project, since the modeling was performed using ISC Prime, EPA must approve the results. The department is waiting for EPA's comments, and will forward them to you as soon as we receive them.
2. The four tables summarizing the modeling inputs for determining SO_2 impacts from the project are confusing. Please clarify these tables by providing a thorough description of each SO_2 operating scenario modeled. Provide the basis for the operating conditions, steam production rates (percent capacity) and oil consumption.
3. Please clarify which operating scenario provided the worst-case impacts for each pollutant.
4. Please provide detailed calculations justifying the emission rates used for the PSD baseline modeling inputs. Were the stack heights for boilers 1, 2 and 3 only 23.1, 23.1 and 27.4 m, respectively?

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature.

A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If you have any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to the project meteorologist, Cleve Holladay, at 850/921-8986.

Sincerely,

Cleve Holladay, Project Meteorologist
New Source Review Section

ch

cc: Mr. David Buff, P.E., Golder Associates
Mr. David Knowles, SD
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Golder Associates Inc.

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

May 3, 2000

0037504

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MAY 04 2000
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention : Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
REVISED ISC-PRIME MODELING SCENARIO
REQUEST FOR ADDITIONAL INFORMATION NO. 1

Dear Mr. Koerner:

United States Sugar Corporation (U.S. Sugar) has received the Department's letter dated February 4, 1999 (should read February 4, 2000), requesting additional information in regards to the revised ISC-PRIME modeling scenario. The results of the revised modeling scenario were submitted to the Department in a letter from Golder Associates Inc. dated December 17, 1999. The purpose of this letter is to address the questions in the Department's letter, as well as comments from the U.S. EPA in their February 4, 2000, letter. The comments are addressed below, in the same order as they appear in the comment letters. Note that U.S. Sugar has performed dispersion modeling for all pollutants for an "off-season" operating scenario, as described below. Note that a complete set of Section 6.0 tables (from the PSD report) are attached, revised to be consistent with the current modeling.

FDEP No. 1 and EPA No. 1

Boilers No. 1, 2 and 3 are operating today and have not changed short-term (24 hours or less) operation or emissions since the baseline year (1974). The only changes to these boilers are increases in the stack heights for each of the three boilers, and operation beyond the normal sugar cane processing season.

For SO_2, emission rates have not changed since the baseline period. The boilers burned fuel oil up to their maximum capacity at times during the baseline period, with the same fuel oil sulfur content as now allowed. Therefore, these sources were modeled with the same emission rates in the baseline and in the future operating scenario. To do otherwise would inappropriately show increment consumption from these sources.

For PM emissions, the baseline emission rates are different than (i.e., lower than) the future emission rates, based on previous modeling analysis performed for the Clewiston Mill.

Boiler Nos. 1, 2 and 3 are currently not restricted on annual operating hours, and are not restricted to operating only during the crop season. Due to recent startup of the sugar refinery, these boilers may now operate during the sugar cane processing off-season. As a result, these boilers were re-modeled as operating year around in the future for all pollutants, and for 5 months only during the baseline. Thus, during the off-season, these boilers are totally increment consuming.

FDEP No. 2 and EPA No. 2
The stack locations as presented in Table 10 of the December 17, 1999 submittal are incorrect. The Section 6.0 table, which is correct, is attached, along with all Section 6.0 tables.

FDEP No. 3 and EPA No. 4
The stack exit temperatures, velocities and diameters for Boiler Nos. 1, 2 and 3 do not change as a result of raising the stack heights from 165 feet to 182 feet.

FDEP No. 4 and EPA No. 5
Refined SO_2 modeling has been performed and results are attached in the Section 6.0 tables.

FDEP No. 5
No response necessary.

EPA No. 3
No response necessary; however, the revised modeling utilizes the 8-hour CO emissions for the 8-hour modeling.

Revised Air Quality Impact Assessment
Based upon the above model related comments, Golder Associates has performed additional modeling analysis in order to bring the project impacts up to date. All model runs have been re-executed using the ISC-PRIME model. All modeling was performed with the final selected control option of raising the existing stacks on Boiler Nos. 1, 2 and 3 from the current 165 feet to a height of 182 feet. Note that a complete set of tables from Section 6.0 are being provided, including additional tables reflecting crop-season emissions and impacts.

Separate model runs were executed for crop season operation and off-season operation. The following forms the basis of the modeling analysis for the crop season operation.

Crop season operation:

- All boilers (Nos. 1, 2, 3, 4, and 7) operating at maximum capacity.
- Boiler Nos. 1, 2 and 3 are restricted to burning fuel oil with no greater than 2.5% sulfur.
- Boiler No. 4 is restricted to burning fuel oil with no greater than 0.7% sulfur (with a separate fuel oil tank).
- Boiler No. 7 is restricted to burning fuel oil with no greater than 0.05% sulfur (with a separate fuel oil tank).

- The worst case for SO_2 emissions occur with Boiler Nos. 1, 2, 3 and 4 burning the maximum amount of fuel oil, with the remainder of heat input due to bagasse burning. The worst case SO_2 emissions for Boiler No. 7 are when burning 100 percent bagasse.
- Maximum 3-hour No. 6 fuel oil consumption (total of Boiler Nos. 1, 2, 3 and 4) is limited to 16,200 gallons per 3-hour period.
- Maximum 24-hour No. 6 fuel oil consumption is limited to 88,800 gallons per 24-hour period.

The following forms the basis of the modeling analysis for the off-season operation.

Off-season operation:

1-, 3- and 8-Hour Operation:

- Total steam generation from all boilers (Nos. 1, 2, 3, 4, and 7) is limited to 1,062,800 lb/hr steam.
- Boiler Nos. 1, 2 and 3 are restricted to burning fuel oil with no greater than 1.6% sulfur during the off-season. U.S. Sugar will comply with this requirement by minimizing the amount of No. 6 fuel oil contained in the fuel oil tank for Boiler Nos. 1, 2 and 3 at the end of each crop season, and purchasing only No. 6 oil with a maximum sulfur content of 1.6% during the off-season. (Note: a separate tank provides these boilers with fuel oil)
- Boiler No. 4 continues to be restricted to burning fuel oil with no greater than 0.7% sulfur (with a separate fuel oil tank).
- Boiler No. 7 continues to be restricted to burning fuel oil with no greater than 0.05% sulfur (with a separate fuel oil tank).
- The worst case for SO_2 emissions occurs with Boiler Nos. 1, 2, and 3 operating at maximum steaming rate, burning the maximum amount of fuel oil, with the remainder of heat input due to bagasse burning. Boiler No. 4 or Boiler No. 7 could also be operated burning the maximum amount of fuel oil, up to a total steaming rate of 1,062,,800 lb/hr for all boilers.
- Total No. 6 fuel oil consumption (total of Boiler Nos. 1, 2, 3 and 4) is limited to 11,700 gallons per 3-hour period.

24-Hour Operation:

- Total steam generation from all boilers (Nos. 1, 2, 3, 4, and 7) is limited to 744,000 lb/hr steam (24-hr average). Boiler Nos. 1, 2 and 3 are limited to generating 250,000 lb/hr steam solely from No. 6 fuel oil firing (24-hr average). Boiler Nos. 4 or 7 can be used at maximum capacity, burning fuel oil or bagasse, as long as total steam generation from all boilers is limited to 744,000 lb/hr (24-hr average).
- Boiler Nos. 1, 2 and 3 are restricted to burning fuel oil with no greater than 1.6% sulfur during the off-season. U.S. Sugar will comply with this requirement by minimizing the amount of No. 6 fuel oil contained in the fuel oil tank for Boiler Nos. 1, 2 and 3 at the end of each crop season, and

purchasing only No. 6 oil with a maximum sulfur content of 1.6% during the off-season. (Note: a separate tank provides these boilers with fuel oil)

- Boiler No. 4 continues to be restricted to burning fuel oil with no greater than 0.7% sulfur (with a separate fuel oil tank).
- Boiler No. 7 continues to be restricted to burning fuel oil with no greater than 0.05% sulfur (with a separate fuel oil tank).
- The worst case for SO_2 emissions occurs with Boiler Nos. 3 burning the maximum amount of fuel oil, with the remainder of heat input to Boiler No. 3 due to bagasse burning (past dispersion modeling has shown Boiler No. 3 to be critical due to its lower plume rise compared to Boiler Nos. 1 and 2). Boiler No. 2 then supplies the remaining steam due to No. 6 fuel oil firing. Boiler No. 4 or Boiler No. 7 could also be operated burning the maximum amount of fuel oil, up to a total steaming rate of 744,000 lb/hr (24-hr average) from all boilers.
- Total No. 6 fuel oil consumption (total of Boiler Nos. 1, 2, 3 and 4) is limited to 54,546 gallons per 24 period.

Maximum PM and CO emissions occur under 100 percent bagasse firing in all boilers. Two PM_{10} modeling scenarios were performed to evaluate the off-season operation options.

A shown in the attached Section 6.0 tables, compliance with all standards and increments is predicted with the ISC-PRIME model. All model input and output files have been placed on Golder's FTP site for access by FDEP and EPA at ftp.golder.com/gville/srm/cleve/USSCLEW.

Thank you for consideration of this information. Please call or e-mail me if you have any additional questions.

Sincerely,

Golder Associates Inc.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P.E. #19011

DB/jkw

Attachments
cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
National Park Service
P:\Projects\2000\0037\0037504Y\F1\WP\#01ltr.doc

CC: File
C. Holladay, BAR

Table 2-1. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (Revised 05/05/00)

Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceuos Fuel			
Particulate Matter (PM)	0.15	1	633	600	95.0	90.0
Particulate Matter (PM10)	0.14	2	633	600	88.3	83.7
Sulfur dioxide	0.06	1	633	600	38.0	36.0
Nitrogen oxides	0.20	1	633	600	126.6	120.0
Carbon monoxide	6.5	1	633	600	4,114.5	3,900.0
VOC	0.5	1	633	600	316.5	300.0
Sulfuric Acid Mist	0.0037	3	633	600	2.3	2.2
Lead	4.45E-04	4	633	600	0.28	0.27
Mercury	3.8E-05	5	633	600	0.0241	0.0228
Beryllium	--	4	633	600	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	225	--	22.5	22.5
Particulate Matter (PM10)	0.10	6	225	--	22.5	22.5
Sulfur dioxide (b)	0.72	7	225	--	162.0	162.0
Nitrogen oxides	0.31	8	225	--	69.8	69.8
Carbon monoxide	0.033	8	225	--	7.5	7.5
VOC	0.0019	8	225	--	0.4	0.4
Sulfuric Acid Mist	0.044	3	225	--	9.9	9.9
Lead	1.01E-05	8	225	--	2.27E-03	2.27E-03
Mercury	7.53E-07	8	225	--	1.70E-04	1.70E-04
Beryllium	1.85E-07	8	225	--	4.17E-05	4.17E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			530	499	68.3	63.6
Particulate Matter (PM10)			530	499	65.1	60.7
Sulfur dioxide			530	499	180.3	178.4
Nitrogen oxides			530	499	130.9	124.5
Carbon monoxide			530	499	1,993.3	1,787.2
VOC			530	499	153.2	137.3
Sulfuric Acid Mist			530	499	11.0	10.9
Lead			530	499	0.14	0.12
Mercury			530	499	0.012	0.011
Beryllium			530	499	4.17E-05	4.17E-05
			Maximum Any Combination			
Particulate Matter (PM)					95.0	90.0
Particulate Matter (PM10)					88.3	83.7
Sulfur dioxide					180.3	178.4
Nitrogen oxides					130.9	124.5
Carbon monoxide					4,114.5	3,900.0
VOC					316.5	300.0
Sulfuric Acid Mist					11.0	10.9
Lead					0.28	0.27
Mercury					0.0241	0.0228
Beryllium					4.17E-05	4.17E-05

Table 2-2. Future Maximum Annual Emissions, Clewiston Boiler No. 4, U.S. Sugar Corp. (Revised 04/27/00)

Pollutant	Bagasse Firing			Fuel Oil Firing			Total
	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emissions (TPY)
Particulate Matter (PM)	0.15 lb/MMBtu	2,880,000	216.0	0.1 lb/MMBtu	0	0.0	216.0
PM10	0.14 lb/MMBtu	2,880,000	201.6	0.1 lb/MMBtu	0	0.0	201.6
Sulfur Dioxide	0.06 lb/MMBtu	2,805,000	84.15	0.72 lb/MMBtu (b)	75,000	27.0	111.2
Nitrogen Oxides	0.2 lb/MMBtu	2,805,000	280.5	0.31 lb/MMBtu	75,000	11.6	292.1
Carbon Monoxide	6.5 lb/MMBtu	2,880,000	9,360.0	0.033 lb/MMBtu	0	0.0	9,360
Volatile Organic Compounds	0.5 lb/MMBtu	2,880,000	720.0	0.0019 lb/MMBtu	0	0.0	720
Sulfuric Acid Mist	0.0037 lb/MMBtu	2,805,000	5.19	0.044 lb/MMBtu	75,000	1.65	6.84
Lead	4.45E-04 lb/MMBtu	2,880,000	0.6	1.01E-05 lb/MMBtu	0	0.0	0.64
Mercury	3.80E-05 lb/MMBtu	2,880,000	0.1	7.53E-07 lb/MMBtu	0	0.0	0.055
Beryllium	--	2,805,000	0.0	1.85E-07 lb/MMBtu	75,000	6.94E-06	6.94E-06

(a) Total heat input based on total steam production of 1.368E+09 lb steam/yr, 1,160 Btu/lb steam and 55% thermal efficiency.
Fuel oil considered where worst case emission factor is due to oil burning. Maximum fuel oil burning is 500,000 gal/yr, equivalent to 75,000 MMBtu/yr.

(b) Represents maximum sulfur content of 0.7 percent for fuel oil.

Table 2-1. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (Revised 05/05/00)

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 300,000 lb/hr at 600 psig, 750 F.
Maximum 6-hour average activity factor based on steam production rate of 285,000 lb/hr at 600 psig, 750 F.
Enthalpy of steam = 1,378 Btu/lb. Enthalpy of feedwater = 218 Btu/lb. Net enthalpy = 1,160 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (300,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 168 MMBtu/hr
Required heat input to boiler from bagasse = 168 MMBtu/hr / 55% eff. = 305.5 MMBtu/hr
Total heat input required = 225 + 305.5 = 530 MMBtu/hr
Max 24-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (285,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 150.6 MMBtu/hr
Required heat input to boiler from bagasse = 150.6 MMBtu/hr / 55% eff. = 273.8 MMBtu/hr
Total heat input required = 225 + 274 = 499 MMBtu/hr

(b) The SO2 emission factor reflects the maximum sulfur content (0.7%).

References

1. Limit contained in Permit No. 0510003-009-AC (PSD-FL-272).
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
4. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
5. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
6. Assumed as 100% of PM emissions.
7. Based on 0.7% S fuel oil; 142,000 Btu/gal; 7.3 lb/gal; assumes 100% conversion of sulfur to SO2.
8. Based on AP-42, Section 1.3, Fuel Oil Combustion.
   NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
   Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Multiple Fuel Combustion:
= {(Bagasse Activity Factor - Fuel Oil Activity Factor) x Bagasse Emission Factor}
+ (Fuel Oil Activity Factor x Fuel Oil Emission Factor)

Table 2-3. Summary of PM/PM10 Emissions from the Baghouses Associated With the Sugar Refinery, U.S. Sugar Corporation

Source / Vent Name	Stack Number	Control Type	Manufacturer/Model	Design Capacity	Control Efficiency (percent)	Operating Hours	PM/PM10 Emission Rate gr/dscf	lb/hr	TPY
Existing Sources									
Screening & Distribution Vacuum	S-1	Baghouse	Hoffman	990 dscfm	99.9	8,760	0.00754 [a]	0.064 [b]	0.280
100 lb Bagging Vacuum System	S-2	Baghouse	Hoffman	872 dscfm	99.9	8,760	0.00856 [a]	0.064 [b]	0.280
5 lb Bagging Vacuum System	S-3	Baghouse	Hoffman	984 dscfm	99.9	8,760	0.00759 [a]	0.064 [b]	0.280
Packaging Dust Collector	S-4	Baghouse	Hosokawa Mikropul	9,589 dscfm	99.9	8,760	0.0025	0.205	0.900
Screening and Distribution #1	S-5	Baghouse	Hosokawa Mikropul	2,668 dscfm	99.9	8,760	0.0025	0.057	0.250
Screening and Distribution #2	S-6	Baghouse	Hosokawa Mikropul	8,755 dscfm	99.9	8,760	0.0025	0.188	0.822
Conditioning Silo No. 2	S-7	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.248
Conditioning Silo No. 4	S-8	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.248
Conditioning Silo No. 6	S-9	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.248
White Sugar Dryer	S-10	Baghouse	BACT Engineering	94,488 dscfm	99.9	8,760	0.00177 [a]	1.436 [b]	6.29
V.H.P. Sugar Dryer	S-11	Baghouse	BACT Engineering	110,042 dscfm	99.9	8,760	0.00172 [a]	1.625 [b]	7.12
Granular Carbon Furnace	S-12	None	–	–	–	8,760	–	0.650	2.85
Proposed Sources									
Conditioning Silo No. 1	S-13	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.248
Conditioning Silo No. 3	S-14	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.248
Conditioning Silo No. 5	S-15	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.248
Powdered Sugar / Starch Bins	S-16	Baghouse	Hosokawa Mikropul	6,128 dscfm	99.9	8,760	0.0025	0.131	0.575
							Total =	4.82	21.13

Footnotes:

[a] Back calculated from guaranteed emission rate and design flow rate.

[b] Manufacturer's guaranteed emission rate.

Notes: dscfm = dry standard cubic foot per minute.
gr/dscf = grains per dry standard cubic foot
lb/hr = pounds per hour
TPY = tons per year

Table 2-4. Emissions From Granular Carbon Regeneration Furnace, USSC Clewiston Mill Expansion

Pollutant	Manufacturer's Design[a] (lb/hr)		Maximum Estimated Emissions lb/hr	Maximum Estimated Emissions TPY[b]
PM / PM10	0.65	[c]	0.65	2.85
NO_x	3.0		3.0	13.1
SO_2	0.49	[d]	0.49	2.15
CO	3.0		3.0	13.1
VOC	1.0		1.0	4.4

Footnotes:

[a] Estimated emissions obtained from design information provided by BSP Thermal Sytems, Inc.

[b] Based on 8,760 hours per year of operation.

[c] Based on uncontrolled emissions of 32.5 lb/hr and 98% control efficiency with wet scrubber system.

[d] Based on No. 2 fuel oil combustion only. Calculation based on manufacuter's data for the Granular Carbon Furnace is shown below.

Hourly SO_2 Emission Rate = 120 gal oil/hr * 0.03% * 6.83 lb sulfur/gal oil
* 2 lb SO_2/ 1 lb sulfur
= 0.49176 lb SO_2/hr

Annual SO_2 Emission Rate = 0.49176 lb SO_2/hr
* 8,760 hr/yr * 1 Ton/2000 lb
= 2.15 TPY SO_2

Scrubber control of SO_2 emissions was not considered.

Table 2-5. Potential Emissions of VOC from Alcohol Usage, USSC Clewiston Mill Expansion

Material	VOC Content	Maximum Sugar Production (TPY)	Annual Pounds of Material Used	Potential VOC Emissions (TPY)
Isopropyl Alcohol (a)	100%	704,000	29,216	14.61

(a) Isopropyl alcohol (IPA) usage based on 1 quart IPA per 100,000 lb of sugar.

Table 2-6. Estimated Emissions from Two Sock Dryers Due to Propane Combustion, USSC Mill Expansion

Parameter	Sock Dryer No. 1	Sock Dryer No. 2
OPERATING DATA		
Maximum Operating Hours (hr/yr)	8,760	8,760
Heat Input Rate (MMBtu/hr)	0.165	0.165
Propane (gal/hr) [a]	1.7	1.7
Propane (gal/yr)	15,295	15,295
Propane (scf/hr) [a]	64.7	64.7
Propane (scf/yr)	566,824	566,824

Pollutant	Emission Factor [b]	Emissions Sock Dryer No. 1		Emissions Sock Dryer No. 2		Total Emissions	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
EMISSIONS DATA							
SO2: Propane	0.018 lb/Mgal [c]	0.000031	0.00014	0.000031	0.00014	0.000062	0.000280
NOx: Propane	14 lb/Mgal	0.024	0.11	0.024	0.11	0.048	0.22
PM/PM10: Propane	0.4 lb/Mgal	0.00074	0.0031	0.00074	0.0031	0.00148	0.0062
CO: Propane	1.9 lb/Mgal	0.0033	0.015	0.0033	0.015	0.0066	0.030
NMVOC: Propane	0.5 lb/Mgal	0.00087	0.0038	0.00087	0.0038	0.0017	0.0076

Note: NA = not applicable.

[a] Based on 94,500 Btu/gal and 2,550 Btu/scf for propane.

[b] Emission factors based on AP-42.

[c] Formula is 0.10*S where "S" denotes the sulfur content in gr/100 ft^3 gas vapor. S equals 0.18 gr/100 ft^3.

Table 2-7. Stack Parameters for Existing and Modified Boiler No. 4

Scenario	Steam Production Rate (lb/hr)	Stack Height (ft)	Stack Diameter (ft)	Gas Flow Rate (acfm)	Gas Velocity (fps)	Gas Temperature (°F)
Existing Conditions[a]						
Boiler No. 4	250,000	150	8.2	234,000	73.85	160
Future Conditions[b]						
Boiler No. 4	285,000	150	8.2	266,800	84.20	160

Note: acfm = actual cubic feet per minute.
°F = degrees Fahrenheit.
fps = feet per second.
ft = feet.
lb/hr = pounds per hour.

[a]Represents conditions during latest compliance testing.
[b]Represents maximum 24-hour-average operating conditions.

Table 2-8. Stack and Vent Geometry and Operating Data for U.S. Sugar Refinery, U.S. Sugar Corporation, Clewiston Florida

Source / Vent Name	Stack/Vent Release Height (ft)	Stack/Vent Diameter (ft)	Exhaust Flow (acfm)	Exit Velocity* (ft/sec)	Gas Exit Temperature (°F)
Existing Sources					
Screening & Distribution Vacuum	65	0.50	1,705	0.29	68
100 lb Bagging Vacuum System	65	0.50	1,564	0.29	90
5 lb Bagging Vacuum System	65	0.50	1,585	0.29	90
Packaging Dust Collector	60	1.94	11,500	0.29	125
Screening and Distribution #1	72	0.95	3,200	0.29	125
Screening and Distribution #2	72	1.94	10,500	0.29	125
Conditioning Silo No. 2	130	1.37	3,000	0.29	110
Conditioning Silo No. 4	130	1.37	3,000	0.29	110
Conditioning Silo No. 6	130	1.37	3,000	0.29	110
White Sugar Dryer	75	7.31	113,000	0.29	115
V.H.P. Sugar Dryer	10	4.79	127,000	0.29	115
Granular Carbon Furnace	30	2.00	4,300	22.8	160
Proposed Sources					
Conditioning Silo No. 1	130	1.37	3,000	0.29	110
Conditioning Silo No. 3	130	1.37	3,000	0.29	110
Conditioning Silo No. 5	130	1.37	3,000	0.29	110
Powdered Sugar / Starch Bins	55	2.00	6,500	34.5	100

Footnotes:

* All sources but the Granular Carbon Furnance and the Powdered Sugar/Starch Bins have horizontal discharge.

Table 3-3. Baseline Emissions for Clewiston Boiler No. 4, U.S. Sugar Corp. (Revised 04/27/00)

Pollutant	Bagasse Firing				Fuel Oil Firing				TOTAL EMISSIONS (TPY)
	Emission Factor	Ref.	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Ref.	Heat Input (b) (MMBtu/yr)	Emissions (TPY)	
Particulate Matter (PM)	0.12 lb/MMBtu	1	1,661,913	99.7	0.1 lb/MMBtu	4	15,816	0.79	100.5
PM10	0.112 lb/MMBtu	2	1,661,913	93.1	0.1 lb/MMBtu	9	15,816	0.79	93.9
Sulfur Dioxide	0.008 lb/MMBtu	1	1,661,913	6.6	1.67 lb/MMBtu	5	15,816	13.21	19.9
Nitrogen Oxides	0.082 lb/MMBtu	1	1,661,913	68.1	0.31 lb/MMBtu	10	15,816	2.45	70.6
Carbon Monoxide	6.36 lb/MMBtu	1	1,661,913	5,284.9	0.033 lb/MMBtu	10	15,816	0.26	5,285.1
Volatile Organic Compounds	0.25 lb/MMBtu	3	1,661,913	207.7	0.0019 lb/MMBtu	10	15,816	0.015	207.8
Sulfuric Acid Mist	0.00049 lb/MMBtu	6	1,661,913	0.41	0.085 lb/MMBtu	6	15,816	0.67	1.08
Lead	4.45E-04 lb/MMBtu	7	1,661,913	0.37	1.01E-05 lb/MMBtu	10	15,816	7.99E-05	0.37
Mercury	8.00E-06 lb/MMBtu	8	1,661,913	6.65E-03	7.53E-07 lb/MMBtu	10	15,816	5.95E-06	6.65E-03
Beryllium	–	7	1,661,913	0.0	1.85E-07 lb/MMBtu	10	15,816	1.46E-06	1.46E-06

(a) Based on actual steam production during 1997 and 1998, and actual steam enthalpies during stack tests.
(b) Based on average fuel oil usage during last two crop seasons of 90,686 gal (1997) and 119,395 gal (1998) and 151,000 Btu/gal

Footnotes:
(1) Based on average of stack tests from last 5 years.
(2) Based on 93 percent of PM emissions for bagasse burning based on limited testing of a bagasse boiler.
(3) Test data not available; assumed equal to permit limit of 1.7 lb/ton wet bagasse.
(4) Based on permit limit.
(5) Based on stoichiometric calculation of sulfur content (1.5 percent) and density of No. 6 fuel oil (8.22 lb/gal).
(6) Based on assuming 5 percent of SO_2 emissions are equal to SO_3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
(7) Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
(8) Based on average emission factor from stack testing of 5 bagasse boilers in Florida (refer to appendices).
(9) Assumed as 100 percent of PM emissions.
(10) Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Table 3-4. Net Emissions Increase for Clewiston Boiler No. 4, U.S. Sugar Corp. (Revised 04/27/00)

Pollutant	PSD Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	100.5	216.0	115.5	25	Yes
PM_{10}	93.9	201.6	107.7	15	Yes
Sulfur Dioxide	17.7	111.2	93.5	40	Yes
Nitrogen Oxides	70.6	292.1	221.5	40	Yes
Carbon Monoxide	5,285.1	9,360.0	4,074.9	100	Yes
Volatile Organic Compound	207.8	720.0	512.2	40	Yes
Sulfuric Acid Mist	1.09	6.84	5.75	7	Yes
Lead	0.37	0.64	0.27	0.6	No
Mercury	0.007	0.055	0.048	0.1	No
Beryllium	1.46E-06	6.94E-06	5.47E-06	4.00E-04	No

Table 3-5. Predicted Net Increase in Impacts Due To the Proposed Project

Pollutant	Concentration ($\mu g/m^3$)	
	Predicted Net Increase in Impacts[a]	*De Minimis* Monitoring Concentration
Sulfur Dioxide	33	13, 24-hour
Particulate Matter (PM_{10})	14	10, 24-hour
Nitrogen Dioxide	0.8	14, annual
Carbon Monoxide	1,109	575, 8-hour
Ozone [b]	512 TPY VOC	100 TPY VOC

Note: NA = not applicable; NM = no monitoring technique; TYP = tons per year

[a] Section 6.0 for air dispersion modeling results.
[b] Preconstruction monitoring analysis requred for ozone, if increase in VOC emissions are greater than 100 TPY.

Table 6-1. Major Features of the ISCST3 Model, Version 99155

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term.
Source: EPA, 1999.

Table 6-2. Summary of Stack Parameters for Future Sources Used in Modeling of U.S. Sugar Clewiston Mill

Emission Unit	Modeling ID	Stack Height		Stack Diameter		Temperature		Flow Rate		Velocity (a)		Relative Location (b)			
												X		Y	
		(ft)	(m)	(ft)	(m)	(F)	(K)	(dscfm)	(acfm)	(ft/s)	(m/s)	(ft)	(m)	(ft)	(m)
BOILERS															
Boiler 1	USSBLR1	182	55.5	8.00	2.44	165	347.0	--	190,000	63.0	19.2	185	56.39	-5	-1.52
Boiler 2	USSBLR2	182	55.5	8.00	2.44	150	338.7	--	190,000	63.0	19.2	143	43.59	-5	-1.52
Boiler 3	USSBLR3	182	55.5	8.00	2.44	140	333.2	--	108,000	35.8	10.9	95	28.96	18	5.49
Boiler 4	USSBLR4	150	45.7	8.25	2.51	160	344.3	--	266,800	83.2	25.4	0	0.00	0	0.00
Boiler 7	USSBLR7	225	68.6	8.50	2.59	270	405.4	--	290,000	85.2	26.0	-58	-17.68	65	19.81
REFINERY SOURCES															
Screening & Distribution Vacuum	S1	65	19.8	0.50	0.15	68	293.2	990	1,705	0.29	0.01	664.79	202.63	-155.17	-47.30
100 lb Bagging Vacuum System	S2	65	19.8	0.50	0.15	90	305.4	872	1,564	0.29	0.01	700.98	213.66	-147.48	-44.95
5 lb Bagging Vacuum System	S3	65	19.8	0.50	0.15	90	305.4	984	1,585	0.29	0.01	700.98	213.66	-147.48	-44.95
Packaging Dust Collector	S4	60	18.3	1.94	0.59	125	324.8	9,589	11,500	0.29	0.01	774.34	236.02	-131.89	-40.20
Screening and Distribution #1	S5	72	21.9	0.95	0.29	125	324.8	2,668	3,200	0.29	0.01	700.98	213.66	-147.48	-44.95
Screening and Distribution #2	S6	72	21.9	1.94	0.59	125	324.8	8,755	10,500	0.29	0.01	700.98	213.66	-147.48	-44.95
Conditioning Silo No. 2	S7	130	39.6	1.37	0.42	110	316.5	2,641	3,000	0.29	0.01	637.28	194.24	-150.8	-45.96
Conditioning Silo No. 4	S8	130	39.6	1.37	0.42	110	316.5	2,641	3,000	0.29	0.01	602.07	183.51	-158.28	-48.24
Conditioning Silo No. 6	S9	130	39.6	1.37	0.42	110	316.5	2,641	3,000	0.29	0.01	566.85	172.78	-165.77	-50.53
White Sugar Dryer Baghouse	S10	75	22.9	7.31	2.23	115	319.3	94,488	113,000	0.29	0.01	695.66	212.04	-194.62	-59.32
V. H. P. Sugar Dryer Baghouse	S11	10	3.0	4.79	1.46	115	319.3	110,042	127,000	0.29	0.01	2045.01	623.32	214.88	65.50
Granular Carbon Furnace	S12	30	9.1	2.00	0.61	160	344.3	--	4,300	22.8	6.9	603.97	184.09	-398.13	-121.35
Conditioning Silo No. 1	S13	130	39.6	1.37	0.42	110	316.5	2,641	3,000	0.29	0.01	622.85	189.84	-92.52	-28.20
Conditioning Silo No. 3	S14	130	39.6	1.37	0.42	110	316.5	2,641	3,000	0.29	0.01	588.61	179.41	-99.8	-30.42
Conditioning Silo No. 5	S15	130	39.6	1.37	0.42	110	316.5	2,641	3,000	0.29	0.01	549.49	167.48	-108.12	-32.95
Powdered Sugar Starch Bins	S16	55	16.8	2.00	0.61	100	310.9	6,128	--	34.5	10.50	767.14	233.82	-266.32	-81.17

(a) All refinery sources except granular carbon furnace have horizontal discharge: velocity set at 0.01 m/s for modeling purposes.

(b) Relative to Boiler No. 4 stack location.

Table 6-3. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Crop Season Operation:
(12/17/99)

Boilers 1-3 @ 2.5% sulfur fuel oil; 182 ft stack height
Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
3	342.0 [c]	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	633.0	225.1	1,500	213.0	420.0	58,333	153.3	42.0 [d]	195.3	24.61
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	798.0	1,980.2	275,028	1,752.3	232.0	1,984.3	250.0
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
2	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
3	342.0	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	600.0	225.1	0	0.0	600.0	83,333	0.0	60.0 [d]	60.0	7.56
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,517.0	239.5	1,756.5	221.3

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions, i.e., Boiler Nos. 1, 2 and 3 burning 2.5% sulfur oil, and Boiler No.4 burning 0.7% sulfur oil. Boiler Nos. 1, 2 and 3 have 182 ft stacks, and Boiler No. 4 has a 150 ft stack.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 2.5% sulfur
18,300 Btu/lb; 150,000 Btu/gal
2 8.2 lb/gal

0.7% sulfur
19,450 Btu/lb; 142,000 Btu/gal
7.3 lb/gal

Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

Table 6-4a. U.S. Sugar Clewiston Boiler Maximum PM_{10} and CO Emissions - Future Crop Season Operation

Source	Maximum Heat Input (MMBtu/hr)	Emission Factor		Emissions (lb/hr)	Emissions (g/s)
		MAXIMUM 24-HOUR CASE - PM10 EMISSIONS			
Boilers		PM Emission Factor	PM10 Emission Factor		
Boiler 1	495.6	0.25 lb/MMBtu	93% of PM	115.2	14.52
Boiler 2	495.6	0.25 lb/MMBtu	93% of PM	115.2	14.52
Boiler 3	342.0	0.30 lb/MMBtu	93% of PM	95.4	12.02
Boiler 4	600.0	0.15 lb/MMBtu	93% of PM	83.7	10.55
Boiler 7	738.0	0.03 lb/MMBtu	100% of PM	22.1	2.79
		MAXIMUM 1-HOUR CASE - CO EMISSIONS			
Boilers					
Boiler 1	495.6	13.0 lb/MMBtu		6,442.80	811.79
Boiler 2	495.6	13.0 lb/MMBtu		6,442.80	811.79
Boiler 3	342.0	10.0 lb/MMBtu		3,420.00	430.92
Boiler 4	633.0	6.5 lb/MMBtu		4,114.50	518.43
Boiler 7	812.0	0.7 lb/MMBtu		568.40	71.62
		MAXIMUM 8-HOUR CASE - CO EMISSIONS			
Boilers					
Boiler 1	495.6	9.2 lb/MMBtu		4,559.52	574.50
Boiler 2	495.6	12.5 lb/MMBtu		6,195.00	780.57
Boiler 3	342.0	9.1 lb/MMBtu		3,112.20	392.14
Boiler 4	633.0	6.5 lb/MMBtu		4,114.50	518.43
Boiler 7	812.0	0.7 lb/MMBtu		568.40	71.62

Table 6-4b. U.S. Sugar Clewiston Mill Maximum SO_2 Emissions - Future Off-Season Operation (04/25/00)

Boilers 1-3 @ 1.6% sulfur fuel oil; 182 ft stack height
Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Boiler Design Rates: Steam Rate (lb/hr)	Steam Enthalpy (Btu/lb)	Heat Input (MMBtu/hr)	Steam Rate: Total (lb/hr)	Steam Rate: Bagasse (lb/hr)	Steam Rate: Fuel Oil (lb/hr)	Heat Input: from Bagasse [a] (MMBtu/hr)	Heat Input: From Fuel Oil [b] (MMBtu/hr)	Fuel Oil Usage (gal/hr)	Bagasse Usage (lb/hr,dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Modeled SO_2 Emissions: Bagasse [b] (lb/hr)	Modeled SO_2 Emissions: Total (lb/hr)	Modeled SO_2 Emissions: Total (g/s)
							MAXIMUM 3-HOUR CASE							
1	255,100 [d]	1,068.6	495.6	255,100	86,650	168,450	168.4	225.0	1,500	23,382	393.6	11.7	405.3	51.07
2	255,100 [d]	1,068.6	495.6	255,100	86,650	168,450	168.4	225.0	1,500	23,382	393.6	11.7	405.3	51.07
3	167,600 [d]	1,122.4	342.0	167,600	71,395	96,205	145.7	135.0	900	20,236	236.1	10.1	246.2	31.03
4	300,000	1,160.0	632.7	0	0	0	0	0	0	0	0.0	0.0 [e]	0.0	0.00
7	385,000	1,160.0	812.0	385,000	385,000	0	812.0	0	0	112,778	0.0	138.0 [e]	138.0	17.39
Totals	1,362,800			1,062,800	629,695	433,105	1,294.4	585.0	3,900 (11,700 gallons per 3-hour period)	179,778	1,023.3	171.5	1,194.9	150.6
							MAXIMUM 24-HOUR CASE							
1	255,100 [d]	1,068.6	495.6	0	0	0	0.0	0.0	0	0	0.0	0.0	0.0	0.00
2	255,100 [d]	1,068.6	495.6	226,400	72,605	153,795	141.1	205.4	1,370	19,592	359.4	9.8	369.2	46.51
3	167,600 [d]	1,122.4	342.0	167,600	71,395	96,205	145.7	135.0	900	20,236	236.1	10.1	246.2	31.03
4	285,000	1,160.0	601.1	0	0	0	0	0	0	0	0.0	0.0 [e]	0.0	0.00
7	350,000	1,160.0	738.2	350,000	350,000	0	738.2	0	0	102,525	0.0	125.5 [e]	125.5	15.81
Totals	1,312,800			744,000	494,000	250,000	1,024.9	340.4	2,269 (54,456 gallons per 24-hour period)	142,353	595.5	145.4	740.9	93.4

[a] Based on 55% thermal efficicency.

[b] Based on 80% thermal efficiency.

[c] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[d] Maximum 24-hour average.

[e] Based on new permit limit for Boiler No. 4 of 0.06 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 1.6% sulfur
18,300 Btu/lb; 150,000 Btu/gal
8.2 lb/gal
Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

Table 6-4c. U.S. Sugar Clewiston Mill Maximum PM_{10} Emissions - Future Off-Season Operation (04/14/00)

Boilers 1-3 @ 1.6% sulfur fuel oil; 182 ft stack height

Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Boiler Design Rates			Steam Rate			Heat Input		Modeled PM_{10} Emissions			
	Steam Rate[c] (lb/hr)	Steam Enthalpy (Btu/lb)	Heat Input (MMBtu/hr)	Total (lb/hr)	Bagasse (lb/hr)	Fuel Oil (lb/hr)	From Bagasse[a] (MMBtu/hr)	From Fuel Oil[b] (MMBtu/hr)	PM (lb/MMBtu)	PM_{10} Factor	PM_{10} (lb/hr)	PM_{10} (g/s)
							CASE A (24-hr)					
1	255,100	1,068.6	495.6	0	0	0	0.0	0.0	0.25	93%	0.0	0.00
2	255,100	1,068.6	495.6	226,400	226,400	0	439.9	0.0	0.25	93%	102.3	12.89
3	167,600	1,122.4	342.0	167,600	167,600	0	342.0	0.0	0.30	93%	95.4	12.02
4	285,000	1,160.0	601.1	0	0	0	0.0	0.0	0.15	93%	0.0	0.00
7	350,000	1,160.0	738.2	350,000	350,000	0	738.2	0.0	0.03	100%	22.1	2.79
Totals	1,312,800			744,000	744,000	0	1,520.1	0.0			219.8	27.7
							CASE B (24-hr)					
1	255,100	1,068.6	495.6	0	0	0	0.0	0.0	0.25	93%	0.0	0.00
2	255,100	1,068.6	495.6	0	0	0	0.0	0.0	0.25	93%	0.0	0.00
3	167,600	1,122.4	342.0	109,000	109,000	0	222.4	0.0	0.30	93%	62.1	7.82
4	285,000	1,160.0	601.1	285,000	285,000	0	601.1	0.0	0.15	93%	83.9	10.57
7	350,000	1,160.0	738.2	350,000	350,000	0	738.2	0.0	0.03	100%	22.1	2.79
Totals	1,312,800			744,000	744,000	0	1,561.7	0.0			168.1	21.2

[a] Based on 55% thermal efficicency.

[b] Based on 80% thermal efficiency.

[c] Maximum 24-hour average.

Table 6-4d. U.S. Sugar Clewiston Mill Maximum CO Emissions - Future Off-Season Operation (04/25/00)
Boilers 1-3 @ 1.6% sulfur fuel oil; 182 ft stack height
Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Boiler Design Rates			Steam Rate			Heat Input From		CO Emission	Total CO	
	Steam Rate (lb/hr)	Steam Enthalpy (Btu/lb)	Heat Input (MMBtu/hr)	Total (lb/hr)	Bagasse (lb/hr)	Fuel Oil (lb/hr)	Bagasse [a] (MMBtu/hr)	Fuel Oil [b] (MMBtu/hr)	Rate [c] (lb/MMBtu)	(lb/hr)	(g/s)
				MAXIMUM 1-HOUR CASE							
1	255,100 [d]	1,068.6	495.6	255,100	255,100	0	495.6	0	13.0	6,443.3	811.85
2	255,100 [d]	1,068.6	495.6	255,100	255,100	0	495.6	0	13.0	6,443.3	811.85
3	167,600 [d]	1,122.4	342.0	167,600	167,600	0	342.0	0	10.0	3,420.3	430.95
4	300,000	1,160.0	632.7	300,000	300,000	0	632.7	0	6.5	4,112.7	518.20
7	385,000	1,160.0	812.0	85,000	85,000	0	179.3	0	0.7	125.5	15.81
Totals	1,362,800			1,062,800	1,062,800	0	2,145.3	0		20,545.0	2,588.7
				MAXIMUM 8-HOUR CASE							
1	255,100 [d]	1,068.6	495.6	255,100	255,100	0	495.6	0	9.2	4,559.9	574.54
2	255,100 [d]	1,068.6	495.6	255,100	255,100	0	495.6	0	12.5	6,195.5	780.63
3	167,600 [d]	1,122.6	342.1	167,600	167,600	0	342.1	0	9.1	3,113.0	392.24
4	300,000	1,160.0	632.7	300,000	300,000	0	632.7	0	6.5	4,112.7	518.20
7	385,000	1,160.0	812.0	85,000	85,000	0	179.3	0	0.7	125.5	15.81
Totals	1,362,800			1,062,800	1,062,800	0	2,145.4	0		18,106.5	2,281.4

[a] Based on 55% thermal efficicency.

[b] Based on 80% thermal efficiency.

[c] Based on actual test data from Boiler Nos. 1, 2 and 3 and permit limits for Boiler Nos. 4 and 7.

[d] Maximum 24-hour average.

Table 6-5. Summary of PM/PM_{10} Emissions from the Baghouses Associated With the Sugar Refinery, U.S. Sugar Corporation

Source / Vent Name	New Stack Number	Design Capacity	Operating Hours	PM/PM10 Emissions (gr/dscf)	(lb/hr)	(g/s)	(TPY)
Existing Sources							
Screening & Distribution Vacuum	S-1	990 dscfm	8,760	0.00754 ^a	0.064 ^b	0.00806	0.280
100 lb Bagging Vacuum System	S-2	872 dscfm	8,760	0.00856 ^a	0.064 ^b	0.00806	0.280
5 lb Bagging Vacuum System	S-3	984 dscfm	8,760	0.00759 ^a	0.064 ^b	0.00806	0.280
Packaging Dust Collector	S-4	9,589 dscfm	8,760	0.0025	0.205	0.0259	0.900
Screening and Distribution #1	S-5	2,668 dscfm	8,760	0.0025	0.057	0.00720	0.250
Screening and Distribution #2	S-6	8,755 dscfm	8,760	0.0025	0.188	0.0236	0.822
Conditioning Silo No. 2	S-7	2,641 dscfm	8,760	0.0025	0.057	0.00713	0.248
Conditioning Silo No. 4	S-8	2,641 dscfm	8,760	0.0025	0.057	0.00713	0.248
Conditioning Silo No. 6	S-9	2,641 dscfm	8,760	0.0025	0.057	0.00713	0.248
White Sugar Dryer	S-10	94,488 dscfm	8,760	0.00177 ^a	1.436 ^b	0.181	6.29
V.H.P. Sugar Dryer	S-11	110,042 dscfm	8,760	0.00172 ^a	1.625 ^b	0.205	7.12
Granular Carbon Furnace	S-12	--	8,760	--	0.650	0.0819	2.85
Proposed Sources							
Conditionsing Silo No. 1	S-13	2,641 dscfm	8,760	0.0025	0.057	0.00713	0.248
Conditionsing Silo No. 3	S-14	2,641 dscfm	8,760	0.0025	0.057	0.00713	0.248
Conditionsing Silo No. 5	S-15	2,641 dscfm	8,760	0.0025	0.057	0.00713	0.248
Powdered Sugar Bins	S-16	6,128 dscfm	8,760	0.0025	0.131	0.01655	0.575
				Total =	4.82	0.61	21.13

Footnotes:

^a Back calculated from guaranteed emission rate and design flow rate.

^b Manufacturer's guaranteed emission rate.

Note: dscfm = dry standard cubic foot per minute.
gr/dscf = grains per dry standard cubic foot
lb/hr = pounds per hour
TPY = tons per year

Table 6-6 . Summary of Competing SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses (Revised 9/9/99)

0037504Y/F1/WP/table6-6
5/3/00

APIS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to USS Clewiston Mill X (km)	Relative to USS Clewiston Mill Y (km)	Relative to USS Clewiston Mill Distance (km)	Relative to USS Clewiston Mill Direction[a] (deg)	Maximum SO_2 Emissions (TPY)	Q, Emission Threshold (Dist -53) x 20
52FTM260001	Everglades Sugar	Hendry	509.6	2954.2	3.5	-2.7	4.4	128	607	SIA
50PMB500086	Glades Correctional Institute	Palm Beach	523.4	2955.2	17.3	-1.7	17.4	96	98	SIA
52FTM260015	Southern Gardens Citrus	Hendry	487.6	2957.6	-18.5	0.7	18.5	272	409	SIA
50PMB500332	Okeelanta	Palm Beach	525.0	2937.4	18.9	-19.5	27.2	136	939	SIA
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	28.8	-3.6	29.0	97	2,555	SIA
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	32.7	11.2	34.6	71	2,698	SIA
52FTM500016	Osceola Farms	Palm Beach	544.2	2968.0	38.1	11.1	39.7	74	2,023	SIA
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	46.8	-11.7	48.2	104	954	SIA
50WPB430001	FPL -Martin	Martin	543.1	2992.9	37.0	36.0	51.6	46	93,788	SIA
50WPB430102	Bechtel Indiantown	Martin	545.6	2991.5	39.5	34.6	52.5	49	2,629	SIA
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	53.1	21.4	57.3	68	504	85.0
50WPB430007	Dickerson	Martin	569.5	2995.9	63.4	39.0	74.4	58	58	428.7
50WPB500234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	79.7	3.3	79.8	88	1,533	535.4
52FTM360119	Lee County Resource Recovery	Lee	424.0	2946.0	-82.1	-10.9	82.8	262	490	596.4
52FTM36	FPL - Fort Myers	Lee	422.1	2952.9	-84.0	-4.0	84.1	267	22,702	621.9
50WPB430021	Stuart Contracting	Martin	575.2	3006.8	69.1	49.9	85.2	54	100	644.7
50PMB500045	Lake Worth Utilities	Palm Beach	592.8	2943.7	86.7	-13.2	87.7	99	2,302	694.0
50PMB500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	88.1	3.7	88.2	88	73,475	703.6
50WPB062120	North Broward Resource Recovery	Broward	583.6	2907.6	77.5	-49.3	91.9	122	896	777.0
50WPB560003	Fort Pierce Utilities	St. Lucie	566.8	3036.3	60.7	79.4	99.9	37	2,708	938.9
50WPB062119	South Broward Resource Recovery	Broward	579.6	2883.3	73.5	-73.6	104.0	135	1,318	1020.3
50BRO060037	FPL -Lauderdale	Broward	580.1	2883.3	74.0	-73.6	104.4	135	47,858	1027.4
50BRO060036	FPL -Port Everglades	Broward	587.4	2885.3	81.3	-71.6	108.3	131	170,215	1106.7
50DAD130020	Tarmac	Dade	562.9	2861.7	56.8	-95.2	110.9	149	2,792	1157.1
50DAD130348	Dade Co. Resource Recovery	Dade	564.3	2857.4	58.2	-99.5	115.3	150	857	1245.4
30ORL310029	Vero Beach Power	St. Lucie	567.1	3056.5	61.0	99.6	116.8	31	18,496	1275.9
US Sugar Clewiston Mill Coordinates:			506.1	2956.9						

Proposed project's 24- and 3-hour emissions are significant to 53 and 60 km, respectively;
Emission imventory is limited to facilities within 103 km but includes major power plants at 104 and 108 km from the proposed project.

Table 6-7. Background SO_2 Facilities That Were Included in the PSD Class I Incremental Modeling Analysis

APIS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Everglades National Park X (km)	Relative to Everglades National Park Y (km)	Relative to Everglades National Park Distance (km)	Relative to Everglades National Park Direction[a] (deg)
50DAD130348	Dade Co. Resource Recovery	Dade	564.3	2857.4	14.0	8.8	16.5	58
50DAD130020	Tarmac	Dade	562.9	2861.7	12.6	13.1	18.2	44
50WPB062119	South Broward Resource Recovery	Broward	579.6	2883.3	29.3	34.7	45.4	40
50BRO060037	FPL -Fort Lauderdale	Broward	580.1	2883.3	29.8	34.7	45.7	41
50WPB062120	North Broward Resource Recovery	Broward	583.6	2907.6	33.3	59.0	67.7	29
52FTM360119	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.0	87.3 [b]	340
50PMB500332	Okeelanta	Palm Beach	525.0	2937.4	-25.3	88.8	92.3	344
52FTM36	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	88.9	94.5 [b]	340
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	2.6	96.6	96.6	2
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-15.4	104.7	105.8	352
52FTM260001	Evercane Sugar	Hendry	509.6	2954.2	-40.7	105.6	113.2	339
52FTM260003	US Sugar Clewiston	Hendry	506.1	2956.9	-44.2	108.3	117.0	338
50WPB500234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.5	111.6	117.1	18
52FTM500016	Osceola Farms	Palm Beach	544.2	2968.0	-6.1	119.4	119.6	357
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-11.5	119.5	120.1	355
50PMB500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	43.9	112.0	120.3	21
52FTM260015	Southern Gardens	Hendry	487.6	2957.6	-62.7	109.0	125.7	330
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	8.9	129.7	130.0	4
50WPB430102	Bechtel Indiantown	Martin	545.6	2991.5	-4.7	142.9	143.0	358
50WPB430001	FPL -Martin	Martin	543.1	2992.9	-7.2	144.3	144.5	357

[a] Distance from northeastern corner UTM location =550.3 km E, 2848.6 km N

[b] Distance from northwestern corner UTM location = 454.0 km E, 2864.0 km N

Table 6-8. Summary of Competing SO_2 Sources Included in the Air Modeling Analysis (revised 04/27/00)

APIS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
52FTM500016	Atlantic Sugar ^ a												
		Unit 1	ATLSUG1	27.4	1.83	346.0	17.97	10.85	10.85	CON	Yes	Yes	Yes
		Unit 2	ATLSUG2	27.4	1.83	350.0	23.36	10.85	10.85	CON	Yes	Yes	Yes
		Unit 3	ATLSUG3	27.4	1.83	350.0	21.56	10.50	10.50	CON	Yes	Yes	Yes
		Unit 4	ATLSUG4	27.4	1.83	344.0	25.16	10.76	10.76	CON	Yes	Yes	Yes
		Unit 5 PSD	ATLSUG5	27.4	1.68	339.0	19.24	11.84	11.84	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	18.9	1.92	506.0	12.70	-17.24	-17.24	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	ATLSUG2B	18.9	1.92	511.0	10.90	-22.50	-22.50	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	ATLSUG3B	21.9	1.83	522.0	17.50	-16.88	-16.88	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	ATLSUG4B	18.3	1.83	344.0	15.00	-10.76	-10.76	EXP	No	Yes	Yes
50WPB430102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD												
		Units 1&2	DCRRF12	76.2	3.66	405.4	15.86	26.41	12.32	CON	No	No	Yes
		Units 3&4	DCRRF34	76.2	3.66	405.4	15.86	26.41	12.32	CON	No	No	Yes
52FTM260001	Everglades Sugar ^ a Main Boiler		EVERGLAD	21.9	1.10	477.0	10.10	34.90	34.90	NO	Yes	No	No
50BRO060037	FPL - Lauderdale												
		CTs 1-4 PSD	LAUDU45	45.7	5.49	438.7	14.60	271.15	271.15	CON	Yes	No	Yes
		GT 1-12 (0.5% fuel oil)	LDGT1_12	13.7	2.37	733.2	114.31	552.80	552.80	NO	Yes	No	No
		GT 13-24 (0.5% fuel oil)	LDGT1324	13.4	4.75	733.2	28.43	552.80	552.80	NO	Yes	No	No
		4&5 PSD Baseline	FTLAU45B	46.0	4.27	422.0	14.63	-457.00	-457.00	EXP	No	No	Yes
50WPB430001	FPL Martin												
		Units 1&2	MART12	152.1	7.99	420.9	21.03	1743.79	1743.79		Yes	No	No
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes	Yes	Yes
		Diesl Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes	Yes	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes	Yes	Yes
50PMB500086	Glades Corr Institute		GLADCORR	9.8	0.40	389.0	11.28	2.82	2.82	NO	No	No	No
50WPB560003	Fort Pierce Utilities												
		Units 6&7	FTPIER67	45.7	2.19	408.2	12.50	77.87	77.87	NO	Yes	No	No
52FTM360002	FPL Fort Myers												
		Unit 1	FPLFMYU1	91.8	2.90	422.0	29.90	-585.50	-585.50	EXP	No	No	Yes
		Unit 2	FPLFMYU2	121.2	5.52	408.0	19.20	1334.0	-1334.0	EXP	No	No	Yes
		GT 1-12	FPLFMGTS	9.75	4.42	797.0	35.70	5152.4	5152.4	NO	Yes	No	No
		6 CTs, PSD	FPLFM6CT	38.1	5.79	377.6	21.43	3.86	3.86	CON	Yes	No	Yes
50PMB500045	Lake Worth Utilities												
		Unit 3	LAKWTHU3	38.1	2.13	408.2	7.71	103.95	103.95	NO	Yes	No	No
		Unit 5	LAKWTHU5	22.9	0.94	450.4	18.29	11.59	11.59	NO	Yes	No	No

Table 6-8. Summary of Competing SO_2 Sources Included in the Air Modeling Analysis (revised 04/27/00)

APIS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
52FTM360119	Lee County RRF PSD		LEECORRF	83.8	1.88	388.5	19.81	14.00	14.00	CON	No	No	Yes
50WPB062120	North Broward RRF PSD		NBCRRF	58.5	3.96	381.0	18.01	35.40	35.40	CON	No	No	Yes
50PMB500332	Okeelanta ^a												
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	No	Yes	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	No	Yes	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	No	Yes	Yes
		Boiler 12 PSD Baseline	OKBLR12B	22.9	2.29	330.0	8.16	-20.58	-20.58	EXP	No	Yes	Yes
		Boiler 14 PSD Baseline	OKBLR14B	22.9	2.29	333.0	8.28	-20.03	-20.03	EXP	No	Yes	Yes
		Boiler 15 PSD Baseline	OKBLR15B	22.9	2.29	332.0	10.23	-16.79	-16.79	EXP	No	Yes	Yes
		Okeelanta Power Blrs 1,2,3 ^b	OKCOGEN	68.6	3.05	438.7	17.46	27.0	27.0	CON	Yes	Yes	Yes
52FTM500019	Osceola Farms ^a												
		Unit 2	OSBLR2	27.4	1.52	339.0	18.63	17.12	17.12	CON	Yes	Yes	Yes
		Unit 3	OSBLR3	27.4	1.92	344.0	14.34	30.74	30.74	CON	Yes	Yes	Yes
		Unit 4	OSBLR4	27.4	1.83	344.0	16.53	17.12	17.12	CON	Yes	Yes	Yes
		Unit 5	OSBLR5	27.4	1.52	344.0	17.85	18.00	18.00	CON	Yes	Yes	Yes
		Unit 6	OSBLR6	27.4	1.92	339.0	18.25	33.39	33.39	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-5.07	-5.07	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-16.32	-16.32	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-7.26	-7.26	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-13.61	-13.61	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	OSBLR5B	22.0	1.52	342.0	12.12	-16.32	-16.32	EXP	No	Yes	Yes
50WPB500234	Palm Beach Co. Resource Recovery												
		1&2 PSD	PBCRRF	76.2	2.04	505.2	24.90	85.05	85.05	CON	No	No	Yes
50BR0060036	FPL Port Everglades												
		Units 1&2 at 2.5%s fuel oil	PTEVU12	104.5	4.27	415.9	26.72	1593.90	1593.90	NO	Yes	No	No
		Units 3&4 at 2.5%s fuel oil	PTEVU34	104.5	5.52	414.8	23.88	2772.00	2772.00	NO	Yes	No	No
		GT 1-12 (0.5% fuel oil)	PTEVGTS	13.4	4.75	733.2	28.43	530.70	530.70	NO	Yes	No	No
50WPB500234	Pratt & Whitney												
		Heater	PRATARCH	15.2	0.91	810.9	143.73	13.99	13.99	CON	No	No	Yes
		Boiler BO-12	PRATBO12	4.7	0.76	533.2	6.92	0.51	0.51	CON	No	No	Yes
50PMB500042	FPL Riviera												
		Units 3&4 at 2.5%s fuel oil	RIVU34	90.8	4.88	401.5	18.90	2113.65	2113.65	NO	Yes	No	No
50WPB062116	South Broward RRF PSD		SBCRRF	59.4	3.96	381.0	18.01	37.91	37.91	CON	No	No	Yes

Table 6-8. Summary of Competing SO_2 Sources Included in the Air Modeling Analysis (revised 04/27/00)

APIS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
50FTM260015	Southern Gardens Citrus - PSD												
		Peel Dryer	SGARDDRY	38.1	1.16	338.7	9.41	5.29	5.29	CON	Yes	Yes	Yes
		Boilers 1-3	SGARDBLR	16.8	1.22	477.6	14.23	6.48	6.48	CON	Yes	Yes	Yes
52FTM500026	Sugar Cane Growers ^a												
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes	Yes	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes	Yes	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes	Yes	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes	Yes	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	No	Yes	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	No	Yes	Yes
50DAD130020	Tarmac												
		Kiln 1	TARMC1	61.0	2.44	465.0	12.80	5.67	5.67		No	No	No
		Kiln 2 PSD Baseline	TARMC2B	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	No	No	Yes
		Kiln 3 PSD Baseline	TARMC3B	61.0	4.57	472.0	10.78	-2.76	-2.76	EXP	No	No	Yes
		Kiln 2 PSD	TABMC2P	61.0	2.44	422.0	9.10	24.57	24.57	CON	No	No	Yes
		Kiln 3 PSD	TARMC3P	61.0	4.57	450.0	11.04	51.43	51.43	CON	No	No	Yes
52FTM500061	US Sugar-Bryant ^a												
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	45.70	45.70	CON	Yes	Yes	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	109.50	109.50	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	No	Yes	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	No	Yes	Yes
	US Sugar - Clewiston - PSD Baseline												
		Unit 1 PSD Baseline	BRL1B	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	BLR2B	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	BLR3B	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	No	Yes	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes

[a] Facilities or sources within facilities that operate only during the November 1 through May 31 crop season

[b] Sugar mill sources that operate all year

Note: EXP = PSD expanding source.

Table 6-9. Summary of Background PM Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses

APIS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to USS Clewiston Mill X (km)	Relative to USS Clewiston Mill Y (km)	Relative to USS Clewiston Mill Distance (km)	Relative to USS Clewiston Mill Direction[a] (deg)	Maximum PM Emissions (TPY)	Q, Emission Threshold (Dist -4) x 20	Include in Modeling Analysis ?
52FTM260001	Everglades Sugar	Hendry	509.6	2954.2	3.5	-2.7	4.4	128	41	8.4	YES
50PMB500086	Glades Correctional Institute	Palm Beach	523.4	2955.2	17.3	-1.7	17.4	96	30	267.7	NO
52FTM260015	Southern Gardens Citrus	Hendry	487.6	2957.6	-18.5	0.7	18.5	272	250	290.3	NO
50PMB500332	Okeelanta	Palm Beach	525.0	2937.4	18.9	-19.5	27.2	136	283	463.1	NO
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	28.8	-3.6	29.0	97	1,032	500.5	YES
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	32.7	11.2	34.6	71	979	611.3	YES
52FTM500016	Osceola Farms	Palm Beach	544.2	2968.0	38.1	11.1	39.7	74	700	713.7	NO
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	46.8	-11.7	48.2	104	797	884.8	NO
50WPB430001	FPL -Martin	Martin	543.1	2992.9	37.0	36.0	51.6	46	7,578	952.5	YES
50WPB430102	Bechtel Indiantown	Martin	545.6	2991.5	39.5	34.6	52.5	49	270	970.2	NO
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	53.1	21.4	57.3	68	30	1065.0	NO
US Sugar Clewiston Mill Coordinates:			506.1	2956.9							

Proposed project is significant to 4 km; Emission inventory is limited to facilities within 54 km of the proposed project.

Table 6-10. Summary of Background PM Sources Included in the Air Modeling Analysis

APIS Number	Facility	Units	ISCST3 ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s)	PSD Source (EXP/CON)	Modeled in: AAQS	Class II
52FTM260001	Everglades Sugar [a]	Main Boiler	EVERGLAD	21.9	1.10	477.0	10.10	2.37	NO	Yes	No
50WPB430001	FPL Martin										
		Units 1&2	MART12	152.1	7.99	420.9	21.03	38.92	NO	Yes	No
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	-	CON	Yes	Yes
		Diesl Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	-	CON	Yes	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	13.33	CON	Yes	Yes
52FTM500026	Sugar Cane Growers [a]										
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	6.49	CON	Yes	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	12.95	CON	Yes	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	12.45	CON	Yes	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	12.45	CON	Yes	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	8.57	CON	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-18.94	EXP	No	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-5.70	EXP	No	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-10.90	EXP	No	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-9.10	EXP	No	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-2.50	EXP	No	Yes
52FTM500061	US Sugar-Bryant [a]										
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	12.59	CON	Yes	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	43.66	CON	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-82.40	EXP	No	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-12.04	EXP	No	Yes
	US Sugar - Clewiston - PSD Baseline										
		Unit 1 PSD Baseline	BRL1B	23.1	1.86	344.0	30.20	-7.48	EXP	No	Yes
		Unit 2 PSD Baseline	BLR2B	23.1	1.86	343.0	35.70	-7.04	EXP	No	Yes
		Unit 3 PSD Baseline	BLR3B	27.4	2.29	342.0	14.70	-4.57	EXP	No	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-1.69	EXP	No	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-0.82	EXP	No	Yes
		Units 5&6 PSD Baseline	BLR56B	23.1	1.86	494.0	44.30	-52.92	EXP	No	Yes

[a] Facilities or sources within facilities that operate only during the November 1 through May 31 crop season.

[b] Sugar mill sources that operate all year.

Note: EXP = PSD expanding source.
CON = PSD consuming source.
NO = Source does not affect PSD increment.

Table 6-11 . Summary of Background CO Facilities Considered for Inclusion in the AAQS Air Modeling Analyses

APIS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to USS Clewiston Mill X (km)	Relative to USS Clewiston Mill Y (km)	Relative to USS Clewiston Mill Distance (km)	Relative to USS Clewiston Mill Direction* (deg)	Maximum CO Emissions (TPY)	Q, Emission Threshold (Dist -3) x 20	Include in Modeling Analysis ?
52FTM260001	Everglades Sugar	Hendry	509.6	2954.2	3.5	-2.7	4.4	128	15	28.4	NO
50PMB500086	Glades Correctional Institute	Palm Beach	523.4	2955.2	17.3	-1.7	17.4	96	10	287.7	NO
52FTM260015	Southern Gardens Citrus	Hendry	487.6	2957.6	-18.5	0.7	18.5	272	723	310.3	YES
50PMB500332	Okeelanta	Palm Beach	525.0	2937.4	18.9	-19.5	27.2	136	3,289	483.1	YES
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	28.8	-3.6	29.0	97	33,771	520.5	YES
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	32.7	11.2	34.6	71	2,071	631.3	YES
52FTM500016	Osceola Farms	Palm Beach	544.2	2968.0	38.1	11.1	39.7	74	25,175	733.7	YES
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	46.8	-11.7	48.2	104	22,577	904.8	YES
50WPB430001	FPL -Martin	Martin	543.1	2992.9	37.0	36.0	51.6	46	1,816	972.5	YES
50WPB430102	Bechtel Indlantown	Martin	545.6	2991.5	39.5	34.6	52.5	49	1,647	990.2	YES
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	53.1	21.4	57.3	68	30	1085.0	NO
US Sugar Clewiston Mill Coordinates:			506.1	2956.9							

* Proposed project is significant to 3 km; Emission imventory is limited to facilities within 53 km of the proposed project.

Table 6-12. Summary of Background CO Sources Included in the Air Modeling Analysis

APIS Number	Facility	Units	ISCST3 ID Name	Stack Parameters: Height (m)	Diameter (m)	Temp. (K)	Velocity (m/s)	Emission Rate (g/s)
52FTM500016	Atlantic Sugar [a]							
		Unit 1	ATLSUG1	27.4	1.83	346.0	17.97	242.68
		Unit 2	ATLSUG2	27.4	1.83	350.0	23.36	242.68
		Unit 3	ATLSUG3	27.4	1.83	350.0	21.56	294.84
		Unit 4	ATLSUG4	27.4	1.83	344.0	25.16	311.85
		Unit 5 PSD	ATLSUG5	27.4	1.68	339.0	19.24	206.92
50WPB430102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	47.38
50WPB430001	FPL Martin							
		Units 1&2	MART12	152.1	7.99	420.9	21.03	38.92
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	---
		Diesl Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	---
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	13.33
50PMB500332	Okeelanta [a]							
		Okeelanta Power Blrs 1,2,3[b]	OKCOGEN	68.6	3.05	438.7	17.46	94.61
52FTM500019	Osceola Farms [a]							
		Unit 2	OSBLR2	27.4	1.52	339.0	18.63	317.52
		Unit 3	OSBLR3	27.4	1.92	344.0	14.34	128.77
		Unit 4	OSBLR4	27.4	1.83	344.0	16.53	317.52
		Unit 5	OSBLR5	27.4	1.52	344.0	17.85	374.22
		Unit 6	OSBLR6	27.4	1.92	339.0	18.25	310.40
50FTM260015	Southern Gardens Citrus - PSD							
		Peel Dryer	SGARDDRY	38.1	1.16	338.7	9.41	20.80
		Boilers 1-3	SGARDBLR	16.8	1.22	477.6	14.23	---
52FTM500026	Sugar Cane Growers [a]							
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	547.09
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	187.61
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	467.71
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	359.60
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	381.02
52FTM500061	US Sugar-Bryant [a]							
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	760.91
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	1309.77

[a] Facilities or sources within facilities that operate only during the November 1 through May 31 crop season.

[b] Sugar mill sources that operate all year.

Table 6-13. A Summary of Building Structures Considered in the Air Modeling Analysis

Structure	Height		Length		Width	
	ft	m	ft	m	ft	m
Mill Expansion Buildings						
Electrical Equipment	100.0	30.5	95.6	29.1	27.6	8.4
Support Structure	133.0	40.5	95.6	29.1	76.2	23.2
Dryer Area	100.0	30.5	95.6	29.1	41.8	12.7
Screening & Distribution Towers	150.0	45.7	132.2	40.3	68.7	20.9
Specialty Packaging Facility	40.0	12.2	82.1	25.0	201.6	61.5
Packaging Facility	60.0	18.3	65.0	19.8	280.0	85.3
Warehouse	28.0	8.5	339.7	103.6	289.7	88.3
Electrical & Conditioning Equipment	24.0	7.3	59.7	18.2	52.3	15.9
Bulk Loading	40.0	12.2	84.4	25.7	53.8	16.4
Sugar Silos	136.0	41.5	111.6	34.0	68.7	20.9
Other Mill Buildings						
Pellet Warehouse	46.0	14.0	527.0	160.6	105.0	32.0
WDA	51.0	15.5	55.0	16.8	53.0	16.2
Storage and Safety Mechanic	34.8	10.6	58.0	17.7	52.0	15.8
Boiler 4 Building	87.5	26.7	78.0	23.8	66.0	20.1
Boiler 5&6 Building	56.0	17.1	118.0	36.0	66.0	20.1
Boiler 1&2 Building	67.3	20.5	115.0	35.1	103.0	31.4
Power House	34.0	10.4	119.0	36.3	65.0	19.8
Warehouse	37.0	11.3	153.0	46.6	71.0	21.6
Machine Shop	39.0	11.9	309.0	94.2	106.0	32.3
B Mill Building	68.0	20.7	81.0	24.7	81.0	24.7
A Mill Building	69.0	21.0	243.0	74.1	67.0	20.4
Boiling House	93.7	28.6	181.0	55.2	155.0	47.2
Boiler 7 ESP	87.5	26.7	55.0	16.8	33.0	10.1
Boiler 7 Building	83.0	25.3	78.0	23.8	68.0	20.7
Sugar Warehouse #1	37.0	11.3	390.5	119.0	103.8	31.6
Sugar Warehouse #3	55.0	16.8	771.3	235.1	143.4	43.7

Table 6-14. Property Boundary Receptors Used in the Air Modeling Analysis

Receptor	Direction (degrees)	Distance (m)	Receptor	Direction (degrees)	Distance (m)
1	10	463	19	190	1,135
2	20	485	20	200	1,178
3	30	527	21	210	806
4	40	595	22	220	627
5	50	709	23	230	526
6	60	912	24	240	465
7	70	1,333	25	250	429
8	80	2,048	26	260	409
9	90	2,017	27	270	403
10	100	1,785	28	280	409
11	110	906	29	290	429
12	120	675	30	300	465
13	130	764	31	310	526
14	140	910	32	320	595
15	150	1,170	33	330	527
16	160	1,190	34	340	485
17	170	1,135	35	350	463
18	180	1,118	36	360	456

Note: Distances are relative to the Boiler No. 4 stack location.

Table 6-15. Everglades National Park Receptors Utilized in the PSD Class I Modeling Analysis

Receptor	UTM Coordinates (m) East	UTM Coordinates (m) North	Receptor	UTM Coordinates (m) East	UTM Coordinates (m) North
1	557000	2789000	27	540000	2848600
2	556600	2792000	28	535000	2848600
3	556000	2796000	29	530000	2848600
4	553000	2796500	30	525000	2848600
5	548000	2796500	31	520000	2848600
6	542700	2796500	32	514500	2848600
7	542700	2800000	33	514500	2843000
8	542700	2805000	34	514500	2838000
9	542700	2810000	35	514500	2832500
10	542000	2811000	36	510000	2832500
11	541300	2814000	37	505000	2832500
12	542700	2816000	38	500000	2832500
13	544100	2820000	39	495000	2832500
14	543500	2824600	40	494500	2837000
15	545000	2829000	41	491500	2841000
16	545700	2832200	42	488500	2845500
17	546200	2835700	43	483000	2848500
18	548600	2837500	44	480000	2852500
19	550300	2839000	45	475000	2854000
20	545000	2839000	46	473500	2857000
21	540000	2839000	47	473500	2860000
22	550500	2844000	48	469000	2860000
23	545000	2844000	49	464000	2860000
24	540000	2844000	50	459500	2863200
25	550300	2848600	51	454000	2863200
26	545000	2848600			

Note: U.S. Sugar Clewiston coordinates are 506100E, 2956900N
m = meter.

Table 6-16. Maximum Predicted Pollutant Impacts From Proposed Project
Screening Analysis - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	1.75	300	1500	87123124
	1.59	270	1500	88123124
	1.88	310	1500	89123124
	2.08	300	1500	90123124
	1.99	300	1500	91123124
High 24-Hour				
	27.9	240	900	87110124
	25.7	260	1200	88013024
	18.4	310	1500	89040424
	25.3	240	900	90042024
	24.0	290	1200	91052124
High 3-Hour				
	77	10	463	87011915
	92	360	456	88112306
	65	350	900	89022118
	60	240	900	90100812
	69	10	463	91030309
PM10				
Annual				
	0.80	120	675	87123124
	0.86	110	906	88123124
	0.81	310	1200	89123124
	0.79	300	1200	90123124
	0.86	300	1200	91123124
High 24-Hour				
	8.4	230	1200	87102324
	7.9	60	912	88041224
	8.0	310	1500	89040424
	11.5	240	900	90042024
	10.2	290	1200	91052124
NOx				
Annual				
	0.71	300	1500	87123124
	0.62	270	1500	88123124
	0.75	310	1500	89123124
	0.82	300	1500	90123124
	0.81	300	1500	91123124
CO				
High 8-Hour				
	1065	50	709	87062716
	891	350	600	88041816
	707	340	900	89060816
	795	240	900	90100816
	866	350	900	91042316
High 1-Hour				
	2097	350	1200	87071916
	2208	10	463	88090511
	2200	10	463	89062816
	1966	10	463	90071311
	1862	360	600	91080111

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

Table 6-17. Maximum Predicted Pollutant Impacts From Proposed Project for Comparison to EPA Significant Impact Levels - Refined Analyses - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (μg/m3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	EPA Significant Impact Levels (μg/m3)
SO_2					
Annual	2.1	302	1500	90123124	1
	2.0	300	1500	91123124	
High 24-Hour	28.3	240	800	87110124	5
	25.9	260	1100	88013024	
	32.6	244	1000	90042024	
High 3-Hour	92	360	456	88112306	25
PM10					
Annual	1.54	100	800	88123124	1
	0.86	302	1200	91123124	
High 24-Hour	13.8	244	1000	90042024	5
	11.1	292	1100	91052124	
NOx					
Annual	0.75	306	1500	89123124	1
	0.82	300	1500	90123124	
	0.81	300	1500	91123124	
CO					
High 8-Hour	1,065	50	709	87062716	500
High 1-Hour	2,134	350	1100	87071916	2000
	2,200	10	463	89062816	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Note: The project's significant impact distances (km) are SO2 - 12; PM10 - 4; CO - 3; NOx = Not significant

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

EPA = Environmental Protection Agency

Table 6-18. Maximum Predicted Pollutant Impacts From Proposed Project at the Everglades National Park PSD Class I Area - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (μg/m3)	UTM Receptor Location[b] (m)	(m)	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Levels ($\mu g/m^3$)
SO_2					
Annual					
	0.022	550300	2848600	87123124	0.1
	0.031	550300	2848600	88123124	
	0.031	545000	2848600	89123124	
	0.022	550300	2848600	90123124	
	0.027	545000	2848600	91123124	
High 24-Hour					
	0.49	540000	2848600	87021224	0.2
	0.50	535000	2848600	88071824	
	0.45	525000	2848600	89022824	
	0.67	545000	2844000	90082724	
	0.68	473500	2860000	91101924	
High 3-Hour					
	2.3	483000	2848500	87090706	1.0
	3.6	540000	2848600	88040603	
	3.6	525000	2848600	89022806	
	3.6	540000	2844000	90112603	
	2.9	545000	2848600	91012306	
PM10					
Annual					
	0.006	550300	2848600	87123124	0.2
	0.008	550300	2848600	88123124	
	0.008	545000	2848600	89123124	
	0.006	550300	2848600	90123124	
	0.006	550300	2848600	91123124	
High 24-Hour					
	0.18	545000	2829000	87050724	0.3
	0.22	535000	2848600	88071824	
	0.19	545000	2848600	89041924	
	0.31	545000	2844000	90082724	
	0.30	473500	2857000	91101924	
NOx					
Annual					
	0.009	550300	2848600	87123124	0.1
	0.012	550300	2848600	88123124	
	0.012	545000	2848600	89123124	
	0.009	550300	2848600	90123124	
	0.010	545000	2848600	91123124	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Universal Mercator Transverse coordinate system

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

PSD = Prevention of Significant Deterioration

NPS = National Park Service

EPA = Environmental Protection Agency

Table 6-18A. Maximum Predicted 24-Hour PM10 Pollutant Impacts From Proposed Project at the Everglades National Park PSD Class I Area - Refinement - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (μg/m3)	Receptor Location[b] X (km)	Receptor Location[b] Y (km)	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Level ($\mu g/m^3$)
High 24-Hour					
	0.168	62.92	-80.54	87112924	0.3
	0.169	60.07	-82.68	88011224	
	0.171	-84.73	-57.15	89080224	
	0.154	44.80	-91.86	90121324	
	0.165	-82.68	60.07	91040824	

[a] Concentrations are highest predicted with CALPUFF model and 5-year meteorological record from W. Palm Beach, 1987-91

[b] Receptors are relative to the Clewiston Mill and are located on a circle of 102 km radius, and spaced at 2-degrees intervals

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

PSD = Prevention of Significant Deterioration

NPS = National Park Service

EPA = Environmental Protection Agency

Table 6-19 (Crop). Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analyses
- Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S
- Crop Season Operation

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	29.9	310	1200	87123124
	31.1	270	1200	88123124
	33.9	310	1200	89123124
	35.8	310	1200	90123124
	33.2	300	1200	91123124
H2H 24-Hour				
	231	310	1200	87080724
	240	310	1200	88040324
	217	320	900	89061524
	208	320	900	90031624
	203	320	1200	91041624
H2H 3-Hour				
	552	310	900	87080715
	615	310	900	88090912
	574	310	900	89061212
	561	270	900	90092115
	728	310	900	91070615
PM_{10}				
Annual				
	5.5	310	1200	87123124
	5.7	270	1200	88123124
	6.4	310	1200	89123124
	6.8	310	1200	90123124
	6.3	300	1200	91123124
H2H 24-Hour				
	48.7	270	1200	87123124
	49.0	310	1500	88112024
	45.2	320	900	89060424
	43.9	320	1200	90020324
	44.3	290	1200	91050924
CO				
H2H 8-Hour				
	3,687	310	900	87061416
	3,957	280	1200	88032408
	3,863	310	900	89060516
	3,797	250	900	90031508
	4,191	310	900	91043016
H2H 1-Hour				
	7,822	340	900	87072410
	7,798	320	900	88040612
	7,930	320	900	89051714
	8,872	330	527	90080511
	9,124	40	600	91081212

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-19 (Off). Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analyses Off-Season Operation

table6-19off
5/3/00

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2				
Annual				
	19.8	130	3000	87123124
	17.7	130	3000	88123124
	20.4	130	3000	89123124
	22.3	130	3000	90123124
	20.6	130	3000	91123124
H2H 24-Hour				
	138	310	1200	87080724
	123	310	1200	88090924
	104	310	900	89072124
	106	130	3000	90012024
	134	130	3000	91050624
H2H 3-Hour				
	343	310	900	87080715
	388	310	900	88090912
	363	310	900	89061212
	343	270	900	90092115
	450	310	900	91070615
PM_{10} - Emission Scenario A				
Annual				
	2.9	300	900	87123124
	2.7	310	900	88123124
	3.3	310	900	89123124
	3.2	310	900	90123124
	3.3	300	900	91123124
H2H 24-Hour				
	27.78	310	1200	87080724
	25.46	310	1200	88090924
	28.62	310	900	89072124
	24.96	300	1200	90050424
	27.63	290	1200	91050924
PM_{10} - Emission Scenario B				
Annual				
	2.2	300	1200	87123124
	2.0	270	1200	88123124
	2.5	310	900	89123124
	2.5	300	1200	90123124
	2.5	300	1200	91123124
H2H 24-Hour				
	18.0	310	1200	87080724
	16.5	310	1500	88090924
	17.8	310	900	89072124
	19.0	240	1200	90100824
	19.6	260	1200	91102424
CO				
H2H 8-Hour				
	3,330	310	900	87061416
	2,954	270	900	88080516
	3,490	320	900	89060516
	2,847	240	1200	90100816
	3,717	310	900	91043016
H2H 1-Hour				
	7,809	340	900	87072410
	7,783	320	900	88040612
	7,908	320	900	89051714
	8,850	330	527	90080511
	9,085	40	600	91061812

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20 (Crop). Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis
- Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S
- Crop Season Operation

Averaging Time	Concentration ($\mu g/m^3$)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m3$)
	Total	Modeled	Background	Direction (degree)	Distance (m)		
SO_2							
Annual	39.7	34.7	5	316	1100	89123124	60
	40.9	35.9	5	310	1100	90123124	
	38.2	33.2	5	300	1200	91123124	
H2H 24-Hour	258	245	13	316	1100	87032424	260
	253	240	13	310	1200	88040324	
H2H 3-Hour	775	728	47	310	900	91070615	1300
PM_{10}							
Annual	29.6	6.6	23	316	1100	89123124	50
	29.8	6.8	23	310	1100	90123124	
H2H 24-Hour	90	51	39	272	1100	87123124	150
	88	49	39	310	1500	88112024	
CO							
H2H 8-Hour	7,412	3,982	3,430	280	1100	88032408	10,000
	7,736	4,306	3,430	310	800	91043016	
H2H 1-Hour	14,839	9,124	5,715	40	600	91081212	40,000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20 (Off). Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis Off-season Operation

Averaging Time	Concentration (ug/m^3)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m3$)
	Total	Modeled	Background	Direction (degree)	Distance (m)		
SO_2							
Annual	29.7	24.7	5	128	3800	87123124	60
	31.2	26.2	5	134	3900	88123124	
	31.5	26.5	5	128	3800	89123124	
	34.8	29.8	5	134	3900	90123124	
	31.9	26.9	5	130	3700	91123124	
H2H 24-Hour	151	138	13	310	1200	87080724	260
	190	177	13	134	4000	91102524	
H2H 3-Hour	467	420	47	130	900	91050624	1300
PM_{10} - Emission Scenario A							
Annual	26.4	3.4	23	314	900	89123124	50
	26.2	3.2	23	310	900	90123124	
	26.3	3.3	23	300	900	91123124	
H2H 24-Hour	67	28	39	310	1200	87080724	150
	69	30	39	314	1000	89060424	
	67	28	39	290	1200	91050924	
PM_{10} - Emission Scenario B							
Annual	25.5	2.5	23	312	1000	89123124	50
	25.5	2.5	23	300	1100	90123124	
	25.5	2.5	23	300	1100	91123124	
H2H 24-Hour	57	18	39	302	1100	87061924	150
	60	21	39	244	1000	90100924	
	59	20	39	260	1200	91102424	
CO							
H2H 8-Hour	7761	4331	3430	318	900	89060416	10000
	7681	4251	3430	310	800	91043016	
H2H 1-Hour	14800	9085	5715	40	600	91061812	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-21 (Crop). Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis
- Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S
- Crop Season Operation

Averaging Time	Concentration[a] (μg/m3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	0.1	250	11000	87123124
	0.0	0	0	88123124
	0.0	0	0	89123124
	0.1	210	11000	90123124
	0.0	0	0	91123124
H2H 24-Hour				
	7	30	11000	87030524
	9	350	11000	88060224
	12	80	11000	89040224
	11	100	11000	90042124
	8	50	11000	91040824
H2H 3-Hour				
	29	60	11000	87041324
	46	60	11000	88040521
	48	70	11000	89041303
	33	120	11000	90042203
	36	80	11000	91041121
PM_{10}				
Annual				
	<0	0	0	87123124
	<0	0	0	88123124
	<0	0	0	89123124
	<0	0	0	90123124
	<0	0	0	91123124
H2H 24-Hour				
	4.9	320	900	87100624
	6.4	330	900	88062824
	5.9	350	900	89073024
	5.4	310	900	90082924
	6.0	310	900	91083124

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-21 (Off). Maximum Predicted Pollutant PSD Class II Increments, Screening Analysis
Off-season Operation

Averaging Time	Concentration[a] (μg/m3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2				
Annual				
	7.1	300	1200	87123124
	6.0	310	1200	88123124
	7.0	310	900	89123124
	6.9	300	1200	90123124
	7.0	300	1200	91123124
H2H 24-Hour				
	70	300	1200	87061924
	59	310	1200	88100224
	81	320	900	89060424
	65	320	900	90052024
	78	290	1200	91050924
H2H 3-Hour				
	318	310	900	87080715
	343	310	900	88090912
	319	320	900	89061315
	329	270	900	90092115
	414	310	900	91070615
PM_{10} - Emission Scenario A				
Annual				
	2.4	300	900	87123124
	2.1	310	900	88123124
	2.6	310	900	89123124
	2.4	310	900	90123124
	2.5	300	900	91123124
H2H 24-Hour				
	24.2	300	1200	87061924
	20.9	270	900	88073024
	27.7	320	900	89060424
	22.3	300	1200	90050324
	27.0	290	1200	91050924
PM_{10} - Emission Scenario B				
Annual				
	1.8	300	1200	87123124
	1.6	270	1200	88123124
	1.9	310	1200	89123124
	1.9	300	1200	90123124
	1.9	300	1200	91123124
H2H 24-Hour				
	16.7	300	1200	87061924
	14.3	250	1200	88091224
	16.4	320	900	89060424
	15.6	240	900	90100924
	19.6	260	1200	91102424

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-22 (Crop). Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S - Crop Season Operation

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment ($\mu g/m^3$)
		Direction (degree)	Distance (m)		
SO_2					
Annual	0.1	250	11000	87123124	20
H2H 24-Hour	12.2	78	11000	89042324	91
H2H 3-Hour	47.7	70	11000	89041303	512
PM_{10}					
Annual	<0	0	0	0	17
H2H 24-Hour	7.6	332	1200	88081424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

Table 6-22 (Off). Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis
Off-season Operation

Averaging Time	Concentration (μg/m3)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment (μg/m3)
		Direction (degree)	Distance (m)		
SO_2					
Annual	7.1	300	1200	87123124	20
	7.1	312	1000	89123124	
	7.2	298	1000	91123124	
H2H 24-Hour	89.0	318	1000	89060424	91
H2H 3-Hour	414.4	310	900	91070615	512
PM_{10} - Emission Scenario A					
Annual	2.60	314	900	89123124	17
	2.51	298	900	91123124	
H2H 24-Hour	29.9	314	1000	89060424	30
	27.0	290	1200	91050924	
PM_{10} - Emission Scenario B					
Annual	1.92	312	1000	89123124	17
	1.92	302	1200	90123124	
	1.92	300	1100	91123124	
H2H 24-Hour	19.6	260	1200	91102424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

Table 6-23 (Crop). Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area
- Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S
- Crop Season Operation

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (ug/m^3)
Annual					
	0.16	550300	2848600	87123124	2
	0.14	535000	2848600	88123124	
	0.10	540000	2848600	89123124	
	0.20	545000	2848600	90123124	
	0.09	540000	2848600	91123124	
H2H 24-Hour					
	2.3	550300	2848600	87052924	5
	3.0	545000	2848600	88060224	
	2.8	545000	2848600	89040124	
	3.2	530000	2848600	90041224	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.5	530000	2848600	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
H2H = Highest, 2nd-Highest

Table 6-23 (Off). Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area Off-season Operation

Averaging Time	Concentration[a] (μg/m3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (μg/m3)
Annual					
	0.28	550300	2848600	87123124	2
	0.30	535000	2848600	88123124	
	0.26	550300	2848600	89123124	
	0.33	545000	2848600	90123124	
	0.23	550300	2848600	91123124	
H2H 24-Hour					
	2.4	542700	2816000	87030424	5
	3.7	540000	2848600	88042224	
	2.9	545000	2848600	89040124	
	3.3	530000	2848600	90041224	
	2.5	550300	2848600	91101924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.9	540000	2848600	91082609	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
H2H = Highest, 2nd-Highest

Table A. Baseline Emissions Used in the Significant Impact Analysis for Clewiston Boiler No. 4

Pollutant	Emission Factor (a)	Heat Input (b) (MMBtu/hr)	Emissions (lb/hr)	Emissions (g/s)
Particulate Matter (PM)	0.12 lb/MMBtu	546	65.5	8.26
PM_{10}	0.112 lb/MMBtu	546	61.2	7.71
Sulfur Dioxide	0.008 lb/MMBtu	600	4.8	0.60
Nitrogen Oxides	0.082 lb/MMBtu	(c)	16.1	2.03
Carbon Monoxide	6.36 lb/MMBtu	600	3816.0	480.82

(a) Based on source test data from Boiler No. 4.
(b) Based on maximum steam rates actually reached in operation for Boiler No. 4.
(c) Based on baseline NOx emissions of 70.6 TPY, assuming 8,760 hr/yr operation.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

SEP 20 1999

RECEIVED
SEP 24 1999
BUREAU OF AIR REGULATION

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: PSD Permit Application for U.S. Sugar Corporation
Clewiston Mill located in Clewiston, Florida

Dear Mr. Linero:

Thank you for sending the PSD permit application for U.S. Sugar Corporation - Clewiston Mill dated July 7, 1999. The application is for the increase in operations of the sugar refinery and Boiler No. 4. This proposed facility modifications include the addition of 3 conditioning silos and a sugar/starch bin, the increase in hours of operation of 3 existing vacuum systems and the VHP dryer, and the increase in operation of Boiler No. 4. The boiler currently combusts bagasse as its primary fuel and fires No. 6 fuel oil as its backup fuel which has a limit of 500,000 gallons/year. U.S. Sugar proposes to increase the operation of Boiler No. 4 from 2.7133×10^{12} Btu/yr (160 days/yr) to 2.88×10^{12} Btu/yr (200 days/yr). Total emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC) and particulate matter (PM/PM_{10}).

Based on our review of the application and supplemental information (fax from Golder Associates to Jeff Koerner, FDEP dated August 30, 1999) provided to EPA, we have the following comments regarding the BACT analyses. Modeling comments will be provided in a separate letter.

1. According to the information EPA received in the fax from Golder Associates, U.S. Sugar is proposing No. 6 fuel oil with a sulfur content of 0.7 percent as BACT to control SO_2 emissions from Boiler No. 4 (pg. 2 of fax). However, each operating season, U.S. Sugar plans to burn fuel oil from a common tank which normally receives 2.5% sulfur (S) fuel oil and replace the oil burned in Boiler No. 4 with 0.7% S fuel oil. We do not agree with this method of operation. Regardless of what sulfur limit is finally determined to be BACT, U.S. Sugar is required to burn that specific fuel oil in Boiler No. 4 and not some fuel oil mixture with a higher sulfur content. Also in the faxed information, U.S. Sugar provided economic analyses for four different operating scenarios. Following are our comments on each:

a. The first scenario (replacing used oil from common tank with 0.7% S No. 6 fuel oil) is unacceptable to EPA because it does not achieve the requirement of actually burning 0.7% S fuel oil in Boiler No. 4. The economic analysis was based on purchasing only 103,032 gallons/year of 0.7% S No. 6 fuel oil. If this scenario proposal is changed so that all four boilers burn 0.7% S No. 6 fuel oil from the common tank, it would be acceptable to EPA.

b. The second scenario (using 0.7% S No. 6 fuel oil and installing a new tank) is acceptable to EPA, but was declared economically infeasible by U.S. Sugar. There were several items of the cost analysis that were incorrect which, once corrected, will bring the cost effectiveness down to a lower level. First, the use of a 10% interest rate is not consistent with the interest rate of 7% which is used in the *OAQPS Control Cost Manual (fifth edition, 1996)*. It was stated on page 6 of the fax that U.S. Sugar wishes to use the actual cost of borrowing money; however, this is inconsistent with the *OAQPS Control Cost Manual*. On page 2-15 of the *OAQPS Control Cost Manual*, it specifically states that the interest rate (7%) is a pretax marginal rate of return on private investment and is in keeping with current OAQPS guidelines and the Office of Management and Budget recommendation for use in regulatory analysis. If a value of 10% is appropriate for U.S. Sugar, detailed documentation should be provided to EPA. Second, it is unreasonable to assume that the life of a tank is only 10 years. This value should be reconsidered or documentation of a 10-year life span should be provided. Third, the baseline emissions for this economic analysis were based on 1.5% S fuel oil; however, this fuel is not actually burned in Boiler No. 4. The baseline emissions should be based on the maximum sulfur content (2.5%S) of the fuel that is actually burned in Boiler No. 4. Finally, cost effectiveness (dollars per ton removed) is not the only factor that should be considered when determining economic feasibility. The total annualized cost of a project should also be considered. In this case, the annualized cost calculated by U.S. Sugar is only about $39,000 and will decrease when the items listed above are corrected.

c. The third scenario (using 0.5% S No. 2 fuel oil and installing a new tank and replacement burners) is acceptable to EPA, but declared economically infeasible by U.S. Sugar. The incorrect items listed above for the second scenario also apply to the third scenario and should reduce the cost effectiveness and annualized cost.

d. The fourth scenario (using 0.05% S No. 2 fuel oil and installing a new tank and replacement burners) is acceptable to EPA, but declared economically infeasible by U.S. Sugar. The incorrect items listed above for the second scenario also apply to the fourth scenario and should reduce the cost effectiveness and annualized cost.

2. As indicated on page 2-8 of the permit application, FDEP is proposing to allow excess emissions of the granular carbon regeneration furnace (GCRF) during startup for up to 2 hours in any 24-hour period. It is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should

be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

3. As indicated on page 5-5 of the permit application, U.S. Sugar cites limited testing of SO_2 emissions from burning bagasse in Boiler No. 4. Test data show emission ranges from 0.006 to 0.014 lb/mmBtu with an average emission rate of 0.008 lb/mmBtu. According to the faxed information provided to EPA, U.S. Sugar is now requesting a limit of 0.1 lb/mmBtu for SO_2 emissions when burning bagasse in Boiler No. 4. This limit is about 7.5 times the maximum emission rate shown from the testing. EPA believes this difference exceeds a reasonable margin for compliance, and we ask U.S. Sugar to reconsider this limit.

Thank you for the opportunity to comment on the U.S. Sugar - Clewiston Mill permit application. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

CC: J. Koerner, BAR
EPA
NPS
SD

Golder Associates Inc.

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

Golder Associates

September 13, 1999

9937515

RECEIVED
SEP 16 1999
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention: Jeffery Koerner, P.E

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL, INFORMATION SUBMITTAL NO. 3

Dear Mr. Koerner:

In follow up to our conversations last week with yourself, Cleve Holladay and Stan Krivo at EPA, this letter presents additional information regarding U.S. Sugar's PSD permit application to modify operation of Boiler No. 4 and expand the sugar refinery operation at their mill located in Clewiston, Florida. Presented in the attached tables are revised air dispersion modeling results for sulfur dioxide (SO_2). The revised modeling results reflect two changes in the SO_2 emissions inventories.

The first change is in the Clewiston mill inventory. In the case of the U.S. Sugar Clewiston mill, maximum SO_2 emissions occur with Boiler Nos. 1 through 4 burning the maximum amount of fuel oil, which is 16,200 gallons in a 3-hour period, and 88,800 gallons in a 24-hour period. For the 3-hour averaging time, Boiler Nos. 1 through 4 were modeled at their maximum fuel oil burning rates, as shown in Table 6-3 of the application. However, for the 24-hour averaging time, since the sum of the maximum individual boiler fuel oil usage rates is higher than these permitted totals, lower individual boiler fuel usage rates must be assumed for modeling purposes.

In order to be most conservative, maximum fuel oil burning in boilers with the lowest stack height and/or plume rise should be assumed, which then results in maximum SO_2 impacts. In the original modeling, fuel oil burning in Boiler Nos. 1 through 4 was prorated approximately equally over the four boilers based on maximum heat input on fuel oil. However, a different fuel oil burning scenario could result in higher SO_2 impacts. The stacks for Boiler Nos. 1, 2 and 3 are now each at 165 feet. Therefore, Boiler No. 4 has the lowest stack height (150 ft). Also, Boiler No. 3 is a smaller capacity boiler than Boiler Nos. 1 and 2, and therefore has a lower plume rise than Boiler Nos. 1 and 2. As a result, the modeling was re-run with Boiler Nos. 3 and 4 burning the maximum fuel oil they are capable of burning, with Boiler Nos. 1 and 2 burning the remainder of the total 88,800 gallons per 24-hour period. A revised Table 6-3 is attached which reflects these changes.

The second change to the SO_2 emissions inventory was in regards to the inventory for other sources. Several large sources of SO_2 emissions located beyond 60 km from U.S. Sugar were not included in the AAQS modeling. The modeling has been revised to include many of these sources, as shown in the revised Table 6-6 and Table 6-8 attached.

Revised AAQS impact results are attached reflecting these changes. Also, based on discussions with Cleve Holladay, higher background SO_2 concentrations were used in the AAQS modeling, based on the second highest 24-hour and 3-hour measured concentrations measured at the South Bay monitoring site in 1997. This site is rural in nature and not located near to any major sources of SO_2. A higher background PM_{10} concentration was also used, based on the second-highest measured PM_{10} concentration from the Clewiston monitoring site. The modeling results show compliance with all AAQS with these changes. Revised model input and output files for SO_2 have already been placed on the internet FTP site for your access.

Note that Tables 6-22 and 6-23 have not been revised, since the maximum PSD Class II increment consumption occurs approximately 20 to 30 km from U.S. Sugar Clewiston. Therefore, these tables are not expected to be affected by the changes to the U.S. Sugar SO_2 inventory.

Thank you for consideration of this information. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011
Seal

DB/jkk

CC: SD
EPA
NPS
File

Enclosures

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
National Park Service

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Table 6-3. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation @ 2.5% S Fuel Oil for Modeling Purposes (revised 09/07/99)

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
3	342.0 [c]	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	633.0	225.1	1,500	225.0	408.0	56,667	615.0	40.8 [d]	655.8	82.63 [e]
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	810.0	1,968.2	273,361	2,214.0	230.8	2,444.8	308.0
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	650	97.5	398.1	55,292	266.5	27.6	294.1	37.06
2	495.6	225.1	650	97.5	398.1	55,292	266.5	27.6	294.1	37.06
3	342.0	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	600.0	225.1	1,500	225.0	375.0	52,083	615.0	37.5 [d]	652.5	82.22 [e]
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,517.0	232.6	1,749.6	220.5

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions from lowest stacks. Boiler No. 4 has lowset stack @ 150 ft, followed by Boiler Nos. 1, 2 and 3 @ 165 ft each. Boiler No. 3 has lower plume rise than Boiler Nos. 1 and 2 due to lower total heat input.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

[e] For modeling purposes, this SO_2 emission rate is slightly higher than that shown in Table 2-1 for Boiler No. 4. This is due to not accounting for the differences in combustion efficiency between bagasse and fuel oil.

Note: Fuel Oil - 8.2 lb/gal
18,300 Btu/lb; 150,000 Btu/gal
2.5% sulfur
Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

Table 6-6 . Summary of Competing SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses (revised 9/9/99)

9937515a/02/tab6-6
9/13/99

			UTM Coordinates		Relative to USS Clewiston Mill				Maximum SO_2	Q,
			East	North	X	Y	Distance	Direction[a]	Emissions	Emission Threshold
APIS Number	Facility	County	(km)	(km)	(km)	(km)	(km)	(deg)	(TPY)	(Dist -53) x 20
52FTM260001	Everglades Sugar	Hendry	509.6	2954.2	3.5	-2.7	4.4	128	607	SIA
50PMB500086	Glades Correctional Institute	Palm Beach	523.4	2955.2	17.3	-1.7	17.4	96	98	SIA
52FTM260015	Southern Gardens Citrus	Hendry	487.6	2957.6	-18.5	0.7	18.5	272	409	SIA
50PMB500332	Okeelanta	Palm Beach	525.0	2937.4	18.9	-19.5	27.2	136	939	SIA
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	28.8	-3.6	29.0	97	2,555	SIA
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	32.7	11.2	34.6	71	2,698	SIA
52FTM500016	Osceola Farms	Palm Beach	544.2	2968.0	38.1	11.1	39.7	74	2,023	SIA
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	46.8	-11.7	48.2	104	954	SIA
50WPB430001	FPL -Martin	Martin	543.1	2992.9	37.0	36.0	51.6	46	93,788	SIA
50WPB430102	Bechtel Indiantown	Martin	545.6	2991.5	39.5	34.6	52.5	49	2,629	SIA
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	53.1	21.4	57.3	68	504	85.0
50WPB430007	Dickerson	Martin	569.5	2995.9	63.4	39.0	74.4	58	58	428.7
50WPB500234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	79.7	3.3	79.8	88	1,533	535.4
52FTM360119	Lee County Resource Recovery	Lee	424.0	2946.0	-82.1	-10.9	82.8	262	490	596.4
52FTM36	FPL - Fort Myers	Lee	422.1	2952.9	-84.0	-4.0	84.1	267	22,702	621.9
50WPB430021	Stuart Contracting	Martin	575.2	3006.8	69.1	49.9	85.2	54	100	644.7
50PMB500045	Lake Worth Utilities	Palm Beach	592.8	2943.7	86.7	-13.2	87.7	99	2,302	694.0
50PMB500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	88.1	3.7	88.2	88	73,475	703.6
50WPB062120	North Broward Resource Recovery	Broward	583.6	2907.6	77.5	-49.3	91.9	122	896	777.0
50WPB560003	Fort Pierce Utilities	St. Lucie	566.8	3036.3	60.7	79.4	99.9	37	2,708	938.9
50WPB062119	South Broward Resource Recovery	Broward	579.6	2883.3	73.5	-73.6	104.0	135	1,318	1020.3
50BRO060037	FPL -Lauderdale	Broward	580.1	2883.3	74.0	-73.6	104.4	135	47,858	1027.4
50BRO060036	FPL -Port Everglades	Broward	587.4	2885.3	81.3	-71.6	108.3	131	170,215	1106.7
50DAD130020	Tarmac	Dade	562.9	2861.7	56.8	-95.2	110.9	149	2,792	1157.1
50DAD130348	Dade Co. Resource Recovery	Dade	564.3	2857.4	58.2	-99.5	115.3	150	857	1245.4
30ORL310029	Vero Beach Power	St. Lucie	567.1	3056.5	61.0	99.6	116.8	31	18,496	1275.9
US Sugar Clewiston Mill Coordinates:			506.1	2956.9						

Proposed project's 24- and 3-hour emissions are significant to 53 and 60 km, respectively;
Emission imventory is limited to facilities within 103 km but includes major power plants at 104 and 108 km from the proposed project.

Table 6-8. Summary of Competing SO_2 Sources Included in the Air Modeling Analysis (revised 9/9/99)

APIS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
52FTM500016	Atlantic Sugar^a												
		Unit 1	ATLSUG1	27.4	1.83	346.0	17.97	10.85	10.85	CON	Yes	Yes	Yes
		Unit 2	ATLSUG2	27.4	1.83	350.0	23.36	10.85	10.85	CON	Yes	Yes	Yes
		Unit 3	ATLSUG3	27.4	1.83	350.0	21.56	10.50	10.50	CON	Yes	Yes	Yes
		Unit 4	ATLSUG4	27.4	1.83	344.0	25.16	10.76	10.76	CON	Yes	Yes	Yes
		Unit 5 PSD	ATLSUG5	27.4	1.68	339.0	19.24	11.84	11.84	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	18.9	1.92	506.0	12.70	-17.24	-17.24	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	ATLSUG2B	18.9	1.92	511.0	10.90	-22.50	-22.50	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	ATLSUG3B	21.9	1.83	522.0	17.50	-16.88	-16.88	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	ATLSUG4B	18.3	1.83	344.0	15.00	-10.76	-10.76	EXP	No	Yes	Yes
50WPB430102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD												
		Units 1&2	DCRRF12	76.2	3.66	405.4	15.86	26.41	12.32	CON	No	No	Yes
		Units 3&4	DCRRF34	76.2	3.66	405.4	15.86	26.41	12.32	CON	No	No	Yes
52FTM260001	Everglades Sugar^a Main Boiler		EVERGLAD	21.9	1.10	477.0	10.10	34.90	34.90	NO	Yes	No	No
50BRO060037	FPL - Lauderdale												
		CTs 1-4 PSD	LAUDU45	45.7	5.49	438.7	14.60	271.15	271.15	CON	Yes	No	Yes
		GT 1-12 (0.5% fuel oil)	LDGT1_12	13.7	2.37	733.2	114.31	552.80	552.80	NO	Yes	No	No
		GT 13-24 (0.5% fuel oil)	LDGT1324	13.4	4.75	733.2	28.43	552.80	552.80	NO	Yes	No	No
		4&5 PSD Baseline	FTLAU45B	46.0	4.27	422.0	14.63	-457.00	-457.00	EXP	No	No	Yes
50WPB430001	FPL Martin												
		Units 1&2	MART12	152.1	7.99	420.9	21.03	1743.79	1743.79		Yes	No	No
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes	Yes	Yes
		Diesl Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes	Yes	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes	Yes	Yes
50PMB500086	Glades Corr Institute		GLADCORR	9.8	0.40	389.0	11.28	2.82	2.82	NO	No	No	No
50WPB560003	Fort Pierce Utilities												
		Units 6&7	FTPIER67	45.7	2.19	408.2	12.50	77.87	77.87	NO	Yes	No	No
52FTM360002	FPL Fort Myers												
		Unit 1	FPLFMYU1	91.8	2.90	422.0	29.90	-585.50	-585.50	EXP	No	No	No
		Unit 2	FPLFMYU2	121.2	5.52	408.0	19.20	1334.0	-1334.0	EXP	No	No	No
		GT 1-12	FPLFMGTS	9.75	4.42	797.0	35.70	5152.4	5152.4	NO	Yes	No	No
		6 CTs, PSD	FPLFM6CT	38.1	5.79	377.6	21.43	3.86	3.86	CON	Yes	No	Yes
50PMB500045	Lake Worth Utilities												
		Unit 3	LAKWTHU3	38.1	2.13	408.2	7.71	103.95	103.95	NO	Yes	No	No
		Unit 5	LAKWTHU5	22.9	0.94	450.4	18.29	11.59	11.59	NO	Yes	No	No

Table 6-8. Summary of Competing SO_2 Sources Included in the Air Modeling Analysis (revised 9/9/99)

APIS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
52FTM360119	Lee County RRF PSD		LEECORRF	83.8	1.88	388.5	19.81	14.00	14.00	CON	No	No	Yes
50WPB062120	North Broward RRF PSD		NBCRRF	58.5	3.96	381.0	18.01	35.40	35.40	CON	No	No	Yes
50PMB500332	Okeelanta^a												
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	No	Yes	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	No	Yes	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	No	Yes	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	No	Yes	Yes
		Boiler 12 PSD Baseline	OKBLR12B	22.9	2.29	330.0	8.16	-20.58	-20.58	EXP	No	Yes	Yes
		Boiler 14 PSD Baseline	OKBLR14B	22.9	2.29	333.0	8.28	-20.03	-20.03	EXP	No	Yes	Yes
		Boiler 15 PSD Baseline	OKBLR15B	22.9	2.29	332.0	10.23	-16.79	-16.79	EXP	No	Yes	Yes
		Okeelanta Power Blrs 1,2,3^b	OKCOGEN	68.6	3.05	438.7	17.46	27.0	27.0	CON	Yes	Yes	Yes
52FTM500019	Osceola Farms^a												
		Unit 2	OSBLR2	27.4	1.52	339.0	18.63	17.12	17.12	CON	Yes	Yes	Yes
		Unit 3	OSBLR3	27.4	1.92	344.0	14.34	30.74	30.74	CON	Yes	Yes	Yes
		Unit 4	OSBLR4	27.4	1.83	344.0	16.53	17.12	17.12	CON	Yes	Yes	Yes
		Unit 5	OSBLR5	27.4	1.52	344.0	17.85	18.00	18.00	CON	Yes	Yes	Yes
		Unit 6	OSBLR6	27.4	1.92	339.0	18.25	33.39	33.39	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-5.07	-5.07	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-16.32	-16.32	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-7.26	-7.26	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-13.61	-13.61	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	OSBLR5B	22.0	1.52	342.0	12.12	-16.32	-16.32	EXP	No	Yes	Yes
50WPB500234	Palm Beach Co. Resource Recovery												
		1&2 PSD	PBCRRF	76.2	2.04	505.2	24.90	85.05	85.05	CON	No	No	Yes
50BR0060036	FPL Port Everglades												
		Units 1&2 at 2.5%s fuel oil	PTEVU12	104.5	4.27	415.9	26.72	1593.90	1593.90	NO	Yes	No	No
		Units 3&4 at 2.5%s fuel oil	PTEVU34	104.5	5.52	414.8	23.88	2772.00	2772.00	NO	Yes	No	No
		GT 1-12 (0.5% fuel oil)	PTEVGTS	13.4	4.75	733.2	28.43	530.70	530.70	NO	Yes	No	No
50WPB500234	Pratt & Whitney												
		Heater	PRATARCH	15.2	0.91	810.9	143.73	13.99	13.99	CON	No	No	Yes
		Boiler BO-12	PRATBO12	4.6	0.76	533.2	6.92	0.51	0.51	CON	No	No	Yes
50PMB500042	FPL Riviera												
		Units 3&4 at 2.5%s fuel oil	RIVU34	90.8	4.88	401.5	18.90	2113.65	2113.65	NO	Yes	No	No
50WPB062116	South Broward RRF PSD		SBCRRF	59.4	3.96	381.0	18.01	37.91	37.91	CON	No	No	Yes

Table 6-8. Summary of Competing SO_2 Sources Included in the Air Modeling Analysis (revised 9/9/99)

APIS Number	Facility	Units	Modeling ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s): 3-Hour	24-Hour	PSD Source? (EXP/CON)	Modeled in: AAQS	Class II	Class I
50FTM260015	Southern Gardens Citrus - PSD												
		Peel Dryer	SGARDDRY	38.1	1.16	338.7	9.41	5.29	5.29	CON	Yes	Yes	Yes
		Boilers 1-3	SGARDBLR	16.8	1.22	477.6	14.23	6.48	6.48	CON	Yes	Yes	Yes
52FTM500026	Sugar Cane Growers^a												
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes	Yes	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes	Yes	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes	Yes	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes	Yes	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	No	Yes	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	No	Yes	Yes
50DAD130020	Tarmac												
		Kiln 1	TARMC1	61.0	2.44	465.0	12.80	5.67	5.67		No	No	No
		Kiln 2 PSD Baseline	TARMC2B	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	No	No	Yes
		Kiln 3 PSD Baseline	TARMC3B	61.0	4.57	472.0	10.78	-2.76	-2.76	EXP	No	No	Yes
		Kiln 2 PSD	TABMC2P	61.0	2.44	422.0	9.10	24.57	24.57	CON	No	No	Yes
		Kiln 3 PSD	TARMC3P	61.0	4.57	450.0	11.04	51.43	51.43	CON	No	No	Yes
52FTM500061	US Sugar-Bryant^a												
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	45.70	45.70	CON	Yes	Yes	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	109.50	109.50	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	No	Yes	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	No	Yes	Yes
	US Sugar - Clewiston - PSD Baseline												
		Unit 1 PSD Baseline	BRL1B	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	BLR2B	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	BLR3B	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	No	Yes	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	No	Yes	Yes

a Facilities or sources within facilities that operate only during the November 1 through May 31 crop season

b.Sugar mill sources that operate all year

Note: EXP = PSD expanding source.

Table 6-19. Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analyses (Revised 9/13/99)

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2				
Annual				
	30.9	300	1200	87123124
	32.5	270	1200	88123124
	34.7	310	1200	89123124
	36.9	270	1200	90123124
	34.4	300	1200	91123124
H2H 24-Hour				
	237	310	1200	87080724
	243	310	1200	88040324
	223	320	900	89060424
	227	250	900	90042024
	224	260	1200	91102424
H2H 3-Hour				
	710	310	1200	87061415
	806	310	900	88090912
	740	310	900	89061212
	714	310	900	90061815
	911	310	900	91072412
PM_{10}				
Annual				
	7.9	270	900	87123124
	8.6	270	900	88123124
	9.0	310	900	89123124
	9.9	270	900	90123124
	8.6	300	900	91123124
H2H 24-Hour				
	75	270	900	87123124
	70	310	1200	88112024
	66	320	900	89060424
	68	250	900	90042024
	69	260	900	91102424
CO				
H2H 8-Hour				
	4,183	310	900	87061416
	4,501	280	1200	88032408
	4,389	310	900	89041416
	4,239	250	900	90022708
	4,742	310	900	91043016
H2H 1-Hour				
	8,533	320	600	87090213
	8,679	320	600	88090413
	8,901	320	600	89061511
	9,236	330	527	90080511
	9,726	40	595	91061812

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler No. 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20. Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis (Revised 9/13/99)

Averaging Time	Concentration ($\mu g/m^3$)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
	Total	Modeled	Background	Direction (degree)	Distance (m)		
SO_2							
Annual	40	35	5	314	1000	89123124	60
	42	37	5	270	1100	90123124	
	40	35	5	300	1100	91123124	
H2H 24-Hour	257	244	13	310	1100	88040324	260
	239	226	13	260	1300	91102524	
H2H 3-Hour	856	809	47	310	800	88090912	1300
	959	912	47	310	800	91070618	
PM_{10}							
Annual	32	9	23	316	900	89123124	50
	33	10	23	272	900	90123124	
H2H 24-Hour	117	78	39	272	800	87123124	150
	109	70	39	310	1300	88112024	
	109	70	39	260	1000	91102424	
CO							
H2H 8-Hour	7,962	4,532	3,430	280	1100	88032408	10000
	8,310	4,880	3,430	312	700	91043016	
H2H 1-Hour	15,441	9,726	5,715	40	595	91061812	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91
[b] Relative to Boiler No. 4 Stack Location

Notes
YYMMDDHH = Year, Month, Day, Hour Ending
H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-21 . Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis
(Revised 9/13/99)

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	1.8	270	20000	87123124
	2.4	270	20000	88123124
	1.4	270	20000	89123124
	2.7	70	30000	90123124
	1.9	270	20000	91123124
H2H 24-Hour				
	30	70	30000	87112324
	28	70	30000	88013024
	23	70	30000	89021624
	31	70	30000	90031024
	28	70	30000	91120724
H2H 3-Hour				
	70	70	30000	87050318
	79	70	30000	88050324
	69	70	30000	89021718
	73	70	30000	90011821
	84	70	30000	91020509
PM_{10}				
Annual				
	<0	0	0	87123124
	0.03	340	1200	88123124
	<0	0	0	89123124
	0.03	330	1500	90123124
	0.03	340	1200	91123124
H2H 24-Hour				
	6.5	360	1200	87071924
	8.6	330	900	88062824
	7.0	320	900	89070224
	7.7	310	900	90082724
	10.4	310	900	91072424

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91
[b] Relative to Boiler No. 4 Stack Location

Notes:
YYMMDDHH = Year, Month, Day, Hour Ending
H2H = Highest, 2nd-Highest Concentration in 5 years.
PSD = Prevention of Significant Deterioration

Table 6-24. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment ($\mu g/m^3$)
Annual					
	0.18	545000	2848600	87123124	2
	0.19	535000	2848600	88123124	
	0.15	550300	2848600	89123124	
	0.23	545000	2848600	90123124	
	0.14	540000	2848600	91123124	
H2H 24-Hour					
	2.1	550300	2848600	87102324	5
	3.0	545000	2848600	88022824	
	2.1	545000	2848600	89041724	
	2.6	540000	2848600	90111624	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	14.0	545000	2848600	87031421	25
	15.7	535000	2848600	88021621	
	15.8	543500	2824600	89011003	
	18.0	540000	2848600	90012224	
	14.5	553000	2796500	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:

PSD = Prevention of Significant Deterioration

YYMMDDHH = Year, Month, Day, Hour Ending

UTM = Universal Transverse Mercator

H2H = Highest, 2nd-Highest

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION) 3.

Jeffery Koerner

2. 5.

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE _____

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

X FOR YOUR FILES

COMMENTS:

Tallahassee office / DEP Air Program Mail Station 5505

NOTE: THIS WAS CUST IN OUR MAIL SYSTEM. IT WAS RECEIVED BY FAX ON 8-30-99. JFK

FROM: WRBSED DATE 12/23/99 PHONE: 2765659.

DEP 15-026 (12/93)

Maria

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

August 23, 1999

RECEIVED 9937515
DEC 27 1999
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

m.Sta. 5505

Attention: Jeffery Koerner, P.E.

RE: U.S. SUGAR – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
RESPONSE TO REQUEST FOR INFORMATION NO. 2

Dear Mr. Koerner:

This letter is in response to your draft completeness letter e-mailed to me on August 16 concerning U.S. Sugar's PSD Permit Application to modify operation of Boiler No. 4 and expand the sugar refinery operation at their mill located in Clewiston, Florida. This letter is organized in the same manner as your draft completeness letter. Responses to each item are presented below, numbered according to the original question numbers.

4. An analysis of the cost effectiveness of reducing SO_2 emissions by buying fuel oil with a sulfur content of less than 1.5 percent is presented in the attached tables. A summary of fuel costs and calculated emission rates for several scenarios is presented in Table 4-1. A cost efficiency evaluation of the following SO_2 emissions reduction options is presented in Tables 4-2 through 4-5:

    1. Replacing the current 1.5 percent sulfur No. 6 fuel oil burned with 0.7-percent sulfur No. 6 fuel oil, and storing it in the existing common storage tank used to supply Boiler Nos. 1, 2, 3, and 4.
    2. Replacing the current 1.5-percent sulfur No. 6 fuel oil burned with 0.7 percent sulfur No. 6 fuel oil, and storing it in a new storage tank.
    3. Replacing the current No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.5 percent. This option would require a new storage tank (No. 6 and No. 2 fuel oil are not miscible) and replacement of the current oil burners in Boiler No. 4, which are not capable of firing No. 2 fuel oil.
    4. Replacing the current No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.05 percent. This option would also require a new storage tank and burner replacement.

    It is noted that, for cost effectiveness calculations, the top-down BACT guidance document (draft) allows the use of past historical operation and emissions. Thus,

even though Boiler No. 4 is permitted to burn 500,000 gal/yr of fuel oil, actual historic operation (last 3 years) indicates only about 100,000 gal/yr of fuel oil is burned. The actual fuel oil consumption and resulting SO_2 emissions were used for the cost effectiveness calculations.

The results of the analysis are shown in Table 4-6. Clearly, the cost efficiencies of the two options involving switching to No. 2 fuel oil are unreasonable (over $8,000 per ton of SO_2 removed). This is due to the relatively small reduction in SO_2 emissions (approximately 12 tons) measured against the capital cost of a new storage tank and replacement of the burners ($395,000). Option 2 was included at the request of FDEP. The only difference between Option 1 and Option 2 is that Option 1 employs the use of the existing common storage tank, while Option 2 includes installation of a new storage tank at a substantial cost to U.S. Sugar. It is emphasized that the installation of a new storage tank is not justified as it affords no additional SO_2 control over that afforded by Option 1, but increases the cost of SO_2 removal by nearly $5,000 per ton.

Given the costs associated with switching Boiler No. 4 to No. 2 fuel oil or adding another No. 6 fuel oil tank, U.S. Sugar requests that BACT be determined to be the use of No. 6 fuel oil with a sulfur content of 0.7 percent.

The potential reductions in SO_2 emissions that may be obtained by lowering the overall sulfur content of fuel oil fired in the common fuel oil tank was also analyzed. Based on the last 2 years of operation for Boiler Nos. 1 through 4, total fuel oil burning averaged 970,000 gal/yr, sulfur content averaged 2.3 percent, and SO_2 emissions averaged 192 TPY. Switching to 0.7-percent sulfur No. 6 fuel oil would, therefore, lower actual SO_2 emissions by about 134 TPY. The cost of such reduction, based on the information presented in Tables 4-1 through 4-6, would be approximately $700/ton of SO_2 removed (similar to Option 1 in the above analysis). It is cautioned, however, that the PSD rules do not bring the other boilers under the review requirements. The other boilers are not part of the proposed "modification". Only the modification itself (Boiler No. 4 and the sugar refinery) is subject to BACT.

In addition, the proposed project no longer results in an increase in SO_2 emissions of 350 TPY. Attached are revised tables which show the maximum short-term emissions (Table 2-1), the future maximum annual emissions (Table 2-2), the current baseline emissions (Table 3-3) and the net increase in emissions (Table 3-4) for Boiler No. 4. Also attached is a revised Table 1-1, which shows the total net increase in emissions for Boiler No. 4 and the sugar refinery. Tables 2-1 and 2-2 have been revised to reflect the 0.7-percent sulfur fuel oil, as well as a lower SO_2 limit for bagasse firing (refer to Item 5 below). These changes affect SO_2 and sulfuric acid mist emissions. Baseline emissions (Table 3-3) have been revised to correct some minor typographical errors. These changes are reflected in the revised Tables 1-1 and 3-4. Also attached are revised permit application form pages, which reflect these changes.

5. SO_2 removal is inherent to the process of combusting bagasse. The fly ash produced during bagasse firing is alkaline in nature and acts as a dry scrubbant adsorbing SO_2

from the exhaust stream. The fly ash, along with the adsorbed SO_2, is then removed by the scrubber. The alkaline nature of the fly ash also maintains the pH of the scrubber water between 5 and 8, further enhancing SO_2 removal. Evidence of the inherent removal of SO_2 is apparent on review of the SO_2 stack test results for Boiler No. 7 presented in our last correspondence. The only control equipment employed on Boiler No. 7 is an ESP, yet SO_2 removal efficiencies average 96 percent. As shown in the stack tests for Boiler No. 4, also presented in our last response, the average removal efficiency with the addition of a scrubber only increases to 97 percent. As such, monitoring the pH of the scrubber water is not necessary as an indicator of the efficiency of SO_2 control. It is noted that for air dispersion modeling purposes, a 75-percent SO_2 removal efficiency was assumed for Boiler Nos. 1, 2, and 3 for bagasse firing.

To the best of our knowledge, specific stack tests have not been performed to quantify the potential control effectiveness of maintaining or enhancing the alkaline scrubbing media. Based on the SO_2 stack tests performed on the wet scrubber sources at Clewiston, U.S. Sugar is willing to reduce the allowable SO_2 emission limit for bagasse to 0.1 lb/MMBtu, which allows an adequate safety margin above the actual test results. U.S. Sugar is also willing to conduct a stack test to once again verify that this emission limit is being met.

10. See our response to Item 5.

12. Using information from the last five stack tests the actual range for the scrubber pressure drop has historically ranged from 9 to 10 inches H_2O. Based on this actual operation, for which compliance with the particulate matter (PM) emission limit was demonstrated, the optimum range for pressure drop is 7 to 12 inches H_2O. As you have discovered in the Boiler No. 4 permit files, the scrubber manufacturer (Joy) based their PM emission guarantee on a pressure drop from 5 to 9 inches H_2O. U.S. Sugar, based on actual operating experience, typically operates slightly above this range to obtain better performance and improved PM removal.

13. As described in our previous response, there is no historic boiler oxygen concentration level data for Boiler No. 4. The boiler is not equipped with an oxygen monitor. Oxygen at the stack is measured during stack testing, but this oxygen level is not representative of boiler oxygen levels due to significant air infiltration into the exhaust gases between the boiler and the stack. The other boilers at the Clewiston mill that are similar to Boiler No. 4 (Boiler Nos. 1, 2, and 3) also do not have oxygen monitors.

    Boiler No. 8 at the Sugar Cane Growers Cooperative has an oxygen meter, and the O&M plan for the boiler requires that an alarm be triggered if the oxygen level in the boiler drops below 4 percent. The time the boiler operates with less than 4-percent oxygen must be logged. The O&M plan states that the goal is to maintain the flue gas oxygen content at or above 4 percent, to the extent practical without sacrificing proper boiler operation and consistent with meeting steam demands.

In consideration of the Department's desire to implement methods of potentially lowering CO and VOC emissions, U.S. Sugar is willing to install a flue gas oxygen monitor on Boiler No. 4 during the upcoming crop season. The flue gas oxygen content will be recorded on an hourly basis. It is proposed that data collection continue for three crop seasons, which will include stack testing for CO and VOC emissions in each of these three seasons. After this data collection, the data will be evaluated and an appropriate range of oxygen level established for the boiler. The oxygen monitor will then be configured to trip an alarm whenever the oxygen content falls outside the established range. Corrective actions would then be implemented to bring the oxygen level within the established range, consistent with proper boiler operation and meeting steam production demands.

In addition, U.S. Sugar agrees to lower their proposed VOC emission limit from the previous requested level of 1.5 lb/MMBtu to a more realistic 0.5 lb/MMBtu. Although there is no recent VOC test data for this boiler, U.S. Sugar believes this is a reasonable limit based on the boiler design. Revised calculation tallies are attached.

16. The GCRF has never been tested for SO_2 emissions, and such testing is not a requirement of the current permit. However, as we discussed, the SO_2 emissions are solely due to fuel oil combustion in the furnace and, therefore, there is no need to perform stack testing (fuel analysis should suffice). The critical parameters for operation of the afterburner on the GCRF is afterburner temperature, while pressure drop is critical on the venturi scrubber.

21. We are pursuing approval of the ISC-PRIME model through discussions with Cleve Holladay and EPA Region IV.

22. The questions received to date from the National Park Service (NPS) so far are answered below.

In regards to the comment that we have not provided a top-down BACT analysis for each pollutant, nor suggested a method to substantially reduce such emissions the following is provided. For SO_2, the response to Question 4 above should provide you with this information. For CO and VOC, there are no known or proven methods for reducing these emissions from an existing boiler, other than proper boiler operation. The response to Question 13 above provides a plan for acquiring to data to ultimately reduce emissions. However, data must first be collected and evaluated prior to implementing any specific actions. In regards to NO_x, emissions from this boiler are already very low (NO_x emissions averaged 0.08 lb/MMBtu) and do not warrant further reduction. Any measures to reduce CO and VOC emissions will likely increase NO_x emissions.

Responses to NPS Comments:

PSD Applicability

Baseline (actual) emission rate calculations for all regulated pollutants emitted from Boiler No. 4 were presented in Table 3-3 of the PSD permit application. A copy of Table 3-3 is

attached for your review. These emission rate calculations are based on average operation of Boiler No. 4 during 1997 and 1998.

Due to the short operational history (less than 2 years), the sugar refinery and its proposed expansion were considered a new source in the PSD permit application. As such, emissions of VOC and PM associated with the proposed expansion of the sugar refinery were addressed in the PSD analysis.

In regards to emissions from the sugar mill and bagasse handling system, refer to the response to FDEP Comment 1 above.

Best Available Control Technology

Particulate Matter

The cost effectiveness (dollars per ton of PM removed) of an ESP is significantly less for Boiler No. 7 than for Boiler No. 4 for one main reason: Boiler No. 7 was a new boiler and, therefore, its uncontrolled emissions were the basis of the cost effectiveness calculations. Boiler No. 4 is an existing source with controlled PM emissions averaging 0.12 lb/MMBtu. This is the starting point for its cost effectiveness calculations, not uncontrolled emissions. As such, annual emissions for cost effectiveness calculations for Boiler No. 7 are much higher than for Boiler No. 4.

Other factors which render the Boiler No. 7 cost effectiveness lower are: 1) Boiler No. 7 is permitted to operate on full load year around (Boiler No. 4 will be limited to an equivalent of 200 days/yr operation); 2) Boiler No. 7 has a higher heat input rate than Boiler No. 4 (812 compared to 633 MMBtu/hr); and 3) because of design and operation with a wet scrubber, Boiler No. 4 has a significantly larger exhaust flow (344,800 compared to 254,587 acfm) that increases the capital cost of an ESP from $2,000,000 to $2,700,000. Both these factors lower the cost efficiency of an ESP making it economically feasible for Boiler No. 7, but not for Boiler No. 4. Boiler No. 7 is certainly not similar to Boiler No. 4, in design or operation and, therefore, separate cost analysis are warranted.

The NPS also had several comments concerning validity of the cost analysis presented to rule out an ESP for Boiler No. 4 based on economic feasibility. These concerns are addressed below:

1. A wet cyclone was included in the cost analysis because the existing impingement scrubber would need to be replaced due to excessive moisture in the flue gas, which would interfere with the operation of an ESP.
2. Working capital costs are less than 1 percent of the total capital investment and, therefore, the costs are not significant.
3. The estimate that an operator will be required for 8 hours per day is based on operational experience for Boiler No. 7; the only known application of an ESP on a bagasse fired boiler. This figure is due to the lack of any previous operating experience with an ESP in the sugar industry. As the OAQPS cost manual is intended as a guide in lieu of situation-specific information, U.S. Sugar's

operational experience is a better indicator of the time and effort required to operate and maintain an ESP on a bagasse fired boiler.

4. The capital cost recovery factor of 7 percent presented in the OAQPS cost manual is used to illustrate example cost calculations. More appropriately, the actual cost of borrowing money should be used, which in this case was assumed to be 10 percent and is representative of current economic conditions.
5. The OAQPS manual indicates a range of useful equipment life for an ESP of 5 to 40 years. Due to the lack of industry data for a ESP on a bagasse fired boiler and the maintenance/replacement costs already incurred for the ESP on Boiler No. 7, a conservative estimate of 10 years was used for the equipment life of the ESP in this cost analysis.
6. The efficiency of the ESP for both cases (Boiler No. 4 and Boiler No. 7) were based on the vendor guarantee of 0.03 lb/MMBtu, although this level of emissions was not achievable on Boiler No. 7 until the wet cyclone was added preceding the ESP. The only difference is that for Boiler No. 4 the current emissions are already down to 0.12 lb/MMBtu, but an ESP would still only achieve a 0.03 lb/MMBtu emission level, since the existing scrubber would be replaced.

Nitrogen Oxides

As stated in the permit application, through good combustion practices, U.S. Sugar achieves an average NO_x emission rate of 0.08 lb/MMBtu. However, U.S. Sugar cannot accept a BACT limit based on average emissions, since this limit will have to be achieved on a continuous basis. Review of the NO_x test data presented in Appendix C of the application shows that stack test results vary from 0.03 to 0.16 lb/MMBtu. Given this variability in NO_x emissions, U.S. Sugar requests an emission limit of 0.25 lb/MMBtu as previously determined as BACT for this unit.

Sulfur Dioxide

Refer to Items 4 and 5 above for a response to this comment.

Thank you for consideration of these responses. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/jkk

Enclosures
cc: Don Griffin
Bill Wehrum
\\GATORBAIT\MISCDATA\DATA\DP\Projects\9937515a\01\#01ltr.dot

Table 4-1. Fuel Cost and SO_2 Emission Rate Analysis

Fuel Type/ Sulfur Content	Unit Cost ($/gal)	Usage (gal/yr)		Annual Cost ($/yr)	Cost Increase ($/yr)	SO_2 Emission Rate[a] (TPY)
No. 6 Fuel Oil						
1.5% Sulfur	0.5750	102,350	[b]	58,851	--	12.6
0.7% Sulfur	0.6179	103,032	[c]	63,659	4,808	5.7
No. 2 Fuel Oil						
0.5% Sulfur	0.6607	109,661	[c]	72,454	13,603	3.7
0.05% Sulfur	0.6845	113,722	[c]	77,846	18,994	0.4

Notes:
1. All prices based on Coastal Fuels Marketing, Inc.'s current prices (FOB)

Footnotes:

[a] Based on the following information:

Fuel Type	Sulfur Content (% by wt.)	Heat Content (Btu/gal)	Density (lb/gal)
No. 2 Fuel Oil	0.5	140,000	6.83
	0.05	135,000	6.83
No. 6 Fuel Oil	1.5	151,000	8.22
	0.7	150,000	7.94

[b] Based on actual average usage of No. 6 fuel oil in 1996, 1997, and 1998 of 96,968, 90,686, and 119,395 gallons, respectively.

[c] Gallons needed for equivalent heat input to No. 6 fuel oil with a sulfur content of 1.5%.

Table 4-2. Cost Effectivenéss of No. 6 Fuel Oil (0.7% Sulfur Content With a Common Tank) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	Not applicable	0
INDIRECT CAPITAL COSTS (ICC):[b]		
Indirect Installation Costs	Not Applicable	
(a) Engineering	Not Applicable	
(b) Construction & Field Expenses	Not Applicable	
(c) Construction Contractor Fee	Not Applicable	
(d) Contingencies	Not Applicable	
Other Indirect Costs		
(a) Startup & Testing	Not Applicable	
(b) Working Capital	Not Applicable	
Total ICC:		0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	0
DIRECT OPERATING COSTS (DOC):[c]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 6 Fuel (0.7% Sulfur Content)	See Footnote "d"	4,808
Total DOC:		4,808
INDIRECT OPERATING COSTS (IOC):[c]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	0
Insurance	1% of total capital investment	0
Administration	2% of total capital investment	0
Total IOC:		0
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	0
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	4,808
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 6 FUEL OIL (TPY):	103,032 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	5.7
REDUCTION IN SO_2 EMISSONS (TPY):		6.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	697

Footnotes:

[a] All direct installation costs are included in basic price.

[b] All indirect installation costs are included in basic price.

[b] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[d] Increase in fuel cost associated with buying No. 6 fuel oil with a sulfur content of 0.7% ($0.6179/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 103,032 gallons per year.

Table 4-3. Cost Effectiveness of No. 6 Fuel Oil (0.7% Sulfur Content With a New Tank) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	170,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	170,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 6 Fuel (0.7% Sulfur Content)	See Footnote "e"	4,808
Total DOC:		4,808
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	1,700
Insurance	1% of total capital investment	1,700
Administration	2% of total capital investment	3,400
Total IOC:		6,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	27,659
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	39,267
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 6 FUEL OIL (TPY):	103,032 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	5.7
REDUCTION IN SO_2 EMISSONS (TPY):		6.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	5,691

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on actual installed cost of $170,000 for a similar storage tank installed in 1996..

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 6 fuel oil with a sulfur content of 0.7% ($0.6179/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 103,032 gallons per year.

Table 4-4. Cost Effectiveness of No. 2 Fuel Oil (0.5% Sulfur Content With New Tank and Burners) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	395,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	395,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator	$17/hr; 200 days/yr @ 8 hrs/day	0
Supervisor	15% of operator cost	0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.5% Sulfur Content)	See Footnote "e"	13,603
Total DOC:		13,603
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	3,950
Insurance	1% of total capital investment	3,950
Administration	2% of total capital investment	7,900
Total IOC:		15,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	64,267
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	93,670
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur Content of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 2 FUEL OIL (TPY):	109,661 gallons No. 2 Fuel Oil with a Sulfur Content of 0.5% by weight	3.7
REDUCTION IN SO_2 EMISSONS (TPY):		8.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	10,525

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on an actual installed cost of $170,000 for a storage tank and a vendor quote of $225,000 for burner replacement (installed).

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.5% ($0.6607/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 109,661 gallons per year.

Table 4-5. Cost Effectiveness of No. 2 Fuel Oil (0.05% Sulfur Content With New Tank and Burners) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	395,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	395,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor		0
Materials		0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.05% Sulfur Content)	See Footnote "e"	18,994
Total DOC:		18,994
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	3,950
Insurance	1% of total capital investment	3,950
Administration	2% of total capital investment	7,900
Total IOC:		15,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	64,267
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	99,061
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur Content of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 2 FUEL OIL (TPY):	113,722 gallons No. 2 Fuel Oil with a Sulfur Content of 0.05% by weight	0.4
REDUCTION IN SO_2 EMISSONS (TPY):		12.2
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	8,120

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on an actual installed cost of $170,000 for a storage tank and a vendor quote of $225,000 for burner replacement (installed).

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.05% ($0.6845/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 113,723 gallons per year.

Table 4-6 Summary of the Cost Effectiveness of SO_2 Control Options

Description of Control Option	Annualized Cost ($/yr)	Maximum SO_2 Emission Rate (TPY)	Reduction in SO_2 Emission Rate[a] (TPY)	Cost Effectiveness ($/ton removed)
Replace No. 6 Fuel Oil (1.5% S) with No. 6 Fuel Oil (0.7% S) Stored in the Common Storage Tank	4,808	5.7	6.9	697
Replace No. 6 Fuel Oil (1.5% S) with No. 6 Fuel Oil (0.7% S) Stored in a New Storage Tank	39,267	5.7	6.9	5,691
Replace No. 6 Fuel Oil (1.5% S) with No. 2 Fuel Oil (0.5% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	93,670	3.7	8.9	10,525
Replace No. 6 Fuel Oil (1.5% S) with No. 2 Fuel Oil (0.05% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	99,061	0.4	12.2	8,120

Footnote:

[a] Based on a baseline SO_2 emission rate of 12.6 TPY.

Table 2-1. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (revised 8/23/99)

Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceuos Fuel			
Particulate Matter (PM)	0.15	1	633	600	95.0	90.0
Particulate Matter (PM10)	0.14	2	633	600	88.3	83.7
Sulfur dioxide	0.1	3	633	600	63.3	60.0
Nitrogen oxides	0.25	4	633	600	158.3	150.0
Carbon monoxide	6.5	1	633	600	4,114.5	3,900.0
VOC	0.5	5	633	600	316.5	300.0
Sulfuric Acid Mist	0.006	6	633	600	3.9	3.7
Lead	4.45E-04	7	633	600	0.28	0.27
Mercury	3.8E-05	8	633	600	0.0241	0.0228
Beryllium	--	7	633	600	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	225	--	22.5	22.5
Particulate Matter (PM10)	0.10	9	225	--	22.5	22.5
Sulfur dioxide (b)	2.73	10	225	--	615.0	615.0
Nitrogen oxides	0.31	11	225	--	69.8	69.8
Carbon monoxide	0.033	11	225	--	7.5	7.5
VOC	0.0019	11	225	--	0.4	0.4
Sulfuric Acid Mist	0.044	6	225	--	9.9	9.9
Lead	1.01E-05	11	225	--	2.27E-03	2.27E-03
Mercury	7.53E-07	11	225	--	1.70E-04	1.70E-04
Beryllium	1.85E-07	11	225	--	4.17E-05	4.17E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			530	499	68.3	63.6
Particulate Matter (PM10)			530	499	65.1	60.7
Sulfur dioxide			530	499	645.6	642.4
Nitrogen oxides			530	499	146.2	138.2
Carbon monoxide			530	499	1,993.3	1,787.2
VOC			530	499	153.2	137.3
Sulfuric Acid Mist			530	499	11.8	11.6
Lead			530	499	0.14	0.12
Mercury			530	499	0.012	0.011
Beryllium			530	499	4.17E-05	4.17E-05
			Maximum Any Combination			
Particulate Matter (PM)					95.0	90.0
Particulate Matter (PM10)					88.3	83.7
Sulfur dioxide					645.6	642.4
Nitrogen oxides					158.3	150.0
Carbon monoxide					4,114.5	3,900.0
VOC					316.5	300.0
Sulfuric Acid Mist					11.8	11.6
Lead					0.28	0.27
Mercury					0.0241	0.0228
Beryllium					4.17E-05	4.17E-05

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 300,000 lb/hr at 600 psig, 750 F.
Maximum 6-hour average activity factor based on steam production rate of 285,000 lb/hr at 600 psig, 750 F.
Enthalpy of steam = 1,378 Btu/lb. Enthalpy of feedwater = 218 Btu/lb. Net enthalpy = 1,160 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (300,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 168 MMBtu/hr
Required heat input to boiler from bagasse = 168 MMBtu/hr / 55% eff. = 305.5 MMBtu/hr
Total heat input required = 225 + 305.5 = 530 MMBtu/hr
Max 24-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (285,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 150.6 MMBtu/hr
Required heat input to boiler from bagasse = 150.6 MMBtu/hr / 55% eff. = 273.8 MMBtu/hr
Total heat input required = 225 + 274 = 499 MMBtu/hr

(b) The SO2 emission factor reflects the maximum sulfur content (2.5%) which could exist in the common plant No. 6 fuel oil tank. Boiler Nos. 1, 2 and 3 are permitted to burn up to 2.5% sulfur fuel oil, while the amount of fuel oil burned in Boiler No. 4 during a crop season will be replaced in the plant common fuel oil tank with fuel oil containing no more than 0.7% sulfur.

References

1. Current BACT permit limit for Clewiston.
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Proposed BACT limit, based on actual stack testing on Clewiston boilers. Equivalent to 0.1% sulfur content of bagasse (wet), 3,600 Btu/lb(wet); and 82% removal in wet scrubber.
4. Equivalent to current permit limit for Clewiston Boiler No. 4.
5. Proposed permit limit.
6. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
7. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
8. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
9. Assumed as 100% of PM emissions.
10. Based on 2.5% S fuel oil; 150,000 Btu/gal; 8.2 lb/gal; assumes 100% conversion of sulfur to SO2.
11. Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Multiple Fuel Combustion:
= {(Bagasse Activity Factor - Fuel Oil Activity Factor) x Bagasse Emission Factor}
+ (Fuel Oil Activity Factor x Fuel Oil Emission Factor)

Table 2-2. Future Maximum Annual Emissions, Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	Bagasse Firing			Fuel Oil Firing			TOTAL EMISSIONS (TPY)
	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	
Particulate Matter (PM)	0.15 lb/MMBtu	2,880,000	216.0	0.1 lb/MMBtu	0	0.0	216.0
PM10	0.14 lb/MMBtu	2,880,000	201.6	0.1 lb/MMBtu	0	0.0	201.6
Sulfur Dioxide	0.1 lb/MMBtu	2,805,000	140.3	0.74 lb/MMBtu (b)	75,000	27.8	168.0
Nitrogen Oxides	0.25 lb/MMBtu	2,805,000	350.6	0.31 lb/MMBtu	75,000	11.6	362.3
Carbon Monoxide	6.5 lb/MMBtu	2,880,000	9,360.0	0.033 lb/MMBtu	0	0.0	9,360.0
Volatile Organic Compounds	0.5 lb/MMBtu	2,880,000	720.0	0.0019 lb/MMBtu	0	0.0	720.0
Sulfuric Acid Mist	0.006 lb/MMBtu	2,880,000	8.8	0.045 lb/MMBtu	0	0.0	8.8
Lead	4.45E-04 lb/MMBtu	2,880,000	0.6	1.01E-05 lb/MMBtu	0	0.0	0.64
Mercury	3.80E-05 lb/MMBtu	2,880,000	0.1	7.53E-07 lb/MMBtu	0	0.0	0.055
Beryllium	--	2,805,000	--	1.85E-07 lb/MMBtu	75,000	6.94E-06	6.94E-06

(a) Total heat input based on total steam production of 1.368E+09 lb steam/yr, 1,160 Btu/lb steam and 55% thermal efficiency.
Fuel oil considered where worst case emission factor is due to oil burning. Maximum fuel oil burning is 500,000 gal/yr, equivalent to 75,000 MMBtu/yr.
(b) Represents maximum sulfur content of 0.7% for fuel oil to be replaced in the plant common fuel oil tank.

References: Refer to Table 2-1 for emission factors.

Table 3-3. Baseline Emissions for Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	Bagasse Firing				Fuel Oil Firing				TOTAL
	Emission Factor	Ref.	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Ref.	Heat Input (b) (MMBtu/yr)	Emissions (TPY)	EMISSIONS (TPY)
Particulate Matter (PM)	0.12 lb/MMBtu	1	1,661,913	99.7	0.1 lb/MMBtu	4	15,816	0.79	100.5
PM10	0.112 lb/MMBtu	2	1,661,913	93.1	0.1 lb/MMBtu	9	15,816	0.79	93.9
Sulfur Dioxide	0.008 lb/MMBtu	1	1,661,913	6.6	1.67 lb/MMBtu	5	15,816	13.21	19.9
Nitrogen Oxides	0.082 lb/MMBtu	1	1,661,913	68.1	0.31 lb/MMBtu	10	15,816	2.45	70.6
Carbon Monoxide	6.36 lb/MMBtu	1	1,661,913	5,284.9	0.033 lb/MMBtu	10	15,816	0.26	5,285.1
Volatile Organic Compounds	0.25 lb/MMBtu	3	1,661,913	207.7	0.0019 lb/MMBtu	10	15,816	0.015	207.8
Sulfuric Acid Mist	0.00049 lb/MMBtu	6	1,661,913	0.4	0.10 lb/MMBtu	6	15,816	0.81	1.2
Lead	4.45E-04 lb/MMBtu	7	1,661,913	0.37	1.01E-05 lb/MMBtu	10	15,816	7.99E-05	0.37
Mercury	8.00E-06 lb/MMBtu	8	1,661,913	6.65E-03	7.53E-07 lb/MMBtu	10	15,816	5.95E-06	6.65E-03
Beryllium	--	7	1,661,913	0.0	1.85E-07 lb/MMBtu	10	15,816	1.46E-06	1.46E-06

(a) Based on actual steam production during 1997 and 1998, and actual steam enthalpies during stack tests.
(b) Based on average fuel oil usage during last two crop seasons of 90,686 gal (1997) and 119,395 gal (1998) and 151,000 Btu/gal

Footnotes:
(1) Based on average of stack tests from last 5 years.
(2) Based on 93% of PM emissions for bagasse burning based on limited testing of a bagasse boiler.
(3) Test data not available; assumed equal to permit limit of 1.7 lb/ton wet bagasse.
(4) Based on permit limit.
(5) Based on stoichiometric calculation of sulfur content (1.5 %) and density of No. 6 fuel oil (8.22 lb/gal).
(6) Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
(7) Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
(8) Based on average emission factor from stack testing of 5 bagasse boilers in Florida (refer to appendices).
(9) Assumed as 100% of PM emissions.
(10) Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Table 3-4. Net Emissions Increase for Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	PSD Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	100.5	216.0	115.5	25	Yes
PM10	93.9	201.6	107.7	15	Yes
Sulfur Dioxide	19.9	168.0	148.1	40	Yes
Nitrogen Oxides	70.6	362.3	291.7	40	Yes
Carbon Monoxide	5,285.1	9,360.0	4,074.9	100	Yes
Volatile Organic Compound	207.8	720.0	512.2	40	Yes
Sulfuric Acid Mist	1.2	8.8	7.6	7	Yes
Lead	0.37	0.64	0.27	0.6	No
Mercury	0.007	0.055	0.048	0.1	No
Beryllium	1.46E-06	6.94E-06	5.47E-06	4.00E-04	No

Table 1-1. Estimated Emissions for the Proposed Project (revised August 20, 1999)

Pollutant	Boiler No. 4 Baseline Emissions (TPY)	Boiler No. 4 Future Maximum Emissions (TPY)	Sugar Refinery Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PDS Significant Emission Rate (TPY)
PM	100.5	216.0	24.0	139.5	25
PM_{10}	93.9	201.6	24.0	131.7	15
SO_2	19.9	168.0	30.7	178.8	40
NO_x	70.6	362.3	8.8	300.5	40
CO	5285.1	9,360.0	7.8	4,082.7	100
VOC	207.8	720.0	20.1	532.3	40
Sulfuric Acid Mist	1.2	8.8	0	7.6	7
Lead	0.37	0.64	0	0.27	0.6
Mercury	0.007	0.055	0	0.048	0.1
Beryllium	0.0000015	0.0000069	0	0.0000055	0.0004

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External combustion boilers; Industrial; Residual oil; Grade 6 oil**	
2. Source Classification Code (SCC): **1-02-004-01**	
3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.5**	5. Maximum Annual Rate: **500**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.7**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **150**	
10. Segment Comment (limit to 200 characters): **Max hourly and annual rates based on permit specific conditions.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **SO2**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **646.6** lb/hour **168.0** tons/year
4. Synthetically Limited? [**X**] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr
6. Emission Factor: **2.5 %S** Reference: **Fuel Sulfur Limit**
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [**X**] 5
8. Calculation of Emissions (limit to 600 characters): **See Tables 2-1 and 2-2. Note that the maximum hourly SO_2 emission reflect the assumption of 2.5-percent sulfur fuel oil burned from the plant common fuel oil tank.**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Max hourly emissions representative of combined carbonaceous fuel and fuel oil firing.**

Emissions Unit Information Section 1 **of** 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 2.5 % Sulfur Oil	
4. Equivalent Allowable Emissions: 645.6 lb/hour	168.0 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 6 or 6C	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Applies to total combined carbonaceous fuel and fuel oil firing.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.1 lb/MMBtu	
4. Equivalent Allowable Emissions: 63.3 lb/hour	140.3 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 6 or 6C	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Applies to carbonaceous fuel firing only.	

Emissions Unit Information Section 1 **of** 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 2.5 %S fuel oil	
4. Equivalent Allowable Emissions: 615 lb/hour	27.8 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Analysis	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on max heat input of 225 MMBtu/hr from fuel oil firing and assumes no removal in wet scrubber. Annual emission based on 500,000 gal/yr.	

B.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: VOC
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **316.5** lb/hour **720.0** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr
6. Emission Factor: **0.5** lb/MMBtu Reference: **Proposed Limit**
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5
8. Calculation of Emissions (limit to 600 characters): **See Tables 2-1 and 2-2**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Max emissions representative of carbonaceous fuel firing. Annual emissions based on heat input rate of 2,880,000 MMBtu/yr.**

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER				
2. Future Effective Date of Allowable Emissions:				
3. Requested Allowable Emissions and Units: 0.5 lb/MMBtu				
4. Equivalent Allowable Emissions:	316.5	lb/hour	720.0	tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):				

B.

1. Basis for Allowable Emissions Code:				
2. Future Effective Date of Allowable Emissions:				
3. Requested Allowable Emissions and Units:				
4. Equivalent Allowable Emissions:		lb/hour		tons/year
5. Method of Compliance (limit to 60 characters):				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):				

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Murray J. Burnson, VP
US Sugar Corp
111 Ponce DeLeon Ave
Clewiston, Fl 33440

4a. Article Number
Z 333 618 126

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
8.20.98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Sign
X

PS For ceipt

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

Z 333 618 126

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Burnson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 8-18-99 051003-009-AC PSD-F1-272	

PS Form 3800, April 1995

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

August 18, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information No. 2
DEP File No. 051003-009-AC (PSD-FL-272)
Increased Operation of Boiler No. 4 and Refinery Expansion

Dear Mr. Brinson:

On August 4, 1999, the Department received additional information for the above referenced project in response to our request. Several of these questions require further clarification and the application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form. The original numbers identify the following remaining questions.

4. The initial response did not address the issue of costs. As previously requested, please provide a cost effectiveness analysis for fuel oil containing lower sulfur contents, such as 0.05%, 0.5%, 1.0%, and 1.5% sulfur by weight, or some similar breakdown. For example, No. 4 fuel oil, identified as a light residual oil, may contain as little as 0.4% sulfur by weight. If the use of a very low sulfur fuel would require replacement of the burners, combustion air system, fuel storage, or controls, include this in the cost estimate for that type of fuel. In addition, evaluate potential reductions in sulfur dioxide emissions that may be obtained by lowering the overall sulfur content of fuel oil fired in the common fuel storage system shared with the other bagasse boilers. This alternative should be ranked in order of effectiveness with other methods providing a top-down control analysis. The purpose of this question is to accurately define the "best available control technology" for reducing the proposed increase in SO2 emissions of nearly 350 tons per year.

5. The initial response indicates that there are no methods of regularly verifying SO2 removal efficiencies, but does identify that wet scrubbing in an alkaline environment may provide substantial SO2 removal. Please explain why maintaining the scrubber water at a given pH could not be an effective method of further controlling SO2 emissions by the same mechanism. If this method is technically feasible, it should be included in the top-down analysis previously requested. Please evaluate this option as a potential control option that may be available for reducing the proposed increase in SO2 emissions of nearly 350 tons per year.

10. The initial response verifies that the permittee measures and records the pH of the scrubber water discharge, but does not know why. Again, what is the typical pH range? Please speculate as to how the pH of the scrubber water could be adequately monitored and maintained to ensure the assumed

SO2 removal efficiencies? Have SO2 stack tests been performed for bagasse boilers to quantify the potential control effectiveness of maintaining or perhaps enhancing an alkaline scrubbing media? What were the results of these tests? Does stack test information for this boiler exist suggesting a lower, achievable BACT emissions limit that could be verified by testing? As requested above, please evaluate this option as a potential control option that may be available for reducing the proposed increase in SO2 emissions of nearly 350 tons per year.

12. For the existing boiler wet scrubber, identify the optimum range of operation for the scrubber pressure drop in inches of water. This range should reflect the minimum pressure differential above which would be an indicator of effective operation as well as the maximum level that would indicate other problems and the need for investigation by the operator. In addition, identify the scrubber flow rate (gpm) that would correspond to the pressure drop range and aid in minimizing particulate matter emissions. These should be known parameters defined by the original equipment manufacturer and the long history of operation for this boiler. Provide a cost estimate for an automatic control system that would maintain the desired scrubber liquid level and pressure drop.

13. What is the optimum range for the exhaust gas oxygen concentration that indicates adequate excess air is being supplied to the combustion process? In other words, what is the parametric range below which would be an indicator of insufficient oxygen for complete combustion, but above which would provide no additional benefit? This should be a known parameter defined by the original equipment manufacturer and the long history of operation for this boiler (stack test data). An oxygen and/or carbon monoxide monitor could be used to as feedback to the operator in order to adjust air and fuel rates in an effort to reduce emissions. A CO monitor could provide valuable historical data on emissions and operation that could be used in developing a plan for "good combustion practices". An automatic control system could be installed to automate boiler operation. Could combinations of these options be used to update previous "good combustion practices"? Are add-on controls such as an oxidation catalyst feasible for a bagasse boiler. Please evaluate these options for the potential to lower CO and/or VOC emissions limits and reduce the proposed increases in CO emissions of nearly over 4000 tons per year and VOC emissions of nearly 2000 tons per year.

16. The initial response requested consideration of raising the limit on the fuel oil sulfur content from 0.03% to 0.05% by weight. The Department will consider this request in combination with lowering the sulfur content of the fuel oil in the common storage tank shared with the other boilers. The response also requested replacing the requirement to stack test the Granular Carbon Regeneration Furnace (GCRF) for SO2 with a requirement to document the fuel sulfur content. The Department will consider this request. Please submit a summary of the tested SO2 emissions for the GRCF.

    As part of this modification, the Department will require VOC and PM testing to verify the manufacturer's stated control efficiencies of 92% and 98%, respectively. Again, please identify critical parameters to be monitored on the GCRF, afterburner, and wet venturi scrubbing system that will minimize emissions.

21. The use of the ISC Prime model MUST be approved by the EPA before this application will be deemed complete, otherwise it may be necessary to re-model using an appropriate EPA-approved model. It is the Department's understanding that this approval may be made by the EPA Region 4 Administrator. We also understand the EPA Region 4 contact to be Stan Krivo.

22. The Department previously forwarded comments and questions from the NPS regarding the BACT determinations and has attached them to this request. Dee Morse of the National Park Service indicated that questions regarding the modeling analysis should follow next week. The Department will forward these comments and questions as soon as possible. Please provide responses to the NPS's concerns.

According to Table 1-1 in the application, the proposed modification will result in the following significant increases: 139.5 TPY of PM; 131.4 TPY of PM10; 348.2 TPY of SO2; 300.4 TPY of NOx; 4082.7 TPY of CO; and 1972.3 TPY of VOC. To date the applicant has not provided a top-down BACT analysis for each significant pollutant nor suggested any methods to substantially reduce these emissions. No evaluation of technically feasible controls or associated costs have been provided for SO2, NOx, CO, or VOC. It is imperative that the Department obtain this information in order to process your BACT determination as soon as possible.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to Cleve Holladay (meteorologist) at 850/921-8986.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Phil Barbaccia, South Florida District DEP
Mr. David Buff, P.E., Golder Associates

INTEROFFICE MEMORANDUM

Date: 11-Aug-1999 12:40pm
From: Dee_Morse
Dee_Morse@nps.gov
Dept:
Tel No:

To: jeff.koerner (jeff.koerner@dep.state.fl.us)

Subject: US Sugar PSD Application

Jeff,

Below are Don Shepherd's comments related to the BACT section of US Sugar's PSD application. As I said on the phone, John Notar still needs to look at the modeling. I think he will be able to review the modeling later this week or early next week and we can then get a letter off to the Florida DEP late next week. The letter will have Don's BACT comments and John's comments (if he has any). Thanks

US Sugar (USS) proposes to increase the permitted operating hours of it bagasse- and #6 oil-fired Boiler #4, and expand the current sugar refinery operation. USS proposes no new or additional controls to reduce the increase in emissions.

PSD Applicability

Although USS is acknowledging PSD applicability for all criteria pollutants, it has concluded that PSD is not triggered for sulfuric acid mist, even though future maximum emissions would be double the PSD significance level. USS bases this conclusion on a comparison of future maximum emissions to "Baseline" emissions. Because I could not find any description of how these "Baseline" emissions were calculated, we should request clarification on this issue.

USS states that, even though there would be additional emissions of criteria pollutants from the sugar mill and bagasse handling system, they need not be considered because PSD is already triggered. However, in order to correctly assess the impacts of all PSD-applicable increases in emissions, these additional emissions must be included in the PSD analysis.

Best Available Control Technology (BACT)

Particulate Matter (PM): USS concluded that addition of an electrostatic precipitator (ESP) to the #4 boiler exhaust would be economically infeasible at a cost of $8436/ton removed. First, the threshold for acceptable costs should be defined. Because an ESP is in operation on a similar bagasse-fired boiler #7 at this mill, the cost-effectiveness of that boiler/ESP combination should be provided for use as the criterion. Second, there are several errors in the cost analysis for boiler #4 that tend to inflate costs:
The wet cyclone cost may be unnecessary if the existing impingement scrubber is retained for boiler #4.
It is not appropriate to include Working Capital costs.
The estimate that an operator will be required for eight hours per day for the ESP exceeds the three hours per day recommended by the OAQPS Control Cost Manual.
The interest rate used for the Capital Recovery Factor should be 7% instead of

10% according to the OAQPS Control Cost Manual.
Equipment life should be 20 years instead of 10 years according to the OAQPS Control Cost Manual.
If costs for the #4 boiler ESP were scaled from the #7 boiler ESP, all costs and scaling methods should be presented. Furthermore, the efficiency of the boiler #7 ESP should be provided; the efficiency for the boiler #4 ESP is only 75% and seems too low.

Nitrogen Oxides (NOx): USS concluded that the current "good combustion practices" represent BACT because they achieve an average emission rate of 0.08 lb/mmBtu. While we agree that this represents BACT, we also believe that this level of control should be reflected in the revised permit. A permit limit of 0.10 lb/mmBtu would allow for a 25% increase above average emissions.

Sulfur Dioxide (SO2): USS proposes to maintain the maximum sulfur content of the backup fuel oil at 2.5 % maximum, and to replace any oil burned with 1.5% sulfur oil. Because #6 oil can be obtained with much lower sulfur contents, USS should justify why it should not use those lower sulfur oils.

Conclusions & Recommendations

USS should explain how it calculated "baseline emissions" in determining PSD applicability.
PM control costs are overstated and should be corrected. A PM cost threshold should be defined.
The NOx limit should be lowered to reflect actual capabilities of boiler #4.
Use of lower sulfur oil for back up should be evaluated.

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3. Article Addressed to:

Mr. Murray T. Brinson, Vice Pres.
United States Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

4a. Article Number
P 265 657 758

4b. Service Type
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PS Form **3800**, April 1995

Kim

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 22, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information
DEP File No. 051003-009-AC (PSD-FL-272)
Increased Operation of Boiler No. 4 and Refinery Expansion

Dear Mr. Brinson:

On June 25, 1999, the Department received your application and complete fee for a PSD air construction permit for the above referenced project. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. As a result of the proposed changes, will any other processes or emissions units at this facility increase process rates or production rates? For example, will any of the combustion sources (other than Boiler No. 4) or material handling sources (other than the identified refinery units) increase operation as a result of increasing the operation of Boiler No. 4 or expanding the refinery?
2. Please verify the following maximum production capacities for the refinery operations:
   - 2000 ton/day sugar packaging (720,000 ton/year)
   - 2200 ton/day bulk sugar loadout (803,000 ton/year)
3. Provide the oil firing rates for Boilers 1 through 4 collectively for the 1997 and 1998 calendar years. What was the average fuel oil sulfur content for these years? For the 1999 season, when was fuel oil in the common storage tank replaced with fuel oil containing no more than 1.5% sulfur by weight, equivalent to the amount fired in Boiler No. 4?
4. For fossil fuel-fired steam generating units, Rule 62-296.406, F.A.C. requires a state BACT determination for SO_2 and PM. As a result, the Department has issued many state permits establishing very low sulfur fuels (< 0.05% sulfur by weight) as BACT for these pollutants. Also, recent BACT determinations for combustion turbines establish very low sulfur distillate oil (< 0.05% sulfur by weight) as BACT for SAM, SO_2, and PM. Provide

supporting information documenting reasons why a similar fuel cannot be fired in Boiler No. 4. Also, provide a cost effectiveness analysis for fuel oil containing 0.05%, 0.5%, 1.0%, and 1.5% sulfur by weight, or some similar breakdown.

5. Table 2-1, Note 3 indicates 40% SO_2 removal efficiency from the wet scrubber when burning bagasse. Table 6-3, Note 6 indicates a 75% SO_2 removal efficiency from the wet scrubber when burning bagasse based on industry test data. SO_2 removal from the wet scrubber is not demonstrated for bagasse boilers. Please revise these tables to show no SO_2 removal and update any modeling for SO_2 based on assumed SO_2 removal by the wet scrubbers, if necessary.

6. Table 2-1, Note 10 indicates the SO_2 maximum hourly emissions rate was based on firing oil with a sulfur content of 0.7% by weight. Why was this sulfur content used? The current permit limit is 1.5% sulfur, the proposed BACT limit is 1.5% sulfur, and oil fired in this boiler currently is supplied from a common tank containing oil between 1.5% and 2.5% sulfur by weight. Please explain and revise as necessary.

7. Table 2-1 provides maximum 6-hour average emission rates. Why were these included and were these emissions rates used for modeling purposes?

8. Table 6-4 indicates 93% of the PM is PM_{10}. Please provide supporting documentation to verify this estimate.

9. Other than the covered truck/rail loadout area, are there any other sources of fugitive emissions? Are all conveyors enclosed, including bagasse handling?

10. The current permit and O&M manual require the operators to test and record the pH of the scrubber water discharge at least twice per shift. What is the purpose for measuring and recording this parameter? What is the typical pH range? Does the facility add alkaline material to adjust the pH? Could the pH of the scrubber water be adequately maintained to control SO_2 emissions? Have SO_2 stack tests been performed for bagasse boilers to quantify the potential control effectiveness of maintaining an alkaline scrubbing media? What would be an acceptable pH range?

11. Is the volumetric flow rate for Boiler No. 4 controlled by a variable speed fan to continuously adjust and maintain the scrubber water level for maximum particulate matter control by the Joy Turbolaire wet scrubber?

12. Based on the long history of particulate matter stack tests for Boiler No. 4 and other similar bagasse boilers, what is the optimum range of operation for the scrubber pressure drop in inches of water? In other words, what would be the minimum pressure differential above which would be an indicator of effective operation, but below which may indicate a problem? What would be the maximum pressure differential below which would be an indicator of effective operation, but above which may indicate a problem?

13. What is the optimum range for the exhaust gas oxygen concentration that indicates adequate excess air is being supplied to the combustion process? In other words, what is the parametric range below which would be an indicator of insufficient oxygen for complete combustion, but above which would provide no additional benefit?

14. Table 1-1 on page 1-3 of the PSD Analysis indicates baseline emissions for Boiler No. 4. What were the baseline emissions for the existing sugar refinery?

15. Provide Table 3-1 and 3-2 for the June 14, 1999 permit modification (051-0003-008-AC) for the refinery operations. These tables were missing from information provided in the application.

16. Attachment UC-EU2-L3 provides control equipment parameters for the refinery operations. This attachment indicates a VOC destruction efficiency of 92% and a particulate matter control efficiency of 98% for emissions from the Granular Carbon Regeneration Furnace (GCRF) controlled with an afterburner and wet venturi scrubbing system. Please submit the most recent destruction/control efficiency tests conducted for this unit. What parameters are monitored to ensure the highest level of control?

17. Page 6-8 indicates that part-year operation of Boiler No. 4 was input to the air modeling analysis. In other words, some months had maximum emissions and some months had zero emissions. The application requests the ability to operate at maximum capacity at any time during the year with a cap on total heat input (steam production). Shouldn't the maximum capacity for every month be used for purposes of modeling? Please re-model, if necessary.

18. Page 6-9 indicates that "actual maximum" 1-hour CO emissions rates were used to model Boiler Nos. 1,2, and 3. Were "actual maximum" values based on individual test data? Were these values used because there are no permitted CO standards for these boilers?

19. In Louisiana and Hawaii, what control technologies are currently being used to control emissions of CO, NOx, PM, SO_2, and VOC from bagasse boilers? Sugar is also produced from sugar beets. Are any of the equipment or controls used in this industry applicable to the sugarcane industry?

20. Submit diskettes containing all of the air quality impact analysis modeling input/output files.

21. The modeling was performed with ISC Prime, which has not been approved by the EPA. Please submit the supporting documentation as previously requested from Golder Associates by the Department (attached). The use of the ISC Prime model MUST be approved by the EPA in writing before this project will be deemed complete, otherwise it may be necessary to re-model using the EPA-approved model.

22. Dee Morse of the National Park Service indicated that they would be providing comments and questions about the first week of August. The Department will forward these comments and questions as soon as possible. Please provide additional information and responses to the NPS's concerns.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions,

please call me at 850/414-7268. Matters regarding modeling issues should be directed to Cleve Holladay (meteorologist) at 850/921-8986.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Phil Barbaccia, South Florida District DEP
Mr. David Buff, P.E., Golder Associates

BEST AVAILABLE COPY

Lotus cc:Mail for Brenda Johnson

Author: Brenda Johnson at REGION4
Date: 05/18/99 02:53 PM
Priority: Normal
TO: cathy_wilson@ncair.net at IN
CC: Kay Prince, Randy Terry, Stanley Krivo
BCC: Brenda Johnson
Subject: ISC-Prime

Cathy:

The following questions are being sent in response to your telephone call on what is required to use the ISC-PRIME model for modeling demonstrations. First of all, ISC-PRIME is a not an EPA guideline model but has been under review by EPA. For regulatory purposes, the ISC3 model should be used. Case-by-case consideration and approval of non-guideline models are possible with the appropriate justification per section 3.2 of 40 CFR Part 51, Appendix W: Guideline on Air Quality Models. Any approval for ISC-PRIME, unless it became an EPA model, would be on a case-by-case basis and would not imply approval for use by other sources. Specifically, some questions/items that must be addressed for a case-by-case approval of ISC-PRIME include:

1. Why does ISC-PRIME offer a better theoretical simulation of the problem?

2. Based on the available performance evaluation data for ISC-PRIME, why would ISC-PRIME be expected to perform better than ISC3 for this application. To do this latter evaluation, the source/state should identify the evaluation data base(s) that is (are) similar to the situation for the proposed source. To assess similarity, the building/source geometry and the stack effluent characteristics should be compared for the evaluation data base and the proposed source. This could include a comparison of the stack height to building height ratios, and a comparison of the momentum and buoyancy fluxes.

3. Discuss the model evaluation of the ISC-PRIME model.

If this demonstration will be submitted to EPA as a SIP revision, we would prefer that a modeling protocol be submitted first. Approval of a non-guideline model should be approved prior to it use. Please let me know if I can be of further assistance. Have a great day....
Brenda Johnson

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 2, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Re: U.S. Sugar Corporation
0510003-009-AC, PSD-FL-272

Dear Mr. Bunyak:

Please disregard the previous cover letter for the above mentioned project and replace it with this one. We apologize for any inconvenience.

The applicant plans to increase operation of Boiler No. 4 and the sugar refinery.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at (850)922-6979. If you have any questions, please contact Jeff Koerner at (850)414-7268.

Sincerely,

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 2, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: U.S.Sugar Corporation
0510003-009-AC, PSD-FL-272

Dear Mr. Worley:

Please disregard the previous cover letter for the above mentioned project and replace it with this one. We apologize for any inconvenience.

The applicant plans to increase operation of Boiler No. 4 and the sugar refinery.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at 850/922-6979. If you have any questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

Golder Associates Inc.

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

June 24, 1999

993-7515

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

RECEIVED
JUN 25 1999
BUREAU OF
AIR REGULATION

Attention: Clair Fancy, Chief Bureau of Air Quality

RE: U.S. Sugar Corporation, Clewiston, Florida
PSD Permit Application

0510003-009-AC
PSD-FL-272

Dear Mr. Fancy:

On behalf of United States Sugar Corporation, (US Sugar), Golder Associates Inc. (Golder) is submitting to the Florida Department of Environmental Protection (FDEP) a Prevention of Significant Deterioration (PSD) permit application. This application is presented in support of US Sugar's intent to modify operations at their facility located in Clewiston, Florida. Specifically, US Sugar is proposing to increase the annual hours of operation and steam production for existing Boiler No. 4. US Sugar is also proposing to modify their existing sugar refinery by increasing the annual hours of operation for some units, installing three new sugar conditioning silos, and installing several powdered sugar/starch bins.

The existing sugar refinery was construction under Permit No. 0510003-004-AC. New Source Review under PSD regulations was not required for construction of the sugar refinery because potential emissions were below significant emission rates. However, the proposed modifications to the sugar refinery described in this application will result in potential emissions of particulate matter (PM) for the entire sugar refinery above the PM significant emission rate of 15 TPY. As such, PSD review for the refinery was triggered and it was considered a new facility for the purposes of this application.

Enclosed, we have provided four copies of the permit application and a check for the application fee of $7,500. Your attention to this matter is greatly appreciated as the requested modifications to the operation of Boiler No. 4 is critical to US Sugar's

upcoming crop season. If you have any questions concerning this application, please call David Buff or myself from Golder at (352) 336-5600 or Don Griffin from US Sugar at (941) 902-2711.

Sincerely,

GOLDER ASSOCIATES INC.

Scott A. McCann, P.E.
Senior Engineer

SAM/arz

Enclosures

cc: D. Buff, Golder
D. Griffin, US Sugar
B. Wehrum, Latham & Watkins

G:\DATA\DP\PROJECTS\99\9937\9937515Y\F2\WP\#01-LTR.doc

CC: J. Koerner, BAR
EPA
NPS
SD
C. Holladay, BAR
File

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	TOTALS:	7,500.00	0.00	7,500.00

United States Sugar Corporation

United States Sugar Corporation

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[redacted]

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

IN REPLY REFER TO:

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BUREAU OF AIR REGULATION

August 23, 1999

N3615 (2350)

A.A. Linero, P.E., Administrator
Department for Environmental Protection
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

We have reviewed U.S. Sugar Corporation's (USS) Prevention of Significant Deterioration (PSD) permit application for the increase in permitted operating hours for boiler #4 and expansion of the current sugar refining operation at their Clewiston, Florida, facility. The facility is located approximately 102 kilometers north of Everglades National Park (NP), a Class I air quality area administered by the National Park Service (NPS). Proposed changes to the USS facility will cause emissions of volatile organic compounds to increase by 1,972 tons per year (TPY), sulfur dioxide to increase by 348 TPY, particulate matter to increase by 139 TPY, and nitrogen oxide emissions to increase by 300 TPY.

Based on our review of the permit application, we do not anticipate that the proposed project will have a significant impact on sensitive resources at the park. However, we do have the following comments regarding the PSD application.

PSD Applicability

Although USS is acknowledging PSD applicability for the above listed criteria pollutants, it has concluded that PSD is not triggered for sulfuric acid mist, even though future maximum emissions would be double the PSD significance level. USS bases this conclusion on a comparison of future maximum emissions to "baseline emissions." USS states that, even though there would be additional emissions of criteria pollutants from the sugar mill and bagasse handling system, they need not be considered because PSD is already triggered. However, in order to assess the impacts of all PSD-applicable increases in emissions, these additional emissions must be included in the PSD analysis. USS should explain how it calculated "baseline emissions" in determining PSD applicability, and compare the current actual emissions to future potential emissions.

Best Available Control Technology (BACT)

USS proposes to increase the permitted operating hours of its bagasse and oil-fired boiler #4, and expand the current sugar refinery operation. USS proposes no new or additional controls to reduce the increases in emissions.

Particulate Matter: USS concluded that adding an electrostatic precipitator (ESP) to the #4 boiler exhaust would be economically infeasible at a cost of $8436/ton removed. First, the threshold for acceptable costs should be defined. Because an ESP is in operation on a similar bagasse-fired boiler #7 at this mill, the cost-effectiveness of that boiler/ESP combination should be provided for use as the criterion. Second, there are several errors in the cost analysis for boiler #4 that tend to inflate costs:

- The wet cyclone cost may be unnecessary if the existing impingement scrubber is retained for boiler #4.
- It is not appropriate to include Working Capital costs.
- The estimate that an operator will be required for eight hours per day for the ESP exceeds the three hours per day recommended by the OAQPS Control Cost Manual.
- The interest rate used for the Capital Recovery Factor should be 7% instead of 10% according to the OAQPS Control Cost Manual.
- Equipment life should be 20 years instead of 10 years according to the OAQPS Control Cost Manual.

If costs for the #4 boiler ESP were scaled from the #7 boiler ESP, all costs and scaling methods should be presented. Furthermore, the efficiency of the boiler #7 ESP should be provided; the efficiency for the boiler #4 ESP is only 75% and seems too low. In conclusion, PM control costs are overstated and should be corrected, and a PM cost threshold should be defined.

Nitrogen Oxides: USS concluded that the current "good combustion practices" represent BACT because they achieve an average emission rate of 0.08 lb/mmBtu. While we agree that this represents BACT, we also believe that this level of control should be reflected in the revised permit. A permit limit of 0.10 lb/mm Btu would allow for a 25% increase above average emissions. The NO_x limit should be lowered to reflect actual capabilities of boiler #4.

Sulfur Dioxide: USS proposes to maintain the maximum sulfur content of the backup fuel oil at 2.5 % maximum, and to replace any oil burned with 1.5% sulfur oil. Because #6 oil can be obtained with much lower sulfur content, USS should justify why it should not use those lower sulfur oils. Use of lower sulfur oil for back up should be evaluated.

Air Quality Analysis

The review of the air quality analysis indicates that impacts from the major modification to boiler #4 would be below the EPA's proposed Class I increment significant levels for particulate matter (PM_{10}), nitrogen dioxide (NO_2), and the sulfur dioxide (SO_2) annual

average. The analysis indicated that the modification would significantly impact the Class I increment at Everglades NP for the 3-hour and 24-hour averaging periods for SO_2. Therefore, U.S. Sugar performed a cumulative Class I increment analysis, including 20 increment-consuming sources, to access the impact to the short term averaging periods. This analysis indicated a cumulative impact of 3.0 $\mu g/m^3$, and 18.0 $\mu g/m^3$ for the 24-hour and 3-hour averaging periods, respectively. These levels are below the respective Class I increments of 5 and 25 $\mu g/m^3$

The increment and acid deposition analyses were performed with EPA's ISCST3 model. In December 1998, the EPA released the latest guidance for modeling impacts to Class I areas beyond 50 kilometers from the source. The ISCST3 model is no longer the recommended model for long-range transport analyses. Future PSD applications which require long-range transport analyses to assess impacts to increments and air quality related values, for Class I areas, should follow the latest guidance in the EPA document *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts EPA-454/R-98-019 December 1998*. The IWAQM Phase 2 guidance suggests that PSD applicants use the CALPUFF model for both a screening level analysis and refined analysis.

USS did apply the CALPUFF model in the screening mode to assess impact to regional haze at Everglades NP. The analysis was performed correctly, and indicates an impact of a 3% change in extinction, which is below the NPS threshold value of a 5% change in extinction.

In the future, we request that Florida Department for Environmental Protection inform applicants to contact the NPS Air Resources Division or the U.S. Fish and Wildlife Services Air Quality Branch before starting future modeling analyses. We will advise applicants of the significant change in dispersion modeling methodology and techniques in IWAQM Phase 2.

Thank you for involving us in the review of the PSD permit application for the USS facility. Please do not hesitate to contact Mr. Dee Morse of my staff at (303) 969-2817 regarding future air quality matters involving the NPS.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch

CC: EPA
SD
D. Buff, Golder
J. Koerner, BAR

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Mr. Murray T. Brinson, V.P.
United States Sugar Corp.
111 Ponce De Leon Ave.
Clewiston, FL 33440

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C. Signature

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PS Form **3800**, April 1995

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 21, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Additional Information Request No. 2
DEP File No. 0510003-010-AC (PSD-FL-272A)
Revised ISC Prime Modeling Scenario

Dear Mr. Brinson:

On May 23, 2000, the Department received additional information requested on February 4, 2000. The Department reviewed this information and has some additional questions regarding the revised modeling scenario. The application remains incomplete. In order to continue processing your application, the Department will need the additional information attached to this letter. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form. *Prior to revising the modeling analysis, the Department would like to meet with your consultant to establish acceptable scenarios to prevent further delays.*

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If you have any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to the project meteorologist, Cleve Holladay, at 850/921-8986.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. David Buff, P.E., Golder Associates
Mr. David Knowles, SD
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

1. Response to FDEP No. 1 and EPA No. 1: The response indicates that Boiler Nos. 1-3 are not currently restricted on annual operating hours or to only operating during the crop season. However, it is the recent startup of the refinery that would actually allow these units to operate during the traditional off-season. In addition, excess sugar cane and bagasse will be brought in from U.S. Sugar's Bryant mill. Please explain why operation of Boiler Nos. 1-3 during the off-season would not be considered a change in the method of operation and therefore a modification.

   Also, please define "crop season" dates for the PSD baseline cases as well as for the proposed project. There appear to be inconsistencies between the various modeling runs. For example, the off-season SO_2 PSD Class I increment screening runs have monthly activity factors of "1" for the period of May to October while the corresponding refined runs have monthly activity factors of "1" for the period of April to October. The analyses should be consistent. In addition, they should also be conservative. In evaluating the increment consumption of the proposed project, partial operation during a month should be input as full operation for that month. In the example above, the refined runs with monthly activities of "1" for the period of April to October would be correct if there is any proposed off-season operation for April.

2. Response to FDEP No. 2 and EPA No. 2: Comments for the Section 6.0 tables are provided below.

3. Response to FDEP No. 3 and EPA No. 4: No comment.

4. Response to FDEP No. 4 and EPA No. 5: Comments for the Section 6.0 tables are provided below.

5. Response to FDEP No. 5: No comment.

6. Response to EPA No. 3: Comments regarding CO emissions are provided below.

7. Crop Season Operational Restrictions: Please provide information that supports the "worst-case scenarios" presented for Boiler Nos. 1-4. The Department is not yet convinced because the restrictions on fuel oil involve four different boilers, different heat input rates, different fuel consumption rates for each boiler, and different fuel sulfur limits. Please provide the maximum 1-hour fuel consumption rate for each boiler based on design specifications. Additional comments are provided below.

8. Off-Season Operational Restrictions (1-hr, 3-hr, and 8-hr Operation): The Department is not convinced that the worst case scenario is presented for limiting total steam production from Boiler Nos. 1-4 and 7 to 1,062,800 lb/hr. These units have different stack heights, diameters, heat inputs, velocities, fuel oil consumption rates, and steam enthalpies. Please provide information that supports the "worst-case scenarios" presented or simplify the restrictions. The Department is not yet convinced because the restrictions on fuel oil involve four different boilers, different heat input rates, different fuel consumption rates for each boiler, and different fuel sulfur limits. Also, please revise the heat input from bagasse to reflect the remaining heat input after subtracting the heat input from oil firing. In other words, it is inappropriate to consider an 80% thermal efficiency from oil firing for these units. Historically, the Department has made concessions to limit and monitor the steam production as a surrogate for fuel consumption. Otherwise, the Department is considering a requirement to install weigh scales and limit bagasse consumption to provide reasonable assurance. Additional comments are provided below.

9. Off-Season Operational Restrictions (24-hr Operation): The Department offers the same comments as no. 8 above. It is inappropriate to limit fuel oil firing based on steam production. Again, the Department is not convinced that the worst case scenario is presented for limiting total steam production or fuel oil consumption for the various combinations presented. Please provide information that supports the "worst-case scenarios" presented or simplify the restrictions. What are the process steam needs during the off-season? What combinations of boilers could be used to meet these needs? If the steam needs can be met with only a few boilers, the Department believes the modeling can be greatly simplified. Additional comments are provided below.

10. Table 2-1, Short-Term Emissions for Boiler No. 4: Footnote (a) indicates 55% thermal efficiency for bagasse firing and 80% thermal efficiency for oil firing. The thermal efficiency for bagasse firing is fairly well established. The Department does not believe this assumption to be accurate for a boiler designed to fire primarily bagasse with supplemental oil firing. Please revise and base solely on the maximum oil-firing rate allowed by permit with the remaining heat input coming from bagasse.

11. Table 2-2, Future Maximum Annual Emissions for Boiler No. 4: Although the industry has performed some particulate tests to establish the fraction of PM_{10} emissions, no separate limits have been imposed for PM_{10}. In addition, the Department is not aware of any recent PM_{10} tests conducted for this industry. Please revise the modeling based on the assumption that all of the PM emissions are PM_{10}.

12. Table 2-4, Emissions from Granular Carbon Regenerative Furnace (GCRF): The SO_2 emission rate should be based on 0.05% not 0.03% sulfur by weight because the permit was revised. A review of the file indicates that an SO_2 limit and testing was required for the GCRF because the decolorization process may result in additional SO_2 emissions, which would be controlled by the wet scrubber. However, the current application suggests that the GCRF will only emit SO_2 as the result of fuel combustion. Please verify that the sugar refining process will not result in additional SO_2 emissions. If it does, please quantify. Also, please provide a summary of the SO_2 emissions from the GCRF for tests required in construction permit modification no. 0510003-004-AC.

13. Table 2-7, Stack Parameters for Existing and Modified Boiler No. 4: This table clearly indicates that increased steam production for Boiler No. 4 will result in higher volumetric flow rates and exit velocities. Conversely, lower steam production rates will result in lower volumetric flow rates and exit velocities. Please revise the modeling analysis to account for the lower flow rates and velocities whenever a reduced steam production or heat input is requested (for example, a reduced heat input based on a 24-hour average).

14. Table 3-4, Net Emissions increase for Boiler No. 4: Please confirm that this table represents the last permitting action (PSD-FL-272) for Boiler No. 4 and not the current request. The current request should result in no increases in emissions from Boiler No. 4.

15. Table 6-2, Summary of Stack Parameters: This table omits Boiler Nos. 5 and 6 from any consideration in the modeling analysis. A review of the operational history indicates no use during the last crop season. In addition, the emissions reductions were used as net decreases to avoid a BACT determination for at least CO emissions for the PSD permit for Boiler No. 7. The Department will remove the authority to operate these units, even for standby purposes.

16. Table 6-3, SO_2 Emissions – Future Crop Season

    a. The SO_2 emission rate for firing bagasse in Boiler No. 4 should be based on the revised permit limit of 0.06 lb/mmBTU not 0.10 lb/mmBTU. This occurs in both the 3-hour and 24-hour cases. Please revise the SO_2 emission rate for Boiler No. 4 using an emissions rate of 0.06 lb SO_2/mmBTU as the "maximum" emissions.

    b. Note (b) indicates that 75% reduction was *assumed* for bagasse firing from Boiler Nos. 1-3. The modeling analysis indicates that SO_2 is very close to the acceptable PSD increments. Therefore, it is inappropriate to assume such a large reduction. Please revise the analysis to assume no reductions Otherwise, the Department will establish appropriate permit limits and stack testing to ensure that the reduced emission levels are routinely achieved.

    c. Note (c) indicates that the steam rates for Boiler Nos. 1-3 are based on the 24-hour average steam rates. What does U.S. Sugar believe the maximum 1-hour steam rates to be? See also the Department's Table A-1 and corresponding questions.

d. Both the 3-hour and 24-hour cases include the current permit restrictions for fuel oil firing. This is inappropriate because Boiler No. 4 now has a separate fuel tank and fires oil with a lower sulfur content. Because this project includes stack height increases and a unique air dispersion model to satisfy the air quality impacts for SO_2, it is important to ensure that a lower emission rate for a unit with a shorter stack and cooler exhaust temperature would not result in a higher ambient impact. Please revise the modeling analysis accordingly and provide supporting information to indicates how the "worst case" was determined. Otherwise, model each scenario offered for consideration.

17. Table 6-4a, PM_{10} and CO Emissions – Future Crop Season

a. For Boiler Nos. 1-4, please revise and base the maximum 24-hour case on PM_{10} equal to 100% of PM emissions.

b. The emission rates for Boiler Nos. 1-3 were based on actual test data. However, the table reflects two different emission rates for these boilers, apparently based on the averaging period. Please revise the data for the maximum 8-hour case to reflect the emission rates used for the maximum 1-hour case. This is similar to using the maximum permitted emission rates for Boiler Nos. 4 and 7.

18. Table 6-4b, Maximum SO2 Emissions – Future Off-Season Operation

a. Footnotes (a) and (b) indicate 55% thermal efficiency for bagasse firing and 80% thermal efficiency for oil firing. Although the thermal efficiency for bagasse firing is fairly well established, the Department does not believes the assumption for oil firing to be accurate nor verifiable for a boiler designed to fire primarily bagasse with supplemental oil firing. Please revise and base solely on the maximum oil-firing rate allowed by permit with the residual heat input made coming from bagasse. In other words, the heat input from oil firing plus the heat input from bagasse firing will add up to the maximum design heat input rate – not a lower heat input rate.

b. Note (b) indicates that 75% reduction was *assumed* for bagasse firing from Boiler Nos. 1-3. The modeling analysis indicates that SO_2 is very close to the acceptable PSD increments. Therefore, it is inappropriate to assume such a large reduction. Please revise the analysis to assume no reductions Otherwise, the Department will establish appropriate permit limits and stack testing to ensure that the reduced emission levels are routinely achieved.

c. Note (d) indicates that the steam rates for Boiler Nos. 1-3 are based on the 24-hour average steam rates. What does U.S. Sugar believe the maximum 1-hour steam rates to be? See also the Department's Table A-1 and corresponding questions.

d. Both the 3-hour and 24-hour cases include new permit restrictions for fuel oil firing and steam rates for Boiler Nos. 1-4 and 7. The requested limits may not be adequate to determine ensure maximum emissions. As shown in this table, there are three different steam enthalpies for the five boilers and as well as three different fuel sulfur contents. Because this project includes stack height increases and a unique air dispersion model to satisfy the air quality impacts for SO_2, it is important to ensure that a lower emission rate for a unit with a shorter stack and cooler exhaust temperature would not result in a higher ambient impact. Please simplify the restrictions on the boilers to a manageable scenario, revise the modeling analysis accordingly, and provide supporting information to indicate how the "worst case" was determined. Otherwise, model each alternate scenario offered for consideration.

19. Table 6-4c, Maximum PM_{10} Emissions – Off-Season Operation

a. See Department comment 9a above.

b. U.S. Sugar requests a maximum 24-hour steam rate of 744,000 lb/hour for Boiler Nos. 1-4 and 7. Please provide supporting information that indicates the scenario provided represents the worst case.

c. See Department comment 2 above.

20. Table 6-4d, Maximum CO Emissions – Off-Season Operation

a. See Department comment 9a above.

b. Note (c) indicates that the emission rates for Boiler Nos. 1-3 were based on actual test data. However, the table reflects two different emission rates for these boilers, apparently based on the averaging period. Please revise the data for the maximum 8-hour case to reflect the emission rates used for the maximum 1-hour case. This is similar to using the maximum permitted emission rates for Boiler Nos. 4 and 7.

c. Note (d) indicates that the steam rates for Boiler Nos. 1-3 are based on the 24-hour average steam rates. What does U.S. Sugar believe the maximum 1-hour steam rates to be? See also the Department's Table A-1 and corresponding questions.

21. Tables 6-6 through 6-12, Summary of SO_2 Facilities

a. A new power plant, Lake Worth Generating, has been permitted adjacent to Lake Worth Utilities. The FPL Martin Plant has published notice on a Draft Permit for two new combustion turbines. Shouldn't the potential emissions from these two new facilities be included in the inventory?

b. Are the east and west pellet plants listed in Table 6-8 still in existence at the U.S. Sugar Clewiston facility?

22. Table 6-13, A Summary of the Building Structures: As noted in this table, several large building structures are located in the refinery and are included in the modeling analysis. The structures had not been included in any previous PSD modeling at this facility. A review of the permitting files indicates that the Bureau of Air Regulation issued a PSD permit for Boiler No. 7 in 1995. According to Golder Associates (letter dated January 16, 1997), this boiler was "designed and built with the intention of operating 8760 hours per year" to "provide steam to the new mill expansion (sugar processing system)" during the crop season as well as during the off season. The Department's South District Office issued a *minor source* permit for the refinery operations in 1996, conditioned to avoid PSD applicability. This permit was later revised to further restrict operations in an effort to maintain permitted emission levels below the Significant Emissions Rates and continue to avoid PSD applicability. As a result of these separate applications, no BACT determinations were made for the refinery units and no modeling analysis was performed that included the refinery structures. Please describe why these separate requests should not be considered "project splitting".

23. Department's Table A-1, Capacity History for Boiler Nos. 1-3 (attached): A review of the permit files indicated much lower maximum steam rates and heat input levels for Boiler Nos. 1-3, as provided by U.S. Sugar. Please see the attached summary Table A-1. For each boiler this table lists the following items:

- The maximum design steam rate (lb/hr);
- The maximum design heat input (mmBTU/hr);
- The heat input (mmBTU/hr) and firing rate (TPH) for firing only bagasse; and
- The heat inputs (mmBTU/hr) and firing rates (TPH and GPH) for firing the maximum amount of fuel oil with the remaining heat input from bagasse.

The information for "1973/1974" column is based on data provided by U.S. Sugar in previous air construction permit applications. The information for "ARMS DB" column is based on the current data available in the state's Air Resources Management Database. The information for the "proposed" column is based on data in the current proposed project. As shown, it appears that both the steam rates and heat inputs have escalated over the last 25 years. Please identify each modification made to these boilers that allowed substantial increases in the steam production rates or heat inputs including the dates, physical

changes, approvals, permit modifications, and emissions rates. Please identify what U.S. Sugar now considers to be the "maximum 1-hour" steam rates, heat inputs, and oil firing rates for each unit. Please explain why each change did not trigger a PSD modification or an NSPS modification.

24. Other Modeling Questions:

- Please include Boiler Nos. 1-3 in the off-season significant impact analysis for both the PSD Class I and Class II areas.
- Please explain the method for determining an accurate annual concentration with different emission rates for each operating season (crop season and off-season).
- Please list the radii of significant impact for all Class II significant impact analyses (both crop season and off-season) in the appropriate table.

Due to the assumptions made, the changes requested, and modeled impacts approaching the PSD increments, the Department does not yet believe the Air Quality Analysis demonstrates compliance with the Ambient Air Quality Standards or PSD increments.

TABLE A-1. CAPACITY HISTORY FOR BOILER NOS. 1-3

Parameter	Boiler No. 1			Boiler No. 2			Boiler No. 3		
	1973/1974	ARMS DB	Proposed	1973/1974	ARMS DB	Proposed	1973/1974	ARMS DB	Proposed
Steam Rate, lb/hr	175000	235000	255100	200000	235000	255100	100000	135000	167600
Design HI, mmBTU/hr	340	494	496	329	494	496	194	267	342
All Bagasse, TPH	23.6	34.3	34.4	22.8	34.5	34.4	13.5	18.5	23.8
All Bagasse, mmBTU/hr	340.0	493.2	496.0	329.0	496.8	496.0	194.0	266.4	342.0
Bagasse w/Oil, TPH	22.6	16.8	18.8	21.2	16.8	18.8	10.3	8.9	14.4
Oil, GPH	98.0	1678.0	1500.0	100.0	1680.0	1500.0	305.0	924.0	900.0
From Bagasse, mmBTU/hr	325.4	242.3	270.6	305.6	242.0	270.6	147.7	128.4	207.0
From Oil, mmBTU/hr	14.7	251.7	225.0	15.0	252.0	225.0	45.8	138.6	135.0
Total HI, mmBTU/hr	340.1	494.0	495.6	320.6	494.0	495.6	193.4	267.0	342.0

Fuel	mmBTU/Unit	Unit
Bagasse	14.4	ton
Oil	0.15	gallon

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U.S. Sugar Corp.
111 Ponce DeLeon Ave
Clewiston, Florida
33440

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PS Form **3800**, April 1995

Department of
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Jeb Bush
Governor

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

David B. Struhs
Secretary

May 26, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Notice of Receipt of Additional Information Request No. 1
DEP File No. 0510003-010-AC (PSD-FL-272A)
Revised ISC Prime Modeling Scenario

Dear Mr. Brinson:

On May 4, 2000, the Department received some of the additional information requested on February 4, 2000. We did not receive the ISC Prime modeling files until May 23, 2000. We are currently reviewing all of the information at this time and will provide any additional requests by June 21, 2000. Please be aware that the various modeling scenarios presented require numerous limitations on boiler combinations, oil firing, fuel sulfur contents, and steam production. In turn, this will require substantial amounts of frequent record keeping in order to demonstrate compliance. If you have any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to the project meteorologist, Cleve Holladay, at 850/921-8986.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. David Buff, P.E., Golder Associates
Mr. David Knowles, SD
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

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33440

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Department of Environmental Protection

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David B. Struhs
Secretary

February 7, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information No. 1 – EPA Comments
DEP File No. 0510083-010-AC (PSD-FL-272A)
Revised ISC Prime Modeling Scenario

Dear Mr. Brinson:

Review comments were received from EPA Region 4 by fax on February 4, 2000. These comments are being forwarded for your response, as discussed in the Department's request for additional information dated February 4, 2000.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to Cleve Holladay (meteorologist) at 850/921-8986.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. David Buff, P.E., Golder Associates
Mr. David Knowles, SD
Mr. John Bunyak, NPS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Review Comments on Final Air Quality Impact Analysis
US Sugar Corporation Clewiston Mill
Clewiston, Florida

Dear Mr. Linero:

Thank you for providing a review copy of the December 17, 1999, Golder Associates' letter containing the final plant configuration, fuel consumption information, air emissions data, and air quality impact assessment associated with the U.S. Sugar Corporation - Clewiston Mill. This facility was issued Final Permit No. 0510003-009-AC (PSD-FL-272) in November 1999. The purpose of Golder Associates' letter was to fulfill permit condition 7(c) which requires submittal of a final compliance demonstration for this modified facility. The following presents our air quality related comments on this letter. [Note: These comments were provided to FL DEP representative on February 2, 2000.]

1. PSD Expanding Sources - Previous communications with Golder Associates indicated current U.S. Sugar PSD expanding sources have no monthly or annual permit operational limits. They have therefore been modeled as operating for the full year. The emission rates used should be based on actual operations not permit allowables. In addition, an explanation is needed as to why Boiler 1 and 2 expansion emission rates (negative modeled emissions) are always equal to the increment consumption emission rates. This is not a normal modeling technique for PSD expanders.

2. Location of U.S. Sugar Sources - Table 10 of the December 1999, letter has new locations for the U.S. Sugar sources. These new locations were not included in the modeling provided in support of this letter.

3. CO Emission Rates - Table 7 of the letter presents CO emission rates for each of the two averaging periods of concern. Only the 1-hour rates were used in the modeling. Because the 1-hour emission rates are larger than the 8-hour values, this procedure provides appropriately conservative concentrations.

4. Stack Exit Parameters - Although the stacks for Boilers 1-3 have been raised from 165 to 182 feet, the exit temperature, velocity, and stack diameter have not changed. To ensure correct values were used in the modeling, the provided stack exit parameters need to be confirmed.

5. SO_2 Impact Analysis - The SO_2 3-hour, 24-hour and annual PSD increment analyses were not performed to 100-m receptor grid resolution. Although not correctly modeled, the basic results should not change because the resultant concentrations were all less than 15 percent of the applicable PSD increment.

   The NAAQS analysis was performed correctly. The results show the 24-hour SO_2 NAAQS concentration to be 99 percent of the standard. Because of this and the above comments on some of the model input parameters, the NAAQS SO_2 impact assessment needs to be confirmed.

Thank you again for the opportunity to comment on this final air quality impact assessment for the U.S. Sugar - Clewiston Mill. If you have any questions regarding these comments, please direct them to Stan Krivo at 404-562-9123.

Sincerely,

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

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

David B. Struhs
Secretary

February 4, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information No. 1
DEP File No. 051003-010-AC (PSD-FL-272A)
Revised ISC Prime Modeling Scenario

Dear Mr. Brinson:

On January 6, 2000, the Department received an application for the above referenced project. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Emission values used for the PSD increment expanding sources should be based on actual operations during the baseline years not permit allowables for both short-term and annual impact assessments. Please provide the basis for the negative emissions rates used for Boiler Nos. 1 and 2 in the increment analysis.
2. There is a discrepancy between the locations of U.S Sugar Clewiston Boiler Nos. 1,2,3, and 7 given in Table 10 and those used in the modeling analysis. Please provide the correct locations of the boilers.
3. Although the stacks for Boiler Nos. 1, 2, and 3 have been raised from 165 feet to 182 feet, the exit temperatures, velocities, and diameters have not changed. Please confirm that the increase in stack heights does not cause changes in the other exit parameters.
4. The SO_2 3-hour, 24-hour, and annual Class II PSD increment analyses were not performed to an equivalent 100-m receptor grid resolution. Please perform this refined modeling.
5. The Department expects to receive additional comments from EPA Region 4 shortly and will forward for your response as soon as possible.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information

within 90 days. If there are any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to Cleve Holladay (meteorologist) at 850/921-8986.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. David Buff, P.E., Golder Associates
Mr. David Knowles, SD
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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BUREAU OF AIR REGULATION

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Review Comments on Final Air Quality Impact Analysis
US Sugar Corporation Clewiston Mill
Clewiston, Florida

Dear Mr. Linero:

Thank you for providing a review copy of the December 17, 1999, Golder Associates' letter containing the final plant configuration, fuel consumption information, air emissions data, and air quality impact assessment associated with the U.S. Sugar Corporation - Clewiston Mill. This facility was issued Final Permit No. 0510003-009-AC (PSD-FL-272) in November 1999. The purpose of Golder Associates' letter was to fulfill permit condition 7(c) which requires submittal of a final compliance demonstration for this modified facility. The following presents our air quality related comments on this letter. [Note: These comments were provided to FL DEP representative on February 2, 2000.]

1. PSD Expanding Sources - Previous communications with Golder Associates indicated current U.S. Sugar PSD expanding sources have no monthly or annual permit operational limits. They have therefore been modeled as operating for the full year. The emission rates used should be based on actual operations not permit allowables. In addition, an explanation is needed as to why Boiler 1 and 2 expansion emission rates (negative modeled emissions) are always equal to the increment consumption emission rates. This is not a normal modeling technique for PSD expanders.

2. Location of U.S. Sugar Sources - Table 10 of the December 1999, letter has new locations for the U.S. Sugar sources. These new locations were not included in the modeling provided in support of this letter.

3. CO Emission Rates - Table 7 of the letter presents CO emission rates for each of the two averaging periods of concern. Only the 1-hour rates were used in the modeling. Because the 1-hour emission rates are larger than the 8-hour values, this procedure provides appropriately conservative concentrations.

4. Stack Exit Parameters - Although the stacks for Boilers 1-3 have been raised from 165 to 182 feet, the exit temperature, velocity, and stack diameter have not changed. To ensure correct values were used in the modeling, the provided stack exit parameters need to be confirmed.

5. SO_2 Impact Analysis - The SO_2 3-hour, 24-hour and annual PSD increment analyses were not performed to 100-m receptor grid resolution. Although not correctly modeled, the basic results should not change because the resultant concentrations were all less than 15 percent of the applicable PSD increment.

   The NAAQS analysis was performed correctly. The results show the 24-hour SO_2 NAAQS concentration to be 99 percent of the standard. Because of this and the above comments on some of the model input parameters, the NAAQS SO_2 impact assessment needs to be confirmed.

Thank you again for the opportunity to comment on this final air quality impact assessment for the U.S. Sugar - Clewiston Mill. If you have any questions regarding these comments, please direct them to Stan Krivo at 404-562-9123.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Koerner
C. Holladay
S. District
NPS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

FEB 0 4 2000

4 AFT-ARB

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

SUBJ: Review Comments on Final Air Quality Impact Analysis
US Sugar Corporation Clewiston Mill
Clewiston, Florida

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Sincerely,

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

Golder Associates Inc.

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

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Golder Associates

December 17, 1999

9937515

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL, 32399-2400

BUREAU OF AIR REGULATION
JAN 06 2000
RECEIVED

Attention: A. A. Linero, P.E.

RE: United States Sugar Corporation – Clewiston Mill
Air Permit No. 0510003-009-AC (PSD-FL-272)

Dear Mr. Linero: 0510003-010-AC

In accordance with Final Permit No. 0510003-009-AC (PSD-FL-272), Emission Unit No. 009, Interim Condition 7(c), United States Sugar Corporation (U.S. Sugar) is submitting an application to the Department to modify the current permit that includes the following information:

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

To satisfy Interim condition 7(c)1., U.S. Sugar is submitting Tables 1 through 4 presenting the results of an air quality modeling analysis using the ISC-PRIME dispersion model. The purpose of the air quality modeling analysis was to demonstrate compliance with AAQS

and PSD Class I and II increments for the selected combination of boiler stack heights and fuel sulfur contents. The final selected option, and this modeling analysis, is based on Boiler Nos. 1, 2, and 3 with 182-ft tall stacks (increased from the present 165 feet) and firing 2.5% sulfur No. 6 fuel oil, Boiler No. 4 with a 150-ft tall stack (existing stack height) firing 0.7% sulfur No. 6 fuel oil, and Boiler No. 7 remaining the same as currently permitted. The attached tables are identical to the Scenario 1 (R1) tables submitted in the November 17, 1999, letter response from Golder Associates to the Department, which reflect the selected option.

Both the AAQS and PSD Class II increment modeling analyses were performed in two phases and included off-site sources within the significant impact area of the U.S. Sugar facility. The first phase (screening analysis) used a coarse polar receptor grid to predict general locations of maximum annual and maximum highest, second highest short term impacts. The second phase (refined analysis) used a finer (less than 100-meter spacing) polar receptor grid centered on the location of maximum impacts predicted in the screening analysis.

The results of the AAQS screening analysis for SO_2, PM_{10} and CO are presented in Table 1. The results of the refined AAQS analysis, including an appropriate background concentration, are presented in Table 2. As shown in Table 2, the predicted SO_2, PM_{10} and CO impacts are in compliance with their respective AAQS.

The results of the PSD Class II screening analysis for SO_2 and PM_{10} are presented in Table 3. The results of the refined PSD Class II analysis are presented in Table 4. As shown in Table 4, predicted SO_2, and PM_{10} impacts are in compliance with their respective PSD Class II increments.

The results of the PSD Class I modeling analysis for SO_2 are presented in Table 5. PM_{10} impacts at the Class I area for the proposed project were below EPA's significant impact concentrations, and were therefore not evaluated further. As shown in Table 5, predicted maximum annual and maximum highest, second highest, short-term SO_2 impacts are in compliance with their respective PSD Class I increments.

To satisfy Interim Permit Conditions 7(c)2. and 7(c)3., U.S. Sugar is submitting Tables 6 through 10. Note, there is no change in the current maximum heat input rates or emission rates associated with Boiler Nos. 1, 2, 3, and 7. Summarized in Table 6 are the maximum 3-hour and 24-hour average (fuel oil and bagasse) heat input rates for the boilers for firing fuel oil and bagasse, together and separately, and corresponding maximum SO_2 emissions limits. Summarized in Table 7 are maximum 24-hour average PM_{10} emissions and maximum 1- and 8-hour average CO emissions.

Maximum annual emission rates for Boiler No. 4 are presented in Table 8. Maximum short-term emissions for Boiler No. 4 are presented in Table 9. Summarized in Table 10 are the stack parameters used in the dispersion modeling analysis presented to satisfy Interim Permit Condition 7(c)1.

To satisfy Interim Permit Condition 7(c)4., please find attached Sections I and II of the DEP Form No. 62-210.900(1) and those pages of Section III that require revision as part of the requested modifications.

To satisfy Interim Permit Condition 7(c)5., upon Department approval, U.S. Sugar will publish a Department provided Public Notice in a news paper of general circulation with a 30-day comment period.

At this time, U.S. Sugar would also like to request the following minor revisions to the current construction permit for this project:

1. Page 2, REGULATORY CLASSIFICATION, HAPs - Replace "This facility is not believed to be a major source of hazardous air pollutants", with "Based on recent data this facility is a major source of hazardous air pollutants". This is consistent with recent proposed changes to U.S. Sugar's draft Title V Permit.
2. Page 6, Specific Condition No. 6 – Replace "3-hour block average" and "24-hour block average" with the terms "3-hour block" and "24-hour block" as the applicable fuel-use limits are totals and not averages for their respective periods.
3. Page 11, Specific Condition No. 22 – Replace "daily logs" with "Daily Operational Records" (as in Specific Condition 22 g.).
4. Page 11, Specific Condition No. 22 e. - Replace "3-hour and 24-hour block averages" with "3-hour and 24-hour block totals".
5. Page 12, Specific Condition No. 23 – To calculate the data availability for all monitored parameters is very burdensome and not known to be imposed on similar facilities even as periodic monitoring under Title V. Please remove this requirement or limit calculation of data availability to steam rate and fuel oil usage rate.

If you have any questions concerning the information provided in this application, please call me at (352) 336-5600, Ext. 545.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

Seal

DB/SM/jkk

Enclosures

cc: Don Griffin
Bill Wehrum

CC: J. Koerner
C. Holladay
SD

Table 1. Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analyses - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	29.9	310	1200	87123124
	31.1	270	1200	88123124
	33.9	310	1200	89123124
	35.8	310	1200	90123124
	33.2	300	1200	91123124
H2H 24-Hour				
	231	310	1200	87080724
	240	310	1200	88040324
	217	320	900	89061524
	208	320	900	90031624
	203	320	1200	91041624
H2H 3-Hour				
	552	310	900	87080715
	615	310	900	88090912
	574	310	900	89061212
	561	270	900	90092115
	728	310	900	91070615
PM_{10}				
Annual				
	5.5	310	1200	87123124
	5.7	270	1200	88123124
	6.4	310	1200	89123124
	6.8	310	1200	90123124
	6.3	300	1200	91123124
H2H 24-Hour				
	48.7	270	1200	87123124
	49.0	310	1500	88112024
	45.2	320	900	89060424
	43.9	320	1200	90020324
	44.3	290	1200	91050924
CO				
H2H 8-Hour				
	3781	310	900	87061416
	3824	280	1200	88032408
	3978	320	900	89060516
	3323	320	1200	90031508
	4211	310	900	91043016
H2H 1-Hour				
	7822	340	900	87072410
	7798	320	900	88040612
	7930	320	900	89051714
	8872	330	527	90080511
	9124	40	600	91081212

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 2. Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration (mg/m^3)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS (mg/m^3)
	Total	Modeled	ackground	Direction (degree)	Distance (m)		
SO_2							
Annual	39.7	34.7	5	316	1100	89123124	60
	40.9	35.9	5	310	1100	90123124	
	38.2	33.2	5	300	1200	91123124	
H2H 24-Hour	258	245	13	316	1100	87032424	260
	253	240	13	310	1200	88040324	
H2H 3-Hour	775	728	47	310	900	91070615	1300
PM_{10}							
Annual	29.6	6.6	23	316	1100	89123124	50
	29.8	6.8	23	310	1100	90123124	
H2H 24-Hour	90	51	39	272	1100	87123124	150
	88	49	39	310	1500	88112024	
CO							
H2H 8-Hour	7761	4331	3430	318	900	89060416	10000
	7681	4251	3430	310	800	91043016	
H2H 1-Hour	14839	9124	5715	40	600	91081212	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 3. Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis
- Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (mg/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	0.1	250	11000	87123124
	0.0	0	0	88123124
	0.0	0	0	89123124
	0.1	210	11000	90123124
	0.0	0	0	91123124
H2H 24-Hour				
	7	30	11000	87030524
	9	350	11000	88060224
	12	80	11000	89040224
	11	100	11000	90042124
	8	50	11000	91040824
H2H 3-Hour				
	29	60	11000	87041324
	46	60	11000	88040521
	48	70	11000	89041303
	33	120	11000	90042203
	36	80	11000	91041121
PM_{10}				
Annual				
	<0	0	0	87123124
	<0	0	0	88123124
	<0	0	0	89123124
	<0	0	0	90123124
	<0	0	0	91123124
H2H 24-Hour				
	4.9	320	900	87100624
	6.4	330	900	88062824
	5.9	350	900	89073024
	5.4	310	900	90082924
	6.0	310	900	91083124

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 4. Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment ($\mu g/m^3$)
		Direction (degree)	Distance (m)		
SO_2					
Annual	0.1	250	11000	87123124	20
H2H 24-Hour	12.2	78	11000	89042324	91
H2H 3-Hour	47.7	70	11000	89041303	512
PM_{10}					
Annual	<0	0	0	0	17
H2H 24-Hour	7.6	332	1200	88081424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

Table 5. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (ug/m^3)
Annual					
	0.16	550300	2848600	87123124	2
	0.14	535000	2848600	88123124	
	0.10	540000	2848600	89123124	
	0.20	545000	2848600	90123124	
	0.09	540000	2848600	91123124	
H2H 24-Hour					
	2.3	550300	2848600	87052924	5
	3.0	545000	2848600	88060224	
	2.8	545000	2848600	89040124	
	3.2	530000	2848600	90041224	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.5	530000	2848600	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:

PSD = Prevention of Significant Deterioration

YYMMDDHH = Year, Month, Day, Hour Ending

UTM = Universal Transverse Mercator

H2H = Highest, 2nd-Highest

Table 6. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation:

(09/20/99)

Boilers 1-3 @ 2.5% sulfur fuel oil; 182 ft stack height
Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
3	342.0 [c]	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	633.0	225.1	1,500	213.0	420.0	58,333	153.3	42.0 [d]	195.3	24.61
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	798.0	1,980.2	275,028	1,752.3	232.0	1,984.3	250.0
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
2	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
3	342.0	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	600.0	225.1	0	0.0	600.0	83,333	0.0	60.0 [d]	60.0	7.56
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,517.0	239.5	1,756.5	221.3

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions, i.e., Boiler Nos. 1, 2 and 3 burning 2.5% sulfur oil, and Boiler No.4 burning 0.7% sulfur oil. Boiler Nos. 1, 2 and 3 have 182 ft stacks, and Boiler No. 4 has a 150 ft stack.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 2.5% sulfur: 18,300 Btu/lb; 150,000 Btu/gal; 8.2 lb/gal
0.7% sulfur: 19,450 Btu/lb; 142,000 Btu/gal; 7.3 lb/gal
Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

Table 7. U.S. Sugar Clewiston Boiler Maximum PM10 and CO Emissions - Future Configuration

Source	Maximum Heat Input (MMBtu/hr)	Emission Factor		Emissions (lb/hr)	Emissions (g/s)
		MAXIMUM 24-HOUR CASE - PM10 EMISSIONS			
Boilers		PM Emission Factor	PM10 Emission Factor		
Boiler 1	495.6	0.25 lb/MMBtu	93% of PM	115.2	14.52
Boiler 2	495.6	0.25 lb/MMBtu	93% of PM	115.2	14.52
Boiler 3	342.0	0.30 lb/MMBtu	93% of PM	95.4	12.02
Boiler 4	600.0	0.15 lb/MMBtu	93% of PM	83.7	10.55
Boiler 7	738.0	0.03 lb/MMBtu	100% of PM	22.1	2.79
		MAXIMUM 1-HOUR CASE - CO EMISSIONS			
Boilers					
Boiler 1	495.6	13.0 lb/MMBtu		6,442.80	811.79
Boiler 2	495.6	13.0 lb/MMBtu		6,442.80	811.79
Boiler 3	342.0	10.0 lb/MMBtu		3,420.00	430.92
Boiler 4	633.0	6.5 lb/MMBtu		4,114.50	518.43
Boiler 7	812.0	0.7 lb/MMBtu		568.40	71.62
		MAXIMUM 8-HOUR CASE - CO EMISSIONS			
Boilers					
Boiler 1	495.6	9.2 lb/MMBtu		4,559.52	574.50
Boiler 2	495.6	12.5 lb/MMBtu		6,195.00	780.57
Boiler 3	342.0	9.1 lb/MMBtu		3,112.20	392.14
Boiler 4	633.0	6.5 lb/MMBtu		4,114.50	518.43
Boiler 7	812.0	0.7 lb/MMBtu		568.40	71.62

Note: PM emissions are based on allowable emission rates for bagasse firing.
CO emissions for Boiler Nos. 1, 2 and 3 are based on actual test data.
CO emissions for Boiler Nos. 4 and 7 are based on allowable emission rates for bagasse firing.

Table 8. Future Maximum Annual Emissions, Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 12/17/99)

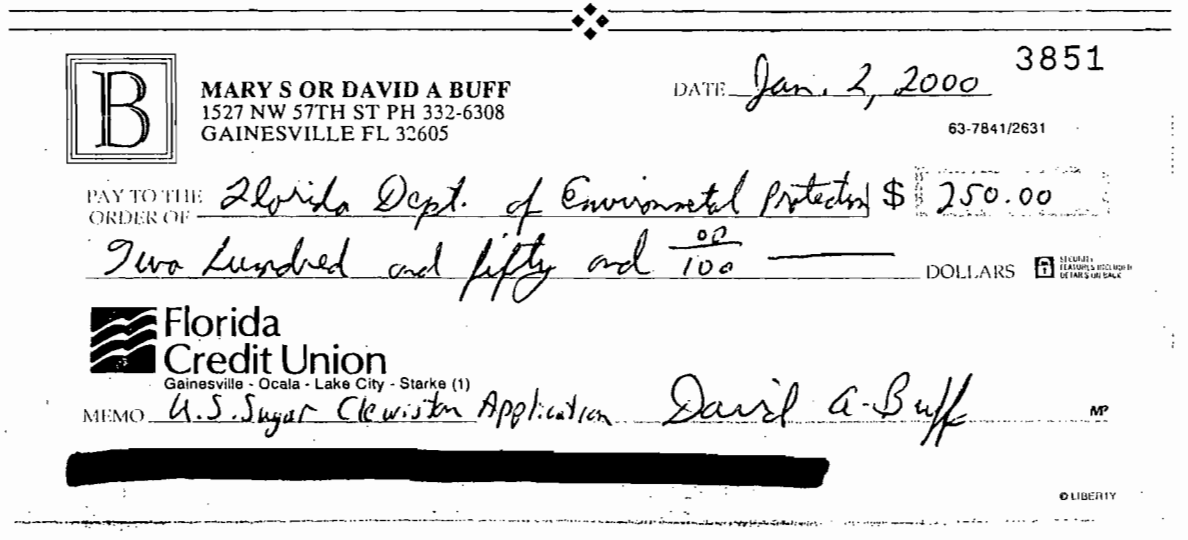
Pollutant	Bagasse Firing			Fuel Oil Firing			Total Emissions (TPY)
	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	
Particulate Matter (PM)	0.15 lb/MMBtu	2,880,000	216.0	0.1 lb/MMBtu	0	0.0	216.0
PM10	0.14 lb/MMBtu	2,880,000	201.6	0.1 lb/MMBtu	0	0.0	201.6
Sulfur Dioxide	0.1 lb/MMBtu	2,805,000	140.3	0.72 lb/MMBtu (b)	75,000	27.0	167.3
Nitrogen Oxides	0.2 lb/MMBtu	2,805,000	280.5	0.31 lb/MMBtu	75,000	11.6	292.1
Carbon Monoxide	6.5 lb/MMBtu	2,880,000	9,360.0	0.033 lb/MMBtu	0	0.0	9,360
Volatile Organic Compounds	0.5 lb/MMBtu	2,880,000	720.0	0.0019 lb/MMBtu	0	0.0	720
Sulfuric Acid Mist	0.006 lb/MMBtu	2,880,000	8.8	0.044 lb/MMBtu	0	0.0	8.82
Lead	4.45E-04 lb/MMBtu	2,880,000	0.6	1.01E-05 lb/MMBtu	0	0.0	0.64
Mercury	3.80E-05 lb/MMBtu	2,880,000	0.1	7.53E-07 lb/MMBtu	0	0.0	0.055
Beryllium	--	2,805,000	0.0	1.85E-07 lb/MMBtu	75,000	6.94E-06	6.94E-06

(a) Total heat input based on total steam production of 1.368E+09 lb steam/yr, 1,160 Btu/lb steam and 55% thermal efficiency.
Fuel oil considered where worst case emission factor is due to oil burning. Maximum fuel oil burning is 500,000 gal/yr, equivalent to 75,000 MMBtu/yr.

(b) Represents maximum sulfur content of 0.7% for fuel oil.

Table 9. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (revised 12/17/99)

Regulated Pollutant	Emission Factor (lb/MMBtu)	Reference	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceuos Fuel			
Particulate Matter (PM)	0.15	1	633	600	95.0	90.0
Particulate Matter (PM10)	0.14	2	633	600	88.3	83.7
Sulfur dioxide	0.1	3	633	600	63.3	60.0
Nitrogen oxides	0.20	4	633	600	126.6	120.0
Carbon monoxide	6.5	1	633	600	4,114.5	3900.0
VOC	0.5	5	633	600	316.5	300.0
Sulfuric Acid Mist	0.006	6	633	600	3.9	3.7
Lead	4.45E-04	7	633	600	0.28	0.27
Mercury	3.8E-05	8	633	600	0.0241	0.0228
Beryllium	--	7	633	600	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	225	--	22.5	22.5
Particulate Matter (PM10)	0.10	9	225	--	22.5	22.5
Sulfur dioxide (b)	0.72	10	225	--	162.0	162.0
Nitrogen oxides	0.31	11	225	--	69.8	69.8
Carbon monoxide	0.033	11	225	--	7.5	7.5
VOC	0.0019	11	225	--	0.4	0.4
Sulfuric Acid Mist	0.044	6	225	--	9.9	9.9
Lead	1.01E-05	11	225	--	2.27E-03	2.27E-03
Mercury	7.53E-07	11	225	--	1.70E-04	1.70E-04
Beryllium	1.85E-07	11	225	--	4.17E-05	4.17E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			530	499	68.3	63.6
Particulate Matter (PM10)			530	499	65.1	60.7
Sulfur dioxide			530	499	192.6	189.4
Nitrogen oxides			530	499	130.9	124.5
Carbon monoxide			530	499	1,993.3	1787.2
VOC			530	499	153.2	137.3
Sulfuric Acid Mist			530	499	11.8	11.6
Lead			530	499	0.14	0.12
Mercury			530	499	0.012	0.011
Beryllium			530	499	4.17E-05	4.17E-05
			Maximum Any Combination			
Particulate Matter (PM)					95.0	90.0
Particulate Matter (PM10)					88.3	83.7
Sulfur dioxide					192.6	189.4
Nitrogen oxides					130.9	124.5
Carbon monoxide					4,114.5	3,900.0
VOC					316.5	300.0
Sulfuric Acid Mist					11.8	11.6
Lead					0.28	0.27
Mercury					0.0241	0.0228
Beryllium					4.17E-05	4.17E-05



MARY S OR DAVID A BUFF
1527 NW 57TH ST PH 332-6308
GAINESVILLE FL 32605

3851

DATE Jan. 2, 2000

63-7841/2631

PAY TO THE ORDER OF Florida Dept. of Environmental Protection $ 250.00

Two Hundred and fifty and 00/100 DOLLARS

Florida Credit Union
Gainesville - Ocala - Lake City - Starke (1)

MEMO U.S. Sugar Clewiston Application David A. Buff

[redacted]

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Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 300,000 lb/hr at 600 psig, 750 F.
Maximum 6-hour average activity factor based on steam production rate of 285,000 lb/hr at 600 psig, 750 F.
Enthalpy of steam = 1,378 Btu/lb. Enthalpy of feedwater = 218 Btu/lb. Net enthalpy = 1,160 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (300,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 168 MMBtu/hr
Required heat input to boiler from bagasse = 168 MMBtu/hr / 55% eff. = 305.5 MMBtu/hr
Total heat input required = 225 + 305.5 = 530 MMBtu/hr
Max 24-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (285,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 150.6 MMBtu/hr
Required heat input to boiler from bagasse = 150.6 MMBtu/hr / 55% eff. = 273.8 MMBtu/hr
Total heat input required = 225 + 274 = 499 MMBtu/hr

(b) The SO2 emission factor reflects the maximum sulfur content (0.7%). Boiler Nos. 1, 2 and 3 are permitted to burn up to 2.5% sulfur fuel oil.

References

1. Current BACT permit limit for Clewiston.
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Proposed BACT limit, based on actual stack testing on Clewiston boilers. Equivalent to 0.1% sulfur content of bagasse (wet), 3,600 Btu/lb(wet); and 82% removal in wet scrubber.
4. Equivalent to current permit limit for Clewiston Boiler No. 4.
5. Proposed permit limit.
6. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
7. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
8. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
9. Assumed as 100% of PM emissions.
10. Based on 0.7% S fuel oil; 142,000 Btu/gal; 7.3 lb/gal; assumes 100% conversion of sulfur to SO2.
11. Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Multiple Fuel Combustion:
= {(Bagasse Activity Factor - Fuel Oil Activity Factor) x Bagasse Emission Factor}
+ (Fuel Oil Activity Factor x Fuel Oil Emission Factor)

Table 10. Summary of Finalized Source Parameters Used in the Modeling Analysis of U.S. Sugar's Clewiston Mill

Emission Unit	Modeling ID	Stack Height		Stack Diameter		Temperature		Flow Rate		Velocity		Relative Location (a)			
												X		Y	
		(ft)	(m)	(ft)	(m)	(F)	(K)	(dscfm)	(acfm)	(ft/s)	(m/s)	(ft)	(m)	(ft)	(m)
Boiler 1	USSBLR1	182	55.5	8.00	2.44	165	347.0	--	190,000	63.0	19.2	200.1	61.0	9.8	3.0
Boiler 2	USSBLR2	182	55.5	8.00	2.44	150	338.7	--	190,000	63.0	19.2	164.0	50.0	9.8	3.0
Boiler 3	USSBLR3	182	55.5	8.00	2.44	140	333.2	--	108,000	35.8	10.9	111.5	34.0	36.1	11.0
Boiler 4	USSBLR4	150	45.7	8.25	2.51	160	344.3	--	266,800	83.2	25.4	0.0	0.0	0.0	0.0
Boiler 7	USSBLR7	225	68.6	8.50	2.59	270	405.4	--	290,000	85.2	26.0	-131.6	-40.1	21.7	6.6

(a) Relative to Boiler No. 4 stack location.

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT – TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

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

Application Contact

1. Name and Title of Application Contact: **Murray T. Brinson, Vice President**
2. Application Contact Mailing Address: Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce DeLeon Av PO Dr 1207** City: **Clewiston** State: **FL** Zip Code: **33440**
3. Application Contact Telephone Numbers: Telephone: (**941**) **983 - 8121** Fax: (**941**) **902 - 2729**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:_____

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:_____

Operation permit number to be revised:_____

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:_____

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:_____

Reason for revision:_____

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[**X**] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   Murray T. Brinson, Vice President
2. Owner/Authorized Representative or Responsible Official Mailing Address:
   Organization/Firm: **United State Sugar Corporation**
   Street Address: **111 Ponce DeLeon Ave.**
   City: **Clewiston** State: **FL** Zip Code: **33440**
3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: **(941) 983 - 8121** Fax: **(941) 902 - 2729**
4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative(check here [ ], if so) or the responsible official (check here [X], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

Signature Date 12/17/99

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

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

4. Professional Engineer Statement :

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

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

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

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

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

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

David A. Buff
Signature

12/17/99
Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
009	Boiler No. 4	AC1A	
	Sugar Processing Operation	AC1A	

Application Processing Fee

Check one: [X] Attached - Amount: $: **$250.00** [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations:

   Increase maximum annual heat input for Boiler No. 4 from 2.713 * 10^12 Btu/yr to 2.880 * 10^12 lb/yr, with no restriction on operating hours. Expand existing sugar processing operation. Submitted in accordance with Interim Permit Condition No. 7 of Permit No. 0510003-009-AC (PSD-FL-272).

2. Projected or Actual Date of Commencement of Construction **1 Aug 1999**

3. Projected Date of Completion of Construction: **1 Jun 2000**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **506.1** North (km): **2956.9**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **26 / 44 / 6** Longitude (DD/MM/SS): **80 / 56 / 19**			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **20**	6. Facility SIC(s): **2061, 2062**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Murray T. Brinson, Vice President**
2. Facility Contact Mailing Address: Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce DeLeon Av PO Dr 1207** City: **Clewiston** State: **FL** Zip Code: **33440**
3. Facility Contact Telephone Numbers: Telephone: (**941**) **983 - 8121** Fax: (**941**) **902 - 2729**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **See Attachment UC-FI-11**	

List of Applicable Regulations

Title V Core List, effective date 3/25/97, and additional applicable requirements attached.	

Title V Core List

Effective:03/25/97

[**Note:** The Title V Core List is intended to simplify the completion of the "List of Applicable Regulations" that apply facility-wide (see Subsection II.B. of DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.

Requirements that apply to emissions units must be identified in Subsection III.B. of DEP Form No. 62-210.900(1), Application for Air Permit - Long Form.

Applicants must identify all "applicable requirements" in order to claim the "permit shield" described at Rule 62-213.460, F.A.C.]

Federal: ***(description)***

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)
40 CFR 61, Subpart M: NESHAP for Asbestos.

~~40 CFR 82: Protection of Stratospheric Ozone.~~
~~40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).~~
~~40 CFR 82, Subpart F: Recycling and Emissions Reduction.~~

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 10-16-95

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-103, F.A.C.: RULES OF ADMINISTRATIVE PROCEDURE, effective 12-31-95

62-103.150, F.A.C.: Public Notice of Application and Proposed Agency Action.
62-103.155, F.A.C.: Petition for Administrative Hearing; Waiver of Right to Administrative Proceeding

Title V Core List Effective:03/25/97

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 03-21-96

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(3)(a), F.A.C.: Full Exemptions.
62-210.300(3)(b), F.A.C.: Temporary Exemption.

62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.

62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.

62-210.650, F.A.C.: Circumvention.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1) Application for Air Permit - Long Form, Form and Instructions.
62-210.900(5) Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 03-20-96

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1) Major Air Pollution Source Annual Emissions Fee Form, Form and Instructions.

Title V Core List

Effective:03/25/97

CHAPTER 62-256, F.A.C.: OPEN BURNING AND FROST PROTECTION FIRES, effective 11-30-94

CHAPTER 62-257, F.A.C: ASBESTOS NOTIFICATION AND FEE, effective 03/24/96

~~**CHAPTER 62-281, F.A.C: MOTOR VEHICLE AIR CONDITIONING REFRIGERANT RECOVERY AND RECYCLING,** effective 03-07-96~~

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-13-96

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.
62-296.320(3), F.A.C.: Industrial, Commercial, and Municipal Open Burning Prohibited
62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter

Identification of Additional Applicable Requirements

Applicable Requirements, as defined in Rule 62-210.200(29), but not identified in the attached Core List, are included in this attachment entitled "**Identification of Additional Applicable Requirements**". Only those rules, regulations, and ordinances specifically identified on the Title V Core List (effective date 3/25/97) or herein, apply to this facility.

FACILITY

State

62-210.700(1), F.A.C.:	Excess Emissions
62-210.700(4), F.A.C.:	Excess Emissions
62-210.700(6), F.A.C.:	Excess Emissions
62-256.300, F.A.C.:	Open Burning - Prohibitions
62-256.400, F.A.C.:	Open Burning - Agricultural and Silvicultural Fires
62-256.500, F.A.C.:	Open Burning - Land Clearing
62-256.600, F.A.C.:	Open Burning - Industrial, Commercial, Municipal and Research Open Burning
62-296.320(4)(b), F.A.C.:	General VE Standards

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	A				Particulate Matter – Total
SO_2	A				Sulfur Dioxide
NO_X	A				Nitrogen Oxides
VOC	A				Volatile Organic Compounds
CO	A				Carbon Monoxide
PM_{10}	A				Particulate Matter – PM_{10}
SAM	A				Sulfuric Acid Mist
PB	B				Lead - Total

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: UC-FE-1 [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: UC-FE-2 [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: UC-FE-3 [X] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: _____ [X] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID: _____ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD Report [ ] Not Applicable
7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities:
   [ ] Attached, Document ID:_____ [ ] Not Applicable

9. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID:_____
   [ ] Equipment/Activities On site but Not Required to be Individually Listed
   [ ] Not Applicable

10. Alternative Methods of Operation:
    [ ] Attached, Document ID:_____ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading):
    [ ] Attached, Document ID:_____ [ ] Not Applicable

12. Identification of Additional Applicable Requirements:
    [ ] Attached, Document ID:_____ [ ] Not Applicable

13. Risk Management Plan Verification:
    [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:_____) or previously submitted to DEP (Date and DEP Office:_____)
    [ ] Plan to be submitted to CEPPO (Date required:_____)
    [ ] Not Applicable

14. Compliance Report and Plan:
    [ ] Attached, Document ID:_____ [ ] Not Applicable

15. Compliance Certification (Hard-copy Required):
    [ ] Attached, Document ID:_____ [ ] Not Applicable

ATTACHMENT UC-FA-7

FACILITY COMMENT

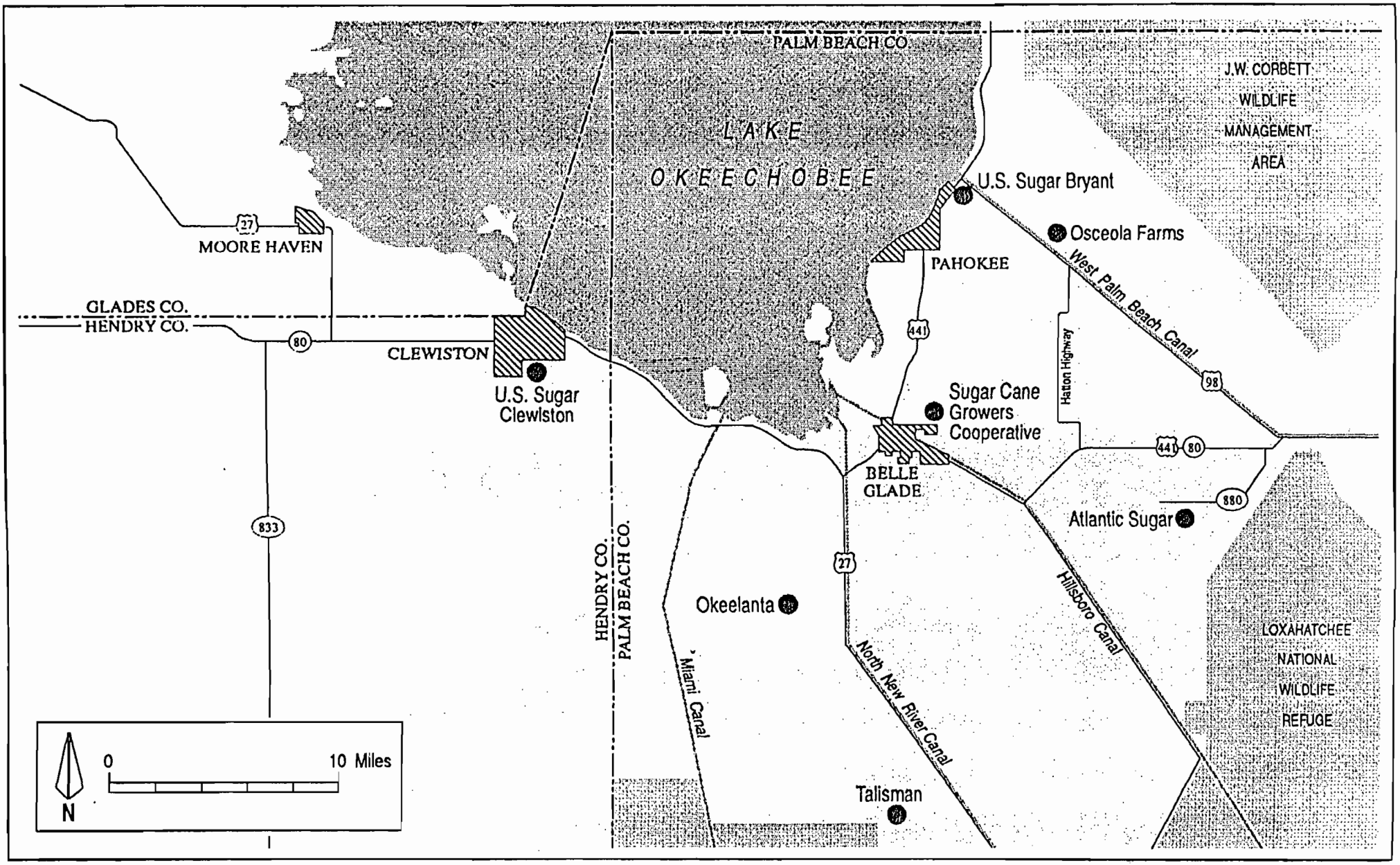
ATTACHMENT UC-FA-7

Operations at U.S. Sugar Corporation Clewiston sugar mill involve raw sugar manufacturing from sugar cane and raw sugar refining. In reference to the facility flow diagram (Attachment UC-FE-3), based on historical agricultural crop seasons, up to 30,000 tons of cane can be processed per day. U.S. Sugar has the ability to transfer sugar cane and other products between the Bryant and Clewiston mills based on agricultural, processing, logistical, and other considerations.

As set forth in the Boiler No. 4 construction permit amendment, the total No. 6 fuel oil consumption for Boiler Nos. 1, 2, 3, and 4 located at the facility shall not exceed 88,000 gallons (gal) during any 24-hour period, or 16,200 gal during any 3-hour period.

ATTACHMENT UC-FE-1

AREA MAP



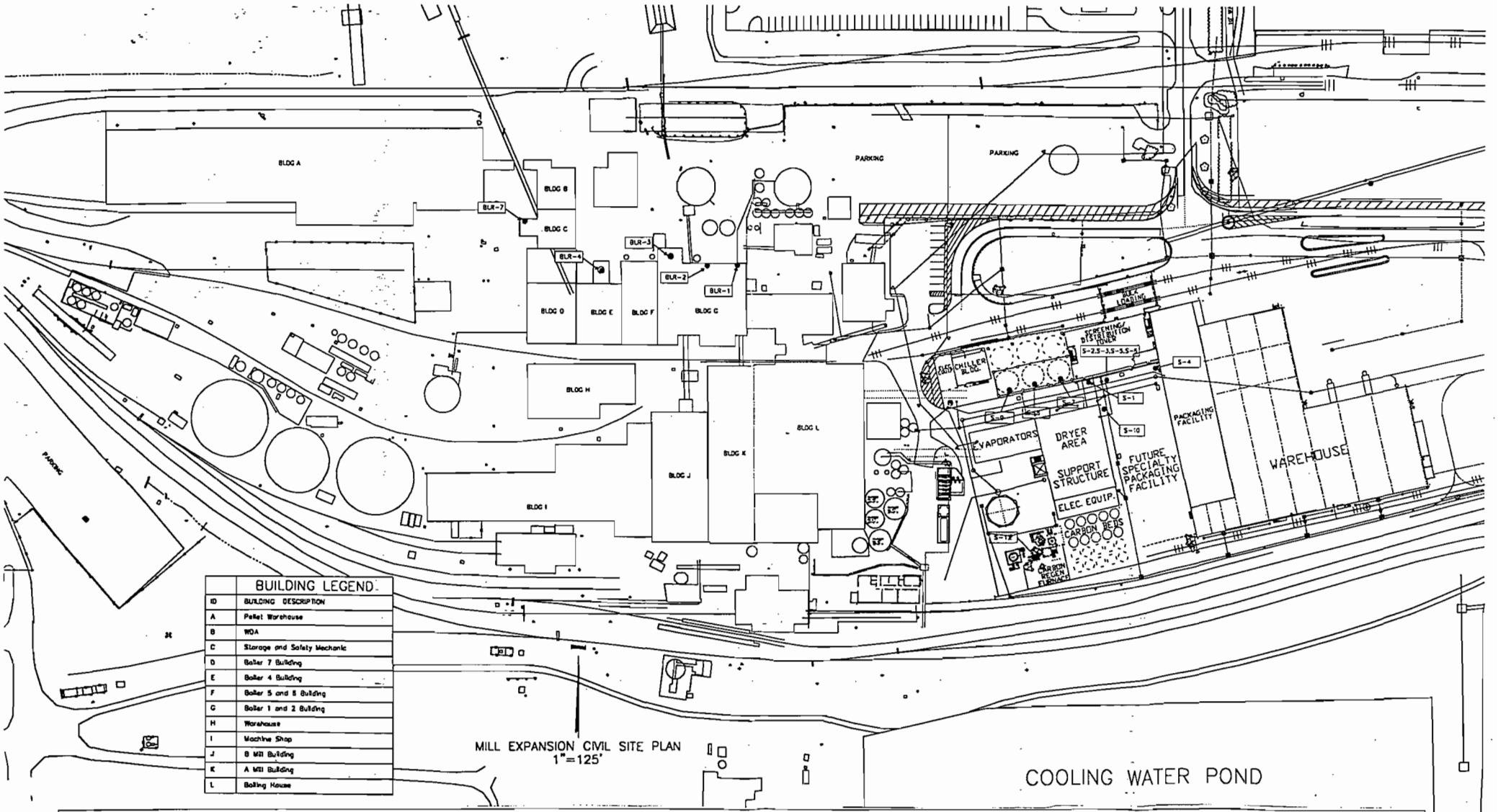
Attachment UC-FE-1
Location of U.S. Sugar Mill, Clewiston, Florida

Source: KBN, 1995.

Golder Associates

ATTACHMENT UC-FE-2

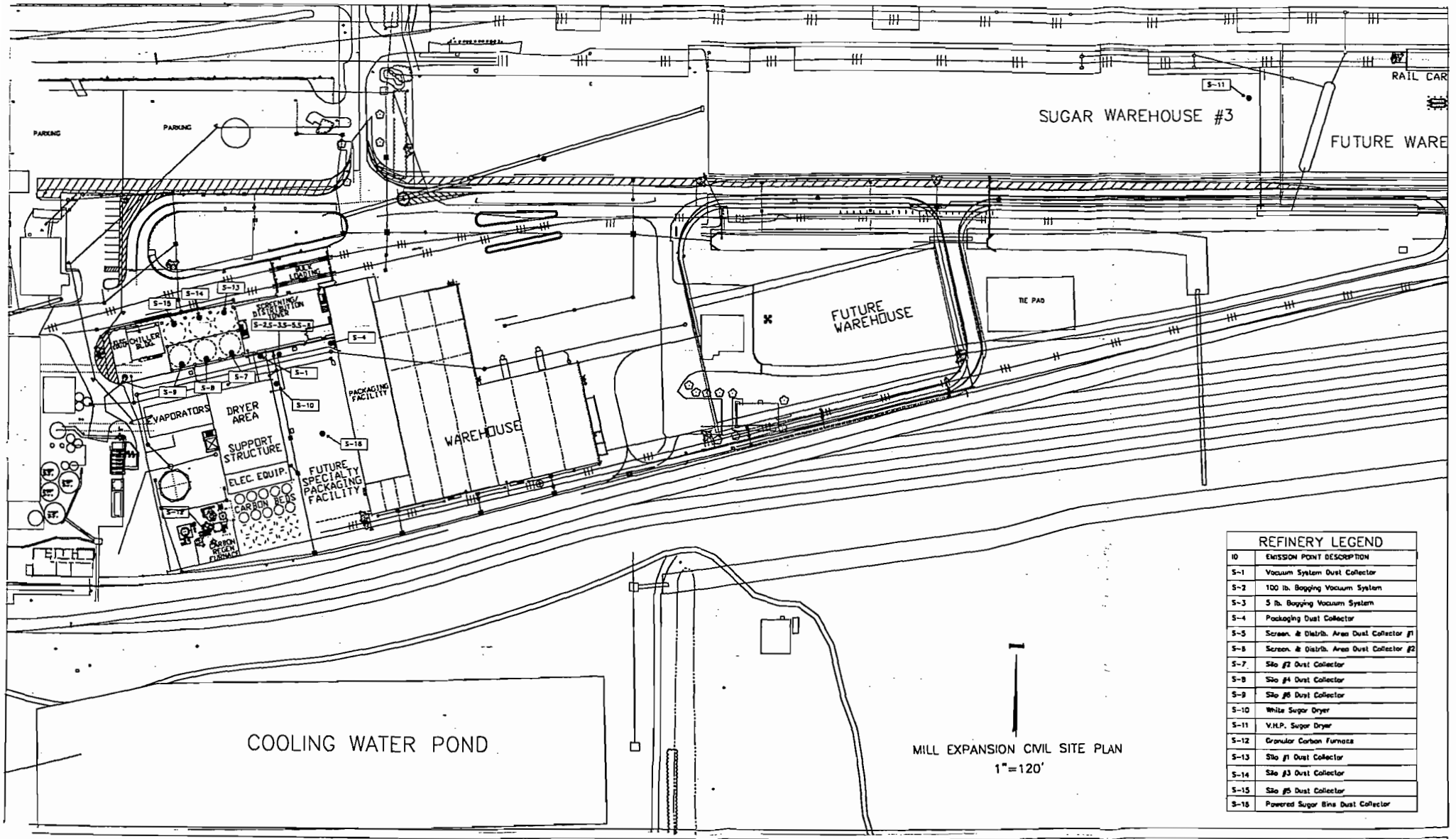
FACILITY PLOT PLAN



Attachment UC-FE-2, Page 1. Clewiston Mill Plot Plan of Existing Sources and Major Buildings

Boiler No. 4/ Sugar Refinery, U.S. Sugar Corporation, Clewiston, Florida

Golder Associates



REFINERY LEGEND	
ID	EMISSION POINT DESCRIPTION
S-1	Vacuum System Dust Collector
S-2	100 lb. Bagging Vacuum System
S-3	5 lb. Bagging Vacuum System
S-4	Packaging Dust Collector
S-5	Screen. & Distrib. Area Dust Collector #1
S-6	Screen. & Distrib. Area Dust Collector #2
S-7	Silo #2 Dust Collector
S-8	Silo #4 Dust Collector
S-9	Silo #6 Dust Collector
S-10	White Sugar Dryer
S-11	V.H.P. Sugar Dryer
S-12	Granular Carbon Furnace
S-13	Silo #1 Dust Collector
S-14	Silo #3 Dust Collector
S-15	Silo #5 Dust Collector
S-16	Powered Sugar Bins Dust Collector

Attachment UC-FE-2, Page 2. Location of Sugar Refinery Sources and Major Buildings

Boiler No. 4/ Sugar Refinery, U.S. Sugar Corporation, Clewiston, Florida

Golder Associates

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			**633**	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:	**300,000 lb/hr of steam**			
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Rates are max 3-hr avg. The max 24-hr avg is 600 MMBtu/hr and 285,000 lb/hr steam. Max fuel oil firing = 225 MMBtu/hr. Annual heat input cap = 2.88 x 10^12 Btu/yr.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **External combustion boilers; Industrial; Bagasse; All boiler sizes.**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **87.92**	5. Maximum Annual Rate: **400,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **7**
10. Segment Comment (limit to 200 characters): **Based on 3,600 Btu/lb wet bagasse and 633 MMBtu/hr heat input rate. Annual rate based on equivalent of 200 days operation at 600 MMBtu/hr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **External combustion boilers; Industrial; Residual oil; Grade 6 oil**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.5**	5. Maximum Annual Rate: **500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.7**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **142**
10. Segment Comment (limit to 200 characters): **Max hourly and annual rates based on permit specific conditions.**		

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **192.6** lb/hour **167.3** tons/year		4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year		
6. Emission Factor: **0.7 %S** Reference: **Fuel Sulfur Limit**		7. Emissions Method Code: **0**

8. Calculation of Emissions (limit to 600 characters):

See Table 8 for calculation of the annual emission rate. See Table 9 for calculation of the hourly emission rate.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Max hourly emissions representative of combined carbonaceous fuel and fuel oil firing.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.7 % Sulfur Oil**	4. Equivalent Allowable Emissions: **192.6** lb/hour **167.3** tons/year

5. Method of Compliance (limit to 60 characters):

EPA Method 6 or 6C

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Applies to total combined carbonaceous fuel and fuel oil firing.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **63.3** lb/hour **140.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 6 or 6C**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applies to carbonaceous fuel firing only.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.7 %S fuel oil**	4. Equivalent Allowable Emissions: **162.0** lb/hour **27.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on max heat input of 225 MMBtu/hr from fuel oil firing and assumes no removal in wet scrubber. Annual emission based on 500,000 gal/yr.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **130.9** lb/hour **292.1** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **0.2 lb/MMBtu** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **See Table 8 for calculation of the annual emission rate. See Table 9 for calculation of the hourly emission rate.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max annual emissions representative of combined carbonaceous fuel firing and No. 6 fuel oil firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **126.6** lb/hour **280.5** tons/year
5. Method of Compliance (limit to 60 characters): **Operation and Maintenance Plan**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Permit limit relating to carbonaceous fuel firing.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4,114.5** lb/hour **9,360** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **6.5 lb/MMBtu** Reference: **Permit Condition**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **See Table 8 for calculation of the annual emission rate. See Table 9 for calculation of the hourly emission rate.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max emissions representative of carbonaceous fuel firing. Annual emissions based on heat input rate of 2,880,000 MMBtu/yr.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.5 lb/MMBtu**	4. Equivalent Allowable Emissions: **4,114.5** lb/hour **9,360** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable based on current permit limit. Annual emissions based on heat input rate of 2,880,000 MMBtu/yr.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **316.5** lb/hour **720** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: **0.5 lb/MMBtu** Reference: **Permit Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **See Table 8 for calculation of the annual emission rate. See Table 9 for calculation of the hourly emission rate.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max emissions representative of carbonaceous fuel firing. Annual emissions based on heat input rate of 2,880,000 MMBtu/yr.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.5 lb/MMBtu**	4. Equivalent Allowable Emissions: **316.5** lb/hour **720** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Golder Associates Inc.

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

October 20, 1999 9937515

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention: Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
INFORMATION SUBMITTAL NO. 5

Dear Mr. Koerner:

Based on my conversations last week with Cleve Holladay, and Stan Krivo at EPA Region 4, regarding U.S. Sugar's PSD permit application to modify operation of Boiler No. 4 and expand the sugar refinery operation, a few additional questions have been raised in regards to approval of the ISC-PRIME model for the Clewiston mill. The purpose of this letter is to respond to these questions. The questions and our response are provided below.

1. Attached is a diagram showing the location of the Boiler No. 4 stack and other stacks at U.S. Sugar in relation to buildings. A scale is provided on the diagram. Please use this diagram in conjunction with Attachment UC-FE-2 included in the permit application form, and with building information presented in Section 6.0 of the PSD report (page 6-13 and Table 6-13).

2. Regarding baseline emissions used for Boiler No. 4 in the significant impact analysis, the following information is provided. Attached is Table A (filename: Blr4sig.xls) which summarizes the baseline emissions used in the significant impact analysis. All baseline emissions are based on the actual emission factors for Boiler No. 4 obtained from source testing (refer Appendix B, Table B-1). The emission factors used in this table are the same as those used to calculate the current actual annual emissions for PSD source applicability (see table 3-3 of PSD report). For all but NO_x, the boiler heat input rate used to calculate the baseline emissions were based on actual historical boiler operation, and was 546 MMBtu/hr for the 24-hour averaging time (for PM/PM_{10}), and 600 MMBtu/hr for the 1-hour averaging time. For SO_2, it was conservatively assumed that no fuel oil burning was occurring, and that the SO_2 was solely due to bagasse firing. In the case of NO_x, the baseline emissions were conservatively based on the actual annual baseline NO_x emissions (70.6 TPY from Table 3-3) and then dividing by 8,760 hr/yr. This would

render the baseline NO_x emissions lower as actual operation has been only 160 days/yr (3,840 hr/yr) or less.

3. The CO and PM_{10} emissions used in the AAQS/PSD modeling for other boilers at U.S. Sugar Clewiston were shown in Table 6-4 of the PSD report. These emissions should match the model input files. For PM_{10} emissions, the emissions are based on the permit limits for PM for each boiler. For CO, the emission factors are based on actual CO test data available for each boiler (a revised Table 6-4 was forwarded to Jeff Koerner at FDEP on Sep. 22, 1999).

4. All other questions should be addressed by Steve Mark's e-mail to Cleve Holladay and Stan Krivo dated Oct. 14, 1999. Steve has place all model input/output data onto the Golder FTP site.

Thank you for consideration of this information. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/jkk

Enclosures

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV

\\GATORBAIT\DP\Projects\99\9937\9937515a\05\#05ltr.doc

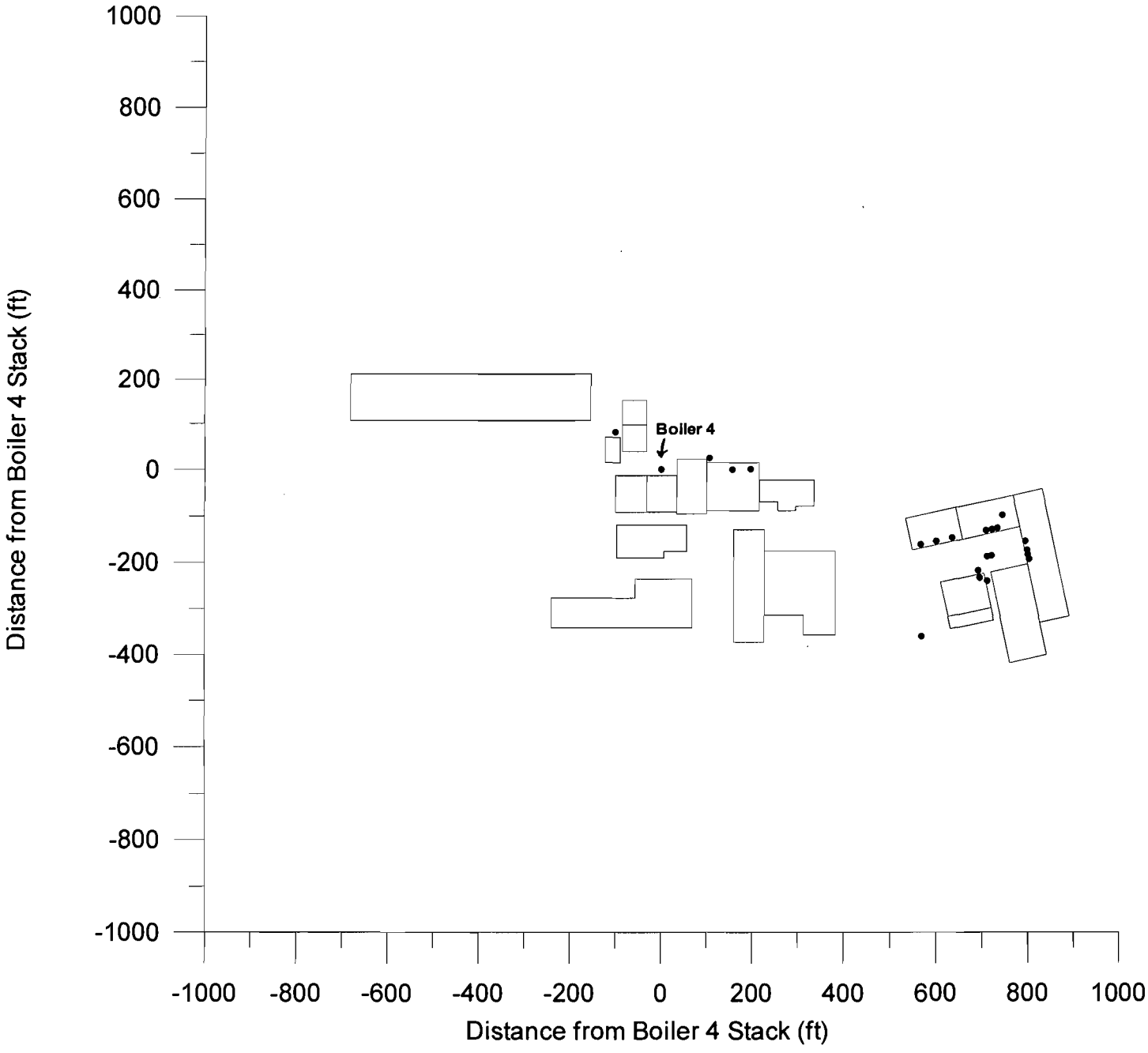
cc: SFD
EPA
NPS
File
C. Holladay, BAR

Table A. Baseline Emissions Used in the Significant Impact Analysis for Clewiston Boiler No. 4

Pollutant	Emission Factor (a)	Heat Input (b) (MMBtu/hr)	Emissions (lb/hr)	Emissions (g/s)
Particulate Matter (PM)	0.12 lb/MMBtu	546	65.5	8.26
PM_{10}	0.112 lb/MMBtu	546	61.2	7.71
Sulfur Dioxide	0.008 lb/MMBtu	600	4.8	0.60
Nitrogen Oxides	0.082 lb/MMBtu	(c)	16.2	2.04
Carbon Monoxide	6.36 lb/MMBtu	600	3816.0	480.82

(a) Based on source test data from Boiler No. 4.
(b) Based on maximum steam rates actually reached in operation for Boiler No. 4.
(c) Based on baseline NOx emissions of 70.9 TPY, assuming 8,760 hr/yr operation.

US Sugar Corp - Clewiston Mill



Golder Associates Inc.

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

RECEIVED
OCT 25 1999
BUREAU OF AIR REGULATION

October 20, 1999

9937515

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention: Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
INFORMATION SUBMITTAL NO. 4

Dear Mr. Koerner:

Based on my conversations this week with Cleve Holladay regarding U.S. Sugar's PSD permit application to modify operation of Boiler No. 4 and expand the sugar refinery operation, a few additional questions have been raised. The purpose of this letter is to respond to these questions. The questions and our response are provided below.

1. In regards to Section 4.0 of the PSD report, the question was raised concerning the background ambient concentration selected for carbon monoxide (CO). In Section 4.2.3 of the PSD report, it was stated that West Palm Beach CO monitoring data was not considered to be representative of the Clewiston area due to the distance from Clewiston to West Palm Beach, and also because of the significant mobile traffic in West Palm Beach compared to Clewiston. The West Palm Beach data was then used for the CO background concentration. Of the three CO monitoring stations operating in 1997, the station with the lowest second-highest 1-hour and 8-hour CO concentration was used.

   I would like to clarify that is was not intended that the West Palm Beach data was not sufficient to use for a background CO concentration. It was intended to state that the West Palm Beach data could in fact be used as a background station for CO, since it would provide a very conservative estimate of background CO in the Clewiston area. Since the West Palm Beach CO data is heavily impacted by mobile traffic, this data would provide a very conservative estimate of background CO concentrations expected to exist in Clewiston. Due to this difference, even use of the lowest of the three CO monitoring stations would provide a conservative estimate of the background concentration.

2. A question was raised regarding Section 7.0, Additional Impact Analysis, in relation to addressing the impacts of the project due to anticipated growth. Since the proposed project is only for the increase in annual steam production (operating time) for the boiler, it is not anticipated that any new employees will be hired by U.S. Sugar as a result of this project. No new construction will take place, except for a new fuel oil tank. The impact on the work force will be minimal. A slight increase in truck traffic entering and leaving the site may result due to increased sugar production, although most of the sugar product is transported by rail.

   In summary, no significant impacts due to associated growth are expected due to the proposed project.

3. In regards to a description of vegetation and soils in the vicinity of the Clewiston mill, a description was provided on page 7-1 of the application.

Thank you for consideration of this information. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/jkk

Enclosures

cc: SFD
EPA
NPS
C. Holladay, BAR
File

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
National Park Service

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UNITED STATES SUGAR CORPORATION

Post Office Box 1207 • Clewiston, Florida 33440-1207
Telephone 941/983-8121

RECEIVED
OCT 19 1999
BUREAU OF AIR REGULATION

October 18, 1999

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

RE: United States Sugar Corporation, Clewiston Sugar Mill, Hendry County
Draft Permit Modifications No. 051-003-009-AC and No. PSD-FL-272)
Extension of Operating Season for Bagasse Boiler No. 4

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

Gentlemen:

We are enclosing the Affidavit of Publication certifying that the "Public Notice of Intent to Issue Air Construction Permit " was duly published in the legal section of the October13th, 1999 issue of *THE CLEWISTON NEWS*.

Sincerely,

UNITED STATES SUGAR CORPORATION

Donald Griffin
Project Manager, Specialty Sugar

DG:kcb
Enclosure
cc: South Florida District, FDEP
David Buff, Golder Associates
Murray T. Brinson, USSC
Bill Raiola, USSC
Lisa Gefen, USSC
Peter Briggs, USSC

J. Koerner, BAR
EPA
NPS

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

he 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 I 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 on. 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, oper , 4 throughout the calendar year, the increase of all refinery operations to full capacity (8760 hours per year). The addition of powered sugar and starch bins and the addition ditioning silos. A Best Available Control Technology (BACT) determination was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM1(ist (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 (

rtment 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 bagass/ .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 c iency. 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% s further control emissions of SAM and SO2 from oil firing. The decolonization process in the refinery operations includes a carbon bed to remove colorant and organic from articulate matter is controlled by a wet venture/tray scrubber system. Emissions of VOC are controlled by a direct flame afterburner. All material handling operations are co fficiency 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 S of VOC.

l application included and air quality analysis based on an air dispersion model (SC-Prime) that has not yet been approved by the EPA. The EPA Region 4 office is currently 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 sugarcan , the applicant also submitted and alternate air quality analysis based on the EPA-approved air dispersion model (ISCST3), decreased fuel sulfur content for Boiler Nos. 1 ectly 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 ad hould EPA Region 4 reject the air quality analysis based on the non-approved model.

ts 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 of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of SO2, and PM10 consumed by all sources in the area, including th e as follows:

s II Increment d (ug/m3)	Allowable Increment (ug/m3)	Percent Increment Consumed
21	31	67
0	17	0
345	512	67
31	91	34
3	20	15

mum predicted PSD Class I increments of SO2 in the Everglades National Park, consumed by all sources in the area, including this project, will be as follows:

s I Increment d (ug/m3)	Allowable Increment (ug/m3)	Percent Increment Consumed
18	25	72
4.1	5	82
0.33	2	17

rtment 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 sig f terms or conditions.

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

rtment 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 th ling a petition. The procedures for petitioning for a hearing are set forth below.

is not available in thus proceeding.

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 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 Boulevar 5, 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 or iled 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 publication of the public n rteen 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 n 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 abov ling. 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 (ions 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 offic of a motion in compliance with Rule 28106.205 of the Florida Administrative Code.

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 a ile 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 represent h 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 agenc (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 n ust 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'

The applicant also submitted and alternate air quality analysis based on the EPA-approved air dispersion model (ISCST3), decreased fuel sulfur content for Boiler Nos. 1 t
ctly 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 ad
hould EPA Region 4 reject the air quality analysis based on the non-approved model.

s 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
f any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of SO2, and PM10 consumed by all sources in the area, including thi
as follows:

II Increment l (ug/m3)	Allowable Increment (ug/m3)	Percent Increment Consumed
21	31	67
0	17	0
345	512	67
31	91	34
3	20	15

num predicted PSD Class I increments of SO2 in the Everglades National Park, consumed by all sources in the area, including this project, will be as follows:

I Increment (ug/m3)	Allowable Increment (ug/m3)	Percent Increment Consumed
18	25	72
4.1	5	82
0.33	2	17

ment 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 sign
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) 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 non
t 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 pro
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 b
lating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action

at 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 informati
ve, as required by rule 28-106.301.

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 po
n 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 pa
ng, in accordance with the requirements set forth above.

project file is available for public inspection during normal business hours, 8 : a.m. to 5 : p.m., Monday through Friday, except legal holidays, at;
of Environmental Protection
ir Regulation
S. Magnolia Drive
Florida, 32301
850) 488-1143

of Environmental Protection
a District Office
295 Victoria Avenue
Florida 33901-3381
941) 332-6975

project file includes the application, technical evaluations, Draft Permit and the information submitted by the responsible official, exclusive of confidential records under
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,
Florida 32301, or call (805) 488-0114, for additional information.

The Clewiston News

Published Weekly Clewiston, Florida

AFFIDAVIT OF PUBLICATION

State of Florida
County of Hendry

Before the undersigned authority, personally appeared Tracy Whirls, who on oath says she is the Managing Editor of the Clewiston News, a weekly newspaper published at Clewiston in Hendry County, Florida, that the attached copy of advertisement, being a Notice in

the matter of Intent

in the

court, was published in

said newspaper in the issues of

October 13, 1999

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

Tracy Whirls

Sworn to and subscribed before me this 13th day

of October, A.D. 19 99.

B K Christiansen

Notary Public

B. K. CHRISTIANSEN
MY COMMISSION # CC 640756
EXPIRES: June 27, 2001
Bonded Thru Notary Public Underwriters

Lyons Printing

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BUREAU OF AIR REGULATION

Golder Associates Inc.

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

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OCT 01 1999
BUREAU OF AIR REGULATION

September 29, 1999

9937515A/3

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL 32399

Attention: Jeffery Koerner, P.E.

RE: United States Sugar Corporation (U.S. Sugar)
PSD Permit Application for Boiler No. 4 and the Sugar Refinery at the Clewiston Mill
Information Submittal No. 4

Dear Mr. Koerner:

Based on my conversations this week with Cleve Holladay regarding U.S. Sugar's PSD permit application to modify operation of Boiler No. 4 and expand the sugar refinery operation, a few additional questions have been raised. The purpose of this letter is to respond to these questions. The questions and our response is provided below.

1. In regards to Section 4.0 of the PSD report, the question was raised concerning the background ambient concentration selected for carbon monoxide (CO). In Section 4.2.3 of the PSD report, it was stated that West Palm Beach CO monitoring data was not considered to be representative of the Clewiston area due to the distance from Clewiston to West Palm Beach, and also because of the significant mobile traffic in West Palm Beach compared to Clewiston. The West Palm Beach data was then used for the CO background concentration. Of the three CO monitoring stations operating in 1997, the station with the lowest second-highest 1-hour and 8-hour CO concentration was used.

   I would like to clarify that is was not intended that the West Palm Beach data was not sufficient to use for a background CO concentration. It was intended to state that the West Palm Beach data could in fact be used as a background station for CO, since it would provide a very conservative estimate of background CO in the Clewiston area. Since the West Palm Beach CO data is heavily impacted by mobile traffic, this data would provide a very conservative estimate of background CO concentrations expected to exist in Clewiston. Due to this difference, even use of the lowest of the three CO monitoring stations would provide a conservative estimate of the background concentration.

2. A question was raised regarding Section 7.0, Additional Impact Analysis, in relation to addressing the impacts of the project due to anticipated growth. Since the proposed project is only for the increase in annual steam production (operating time) for the boiler,

it is not anticipated that any new employees will be hired by U.S. Sugar as a result of this project. No new construction will take place, except for a new fuel oil tank. The impact on the work force will be minimal. A slight increase in truck traffic entering and leaving the site may result due to increased sugar production, although most of the sugar product is transported by rail.

In summary, no significant impacts due to associated growth are expected due to the proposed project.

3. In regards to a description of vegetation and soils in the vicinity of the Clewiston mill, a description was provided on page 7-1 of the application.

Thank you for consideration of this information. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/arz

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
of National Park Service

P:\Projects\99\9937\9937515a\03\#03-LTR.doc

cc: Koerner, BAR
Halladay, BAR
EPA
NPS
SD

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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NOV 12 1999

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for U.S. Sugar Corporation
Clewiston Mill located in Clewiston, Florida PSD-FL-272

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft PSD permit for U.S. Sugar Corporation - Clewiston Mill dated October 4, 1999. The draft PSD permit is for the increase in operations of the sugar refinery and Boiler No. 4. The proposed facility modifications include the addition of 3 conditioning silos and a sugar/starch bin, the increase in hours of operation of 3 existing vacuum systems and the VHP dryer, and the increase in operation of Boiler No. 4. The boiler currently combusts bagasse as its primary fuel and fires No. 6 fuel oil as its backup fuel. The existing permit limits fuel oil combustion to 500,000 gallons/year. U.S. Sugar proposes to increase the operation of Boiler No. 4 from 2.7133×10^{12} Btu/yr (160 days/yr) to 2.88×10^{12} Btu/yr (200 days/yr). Total emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC) and particulate matter (PM/PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we have the following comments regarding operational and emission limits in the draft PSD permit.

1. Section III, Conditions 2 and 3, do not limit the hours of operation of the boiler, but do limit the heat input of the boiler to 2,880,000 mmBtu/yr during any consecutive 12 months. When the boiler is firing bagasse with a maximum of 600 mmBtu/hr (24-hour average), this is equivalent to operating 4800 hours per year at maximum capacity. However, if the boiler is firing bagasse and fuel oil together, the maximum heat input is only 530 mmBtu/hr. This heat input is obtained from the maximum limit of 300,000 lb/hour of steam (i.e., fuel oil limit of 1500 gallons/hour and 42.5 tons/hour of bagasse). Given that there is no permit limit on the actual number of operating hours per year or on the annual usage of fuel oil, the worst case scenario for emissions would be firing a combination of fuel oil and bagasse for up to 2,880,000 mmBtu/year, which is equivalent to 5434 hours/year. The modeling and BACT analysis should reflect this worst case scenario, or the permit should be modified to include

an annual operating limit of 4800 hours per year (which does not restrict the number of days/year the boiler can operate).

2. Section III, Condition 6, proposes to allow excess emissions of the granular carbon regeneration furnace (GCRF) during startup for up to 2 hours in any 24-hour period. It is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

3. As mentioned in our previous comment letter (dated September 20, 1999), EPA believes the SO_2 limit of 0.1 lb/mmBtu when burning bagasse in Boiler No. 4 exceeds a reasonable margin for compliance, and we ask the Florida Department of Environmental Protection (FDEP) to reconsider this limit.

In terms of the air quality impact assessment associated with the PSD permit application, and the October 1999 Technical Evaluation, Preliminary Determination, and Intent to Issue Construction Permit, the following should be noted:

1. ISC-PRIME Model - The air quality impact assessment provided in U.S. Sugar Corporation's PSD permit application was based on the ISC-PRIME model. Although the October 1999 preliminary determination and draft PSD permit were based on the use of the guideline ISCST3 model, the draft PSD permit indicates the non-guideline ISC-PRIME dispersion and transport model will be controlling if approved within 180 days of issuance of the final permit. EPA's November 4, 1999, letter to FDEP approved the use of the ISC-PRIME model for the U.S. Sugar Corporation - Clewiston Mill PSD permit application. Therefore, the ISCST3 model impact assessment provided as the basis for the preliminary determination and draft PSD permit is not appropriate nor applicable for this permitting action.

2. Air Quality Impact Assessment - Because only ISC-PRIME modeled air quality impact assessments are applicable to the U.S. Sugar Corporation Clewston facility, the ISCST3 modeling provided as the basis for the preliminary determination and draft PSD permit were not reviewed. EPA has reviewed the ISC-PRIME modeling results provided in the PSD permit application and has provided concerns and comments to both Golder Associates and FDEP. It is our understanding that Golder Associates is currently performing revised ISC-PRIME modeling that incorporates our comments and takes into account the mix of percent sulfur fuel oil and/or stack height adjustments to meet NAAQS. Therefore, EPA's comments on the appropriate impact assessment can not be provided at this time. Our review comments can only be provided subsequent to receipt and review of U.S. Sugar Corporation's revised modeling results.

Based on the above discussion, EPA requests that the final permit be issued only after EPA and FDEP have reviewed and concur on the final facility design and air quality impact assessment.

Thank you for the opportunity to comment on the U.S. Sugar - Clewiston Mill preliminary determination and draft PSD permit. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Stan Krivo at 404-562-9123.

Sincerely,

Greg M. Worley

for R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

CC: Jeff Koerner, BAR
SD
NPS
D. Buff, Golder Assoc.

Golder Associates Fax

To: Jeffery Koerner, P. E. **Fax Number:** 850-922-6979

Company: FDEP **Date:** September 29, 1999

From: David Buff **e-mail:** @golder.com

Our ref: 9937515A/3 **Voice Mail:**

RE:

Total pages (including cover): 3 **Hard copy to follow** ☐

MESSAGE

Golder Associates

6241 NW 23rd St., Suite 500
Gainesville, FL 32653
U.S.A.
Telephone: (352) 336-5600
Fax: (352) 336-6603

Comprehensive Consulting Services in Geotechnical Engineering, Environmental Remediation and Waste Management

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Golder Associates Inc.

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

September 29, 1999 9937515A/3

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL 32399

Attention: Jeffery Koerner, P.E.

RE: United States Sugar Corporation (U.S. Sugar)
PSD Permit Application for Boiler No. 4 and the Sugar Refinery at the Clewiston Mill
Information Submittal No. 4

Dear Mr. Koerner:

Based on my conversations this week with Cleve Holladay regarding U.S. Sugar's PSD permit application to modify operation of Boiler No. 4 and expand the sugar refinery operation, a few additional questions have been raised. The purpose of this letter is to respond to these questions. The questions and our response is provided below.

1. In regards to Section 4.0 of the PSD report, the question was raised concerning the background ambient concentration selected for carbon monoxide (CO). In Section 4.2.3 of the PSD report, it was stated that West Palm Beach CO monitoring data was not considered to be representative of the Clewiston area due to the distance from Clewiston to West Palm Beach, and also because of the significant mobile traffic in West Palm Beach compared to Clewiston. The West Palm Beach data was then used for the CO background concentration. Of the three CO monitoring stations operating in 1997, the station with the lowest second-highest 1-hour and 8-hour CO concentration was used.

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In summary, no significant impacts due to associated growth are expected due to the proposed project.

3. In regards to a description of vegetation and soils in the vicinity of the Clewiston mill, a description was provided on page 7-1 of the application.

Thank you for consideration of this information. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/arz

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
of National Park Service

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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Mr. A. A. Linero, P.E.
Administrator/New Source Review Section
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

PSD-FL-272

SUBJ: Use of ISC-PRIME
PSD Permit Application
U.S. Sugar Corporation Clewiston Mill
Clewiston, Florida

Dear Mr. Linero:

Thank you for providing the Prevention of Significant Deterioration (PSD) permit application for the U.S. Sugar Corporation - Clewiston Mill, dated June 1999. This application requests an increase in the operation of the sugar refinery and Boiler No. 4. Our review comments excluding the air quality impact assessment were provided in our September 20, 1999, letter. The purpose of this letter is to provide our evaluation of the appropriateness of the use of the none-guideline ISC-PRIME dispersion and transport model for the ambient air impact assessments resulting from the proposed Clewiston Mill modifications.

The justification for the use of the non-guideline model [i.e., model not recommended in the United States Environmental Protection Agency's (EPA) Guideline on Air Quality Models (40 C.F.R. 51, Appendix W)] was provided in the U.S. Sugar Clewiston Mill PSD permit application. This justification, combined with available articles and documents on the development and performance of the ISC-PRIME model, were the basis of our review and evaluation.

The reviewed articles and development documents reported ISC-PRIME to perform as well as or better than ISCST3 when predicted maximum concentrations are compared to observed measurements. ISC-PRIME was also found not to be significantly biased toward under-estimation of maximum concentrations. A summary of our case-by-case evaluation of ISC-PRIME for the U.S. Sugar Clewiston application is provided as an attachment.

Based on our evaluation of ISC-PRIME, EPA concurs with the use of this model for the Clewiston Mill air impact assessment. In accordance with EPA's division of responsibility with respect to non-guideline model approval, this EPA Region 4 case-by-case approval for the U.S.

Sugar Clewiston application is not an endorsement for use by any other source. EPA's Office of Air Quality Planning and Standards (OAQPS) is currently considering a generic approval of ISC-PRIME. If generically approved, ISC-PRIME may become a guideline model for general application.

It should be noted that any public notice of this project must include the fact that the air quality impact assessment was performed using a case-specific approved non-guideline ISC-PRIME model. The public must be provided an opportunity to comment and have a public hearing on this matter.

Thank you again for the opportunity to review and comment on this PSD application. If you have any questions, or if we can be of further assistance, please contact Mr. Stan Krivo of the EPA Region 4 staff at (404) 562-9123.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

Attachment

cc: Joseph A. Tikuart, EPA/OAQPS
Cleve Holladay, FDEP
Tom Rogers, FDEP
CC: SD
NPS
D. Buff, Golder Assoc

Evaluation of ISC-PRIME For Application To
U.S. Sugar Corporation Clewiston Mill
Air Quality Impact Assessment

Introduction

The Florida Department of Environmental Protection (FDEP) has reviewed the Prevention of Significant Deterioration (PSD) permit application for a modification of U.S. Sugar Corporation (U.S. Sugar) Clewiston Mill. One of FDEP's concerns is the application of the non-guideline ISC-PRIME dispersion and transport model to the ambient air quality assessment. The use of the guideline ISCST3 dispersion and transport model for the U.S. Sugar Clewiston Mill emission sources reveals very large predicted SO_2 and PM10 concentrations at the site boundary - concentrations that exceed the PM10 and SO_2 National Ambient Air Quality Standards (NAAQS). Use of the ISC-PRIME model with the same input emission and receptor values also predicts large concentrations, but none that exceed the applicable PSD increments nor NAAQS.

The ISC-PRIME model has been submitted to the United State Environmental Protection Agency's (EPA) Office of Air Quality Planning and Standards (OAQPS) for consideration as a guideline model. OAQPS have reviewed and tested this model. It was also reviewed at the 1998 Regional/State/Local Agency Modelers Workshop. With a few restrictions, the Workshop participants recommended ISC-PRIME be included as a guideline air quality model in the next revision to the Guideline on Air Quality Models (GAQM).

Although OAQPS may propose ISC-PRIME for inclusion as a guideline model, this has not officially been proposed and public comment has not been solicited. Therefore, ISC-PRIME remains a non-guideline model that must be evaluated and approved for application on a case-by-case basis. The U.S. Sugar PSD application is the first time the ISC-PRIME model has been used in a regulatory application in EPA Region 4. The following is a summary of EPA Region 4's review of U.S. Sugar's justification of the appropriateness of ISC-PRIME for the assessment of ambient air impacts.

Reviewed Documents - ISC-Prime and U.S. Sugar Corporation

The following documents were reviewed in the case-by-case justification for the use of the non-guideline ISC-PRIME dispersion and transport model for the PSD air quality impact assessment of planned modifications of the U.S. Sugar Clewiston, Florida facility.

1. Hastings, Janis; "Review of the ISC-PRIME model, GVEA Healy Power Plant Air Quality Control No. X049"; Letter from U.S. Environmental Protection Agency Region 10 to Alaska Department of Environmental Conservation; April 29, 1998.

2. Paine, Robert J., and Frances Lew; "Project Prime: Evaluation of Building Downwash Models Using Field and Wind Tunnel Data"; Undated article and presentation slides developed by ENSR Corporation for Electric Power Research Institute (EPRI) Project RP 3527-02.

3. Paine, Robert J., and Frances Lew; "Results of the Independent Evaluation of ISCST3 and ISC-PRIME"; Final Report; Electric Power Research Institute; November 1997.

4. Shulman, Loyd L., David G. Strimaitis, and Joseph S. Scire; "Development and Evaluation of the Prime Plume Rise and Building Downwash Model"; Undated draft journal article by Earth Tech, Concord, MA.

5. Staff Report; "Consequences Analysis of Using ISC-PRIME Over the Industrial Source Complex Short Term Model"(Draft); U.S. Environmental Protection Agency; April 1998.

6. U.S. Sugar Corporation; "Information Submittal No. 3 - PSD Permit Application for Boiler No. 4 and the Sugar Refinery at the Clewiston Mill"; 13 September 1999.

7. U.S. Sugar Corporation; "PSD Permit Application for United States Sugar Corporation Clewiston Boiler No. 4 and Sugar Refinery," prepared by Golder Associates Inc.; June 1999.

Basis of Evaluation

The evaluation criteria for a case-by-case approval of an alternate or non-guideline model are given in Section 3.2 of 40 CFR Part 51, Appendix W - Guideline on Air Quality Models (GAQM). Section 3.2 presents three separate conditions under which an alternate model can be approved. The second condition is the basis for the justification of ISC-PRIME (i.e., statistical performance evaluation using measured air quality data results in the alternate model having better performance than a comparable guideline model). The issues addressed in Region 4's evaluation of the appropriateness and applicability of ISC-PRIME for the U.S. Sugar application include:

- Technical appropriateness of the model for the application.
- Appropriate data bases available to perform the modeling analysis.
- Model performance evaluations appropriate to U.S. Sugar and demonstrate no bias toward underestimates of concentrations.
- Better model performance when compared to reference guideline model.

Technical Consideration

The ISC-PRIME model was developed to improve the downwash algorithms of the ISCST3 regulatory guideline model. Two important shortcomings of the ISCST3 downwash treatment

are the inability to predict concentrations in the building cavity (near wake) and to assess the affects of stack location relative to the influencing downwash structure. In addition, the downwash routines of ISCST3 were developed largely from ambient data representing neutral stability, moderate-to-high wind speeds, and winds perpendicular to the building face, with non- or low-buoyant plumes. These limitations were addressed in the development of ISC-PRIME.

Of major concern at the Clewiston Mill are emissions from the boiler stacks. These stacks are located between three and five building lengths from the buildings controlling downwash. Although EPA studies of the effects of building downwash within wakes show reduction as the stack's distance from the controlling building is increased, ISCST3 uses the full downwash effects independent of stack location in the wake region. Thus, ISCST3 modeling of the Clewiston emissions may produce less realistic estimates of wake dispersion than ISC-PRIME. Ambient concentrations from these two models for the Clewiston facility show ISC-PRIME with smaller concentrations in the wake region.

In terms of the basis of the downwash algorithms in the ISCST3 and ISC-PRIME models, both models' algorithm are semi-empirical. The empirical data used for ISC-PRIME were largely from an extensive series of USEPA performed wind tunnel experiments in 1992 and 1993. The ISCST3 downwash algorithms pre-date these experiments. Because ISC-PRIME is based on more extensive wind tunnel data sets, it has a stronger technical base than ISCST3.

On a theoretical basis, ISC-PRIME uses the conservation equations of mass, momentum, and energy. This model accounts for the streamline ascent over structure and decent in the wake region. Also the wind shear effects about and downwind of structures are accounted for in ISC-PRIME. Therefore, the theoretical basis of ISC-PRIME is technically more sophisticated than ISCST3 and may provide more realistic estimates of plume rise, dispersion, and transport conditions in the wake region - a condition applicable to the Clewiston application.

In terms of the data needed to run ISC-PRIME, the input data requirements are the same as ISCST3 with the exception of building and stack configurations and dimensions. Similar to the BPIP program providing building information for running ISCST3, a supplementary program BPIPPRM has been developed to provide the needed building information for the running of ISC-PRIME. Therefore, adequate input data exists to perform ISC-PRIME model analysis for U.S. Sugar Clewiston.

Data Bases For Model Development And Performance

The data bases used in the development of ISC-PRIME included wind tunnel studies, numerical model results, and both short-term tracer and long-term field measurement programs. An independent evaluation of the completed model was performed by an EPRI contractor using four data bases. This was an independent evaluation as it was: 1) Conducted by a contractor not involved with model development; and 2) Data bases used in evaluation were not used in the

model development. A number of performance measures were considered and statistical tests performed to determine the significance of the performance differences observed. Thus, adequate data bases exist for both the development and evaluation of model performance.

Performance Evaluations

Comparison With Data Bases

In the assessment of ISC-PRIME model performance, meteorological conditions that produce the highest ground-level concentrations were used (e.g., near-neutral stability and moderate to high wind speeds). Comparsion of both ISCST3 and ISC-PRIME predicted concentrations against the independent data bases show that for these downwash producing meteorological conditions, the two models performances were comparable, with ISC-PRIME performing slightly better (i.e., better agreement with observations) than ISCST3.

Site specific data from the Clewiston facility site would provide the most relevant basis for model performance evaluation. These data were not available so a review of the similarity of the emissions, plant configuration, and receptor conditions used in the ISC-PRIME model evaluation was performed to determine the applicability of the evaluation to the Clewiston application. Of the evaluation data bases used, the Bowline Point and the Lee Power Plant data were the most similar to the boilers at the Clewiston facility in terms of stack heights (87 and 65 meters respectively) and stack to building ratios (1.3 and 1.5 respectively). The buoyant and momentum fluxes for these power plants are expected to be representative of those at Clewiston. Although the evaluation and development data bases were not obtained under the same plant configuration as U.S. Sugar Clewiston, they are believed to relevant and representative of the U.S. Sugar Clewiston.

Comparison With Reference Model

The performance evaluation comparisons of the ISC-PRIME and ISCST3 models demonstrated ISC-PRIME with generally as well or better agreement with observed maximum concentrations during downwash conditions. ISC-PRIME did not demonstrate a bias toward under predictions. Thus, an independent evaluation demonstrated ISC-PRIME with an overall performance as good as, or better than, ISCST3 in downwash conditions.

EPA performed its own consequence analysis of the ISC-PRIME software and EPRI reports. This consisted of verifying that ISCST3 and ISC-PRIME produced the same results when no building dimensions were included, confirming the independent modeling results, and determining the consequences of using ISC-PRIME for building downwash applications.

- The consequence analysis showed that both models produced the same results when run without building input data. The PRIME downwash algorithms do not interfere with the

proper operation of the model under no downwash conditions.

- The three field studies used in the EPRI independent evaluation showed ISC-PRIME tends to be less conservative than ISCST3 but more conservative (i.e., produces larger concentrations) than the observed values.

- For cavity analyses, output differences between ISCST3 and ISC-PRIME were dependent on stack location, stack to building height ratios, urban/rural setting, and downwind distances. ISC-PRIME and ISCST3 converge on common concentrations beyond 1 km and are the same beyond 10 km.

In summary, ISC-PRIME provides overall conservative estimates of concentrations that are more realistic than those provided by ISCST3.

Conclusion and Recommendation

Based on the application of Section 3.2 of 40 CFR Part 51, Appendix W (Guideline on Air Quality Models) for the evaluation of the use of an alternate model, ISC-PRIME appears appropriate and applicable for the U.S. Sugar Clewiston air quality impact assessment. ISC-PRIME appears to be technically better than ISCST3 and is better at predicting maximum concentrations during downwash conditions. In terms of application to the U.S. Sugar Clewiston facility, it appears that ISC-PRIME would provide a more realistic but conservative estimate of the maximum downwash concentrations from this facility, while also providing concentrations equal to ISCST3 predictions beyond the wake region. Therefore, ISC-PRIME is considered applicable and appropriate for application to the air quality impact assessment for the U.S. Sugar Company's Clewiston Mill.

EPA United States of America
Environmental Protection Agency

A FAX FROM Region 4

TO:	FAX NO:
AL LiNERO Jeff KoERDER FDEP	850-922-6979

SUBJECT:

FROM:	PHONE NO:
Jim Little / Katy Forney	(404) 562-9118 / 9130
OFFICE: APTMD	FAX NO. FOR: (404) 562-9095

COMMENTS:

U.S. Sugar Corp. - Clewiston Mill

DATE	NO. OF PAGES
11-12-99	4 (including cover sheet)

EPA FAX FORM (E-Forms 4.3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

NOV 12 1999

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for U.S. Sugar Corporation Clewiston Mill located in Clewiston, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft PSD permit for U.S. Sugar Corporation - Clewiston Mill dated October 4, 1999. The draft PSD permit is for the increase in operations of the sugar refinery and Boiler No. 4. The proposed facility modifications include the addition of 3 conditioning silos and a sugar/starch bin, the increase in hours of operation of 3 existing vacuum systems and the VHP dryer, and the increase in operation of Boiler No. 4. The boiler currently combusts bagasse as its primary fuel and fires No. 6 fuel oil as its backup fuel. The existing permit limits fuel oil combustion to 500,000 gallons/year. U.S. Sugar proposes to increase the operation of Boiler No. 4 from 2.7133×10^{12} Btu/yr (160 days/yr) to 2.88×10^{12} Btu/yr (200 days/yr). Total emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC) and particulate matter (PM/PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we have the following comments regarding operational and emission limits in the draft PSD permit.

1. Section III, Conditions 2 and 3, do not limit the hours of operation of the boiler, but do limit the heat input of the boiler to 2,880,000 mmBtu/yr during any consecutive 12 months. When the boiler is firing bagasse with a maximum of 600 mmBtu/hr (24-hour average), this is equivalent to operating 4800 hours per year at maximum capacity. However, if the boiler is firing bagasse and fuel oil together, the maximum heat input is only 530 mmBtu/hr. This heat input is obtained from the maximum limit of 300,000 lb/hour of steam (i.e., fuel oil limit of 1500 gallons/hour and 42.5 tons/hour of bagasse). Given that there is no permit limit on the actual number of operating hours per year or on the annual usage of fuel oil, the worst case scenario for emissions would be firing a combination of fuel oil and bagasse for up to 2,880,000 mmBtu/year, which is equivalent to 5434 hours/year. The modeling and BACT analysis should reflect this worst case scenario, or the permit should be modified to include

an annual operating limit of 4800 hours per year (which does not restrict the number of days/year the boiler can operate).

2. Section III, Condition 6, proposes to allow excess emissions of the granular carbon regeneration furnace (GCRF) during startup for up to 2 hours in any 24-hour period. It is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

3. As mentioned in our previous comment letter (dated September 20, 1999), EPA believes the SO_2 limit of 0.1 lb/mmBtu when burning bagasse in Boiler No. 4 exceeds a reasonable margin for compliance, and we ask the Florida Department of Environmental Protection (FDEP) to reconsider this limit.

In terms of the air quality impact assessment associated with the PSD permit application, and the October 1999 Technical Evaluation, Preliminary Determination, and Intent to Issue Construction Permit, the following should be noted:

1. ISC-PRIME Model - The air quality impact assessment provided in U.S. Sugar Corporation's PSD permit application was based on the ISC-PRIME model. Although the October 1999 preliminary determination and draft PSD permit were based on the use of the guideline ISCST3 model, the draft PSD permit indicates the non-guideline ISC-PRIME dispersion and transport model will be controlling if approved within 180 days of issuance of the final permit. EPA's November 4, 1999, letter to FDEP approved the use of the ISC-PRIME model for the U.S. Sugar Corporation - Clewiston Mill PSD permit application. Therefore, the ISCST3 model impact assessment provided as the basis for the preliminary determination and draft PSD permit is not appropriate nor applicable for this permitting action.

2. Air Quality Impact Assessment - Because only ISC-PRIME modeled air quality impact assessments are applicable to the U.S. Sugar Corporation Clewston facility, the ISCST3 modeling provided as the basis for the preliminary determination and draft PSD permit were not reviewed. EPA has reviewed the ISC-PRIME modeling results provided in the PSD permit application and has provided concerns and comments to both Golder Associates and FDEP. It is our understanding that Golder Associates is currently performing revised ISC-PRIME modeling that incorporates our comments and takes into account the mix of percent sulfur fuel oil and/or stack height adjustments to meet NAAQS. Therefore, EPA's comments on the appropriate impact assessment can not be provided at this time. Our review comments can only be provided subsequent to receipt and review of U.S. Sugar Corporation's revised modeling results.

Based on the above discussion, EPA requests that the final permit be issued only after EPA and FDEP have reviewed and concur on the final facility design and air quality impact assessment.

Thank you for the opportunity to comment on the U.S. Sugar - Clewiston Mill preliminary determination and draft PSD permit. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Stan Krivo at 404-562-9123.

Sincerely,

for R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

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Recipient's Name (Please Print Clearly) (to be completed by mailer)
Mr. William A. Raiola, VP

Street, Apt. No., or PO Box No.
111 Ponce DeLeon Ave.

City, State, ZIP+4
Clewiston, FL 33440

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Mr. William A. Raiola, V.P.
United States Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

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William A. Raiola, VP
United States Sugar Corporation
111 Ponce DeLeon Ave.
Clewiston, FL 33440

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X Andrea Solis ☐ Agent ☐ Addressee

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Bureau of Air Regulation, NSR
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Tallahassee, FL 32399-2400

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MAR 14 2001
BUREAU OF AIR REGULATION

The Clewiston News

Published Weekly — Clewiston, Florida

AFFIDAVIT OF PUBLICATION

State of Florida
County of Hendry

Before the undersigned authority, personally appeared Katrina Elsken, who on oath says she is the Executive Editor of the Clewiston News, a weekly newspaper published at Clewiston in Hendry County, Florida, that the attached copy of advertisement, being a

Public Notice in

the matter of Intent to Issue Air Construction Permit. DEP File No. 051003-010-AC Permit No. PSD-FL-272A in the

court, was published in

said newspaper in the issues of December 27, 2000

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

Katrina Elsken

Sworn to and subscribed before me this 27th day of December, A.D. 20 00.

Tiffany Koon

Notary Public

TIFFANY KOON
Notary Public - State of Florida
My Commission Expires Jun 25, 2004
Commission # CC948508

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PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 051003-010-AC
Permit NO. PSD-FL-272A

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 project restores authorization to fire fuel oil containing up to 2.5% sulfur by weight. This authorization was lost in original Permit No. PSD-FL-272 because the supporting Air Quality Analysis was based on increased stack heights and a lower fuel sulfur content for Boiler Nos. 1-3. During the summer, the stacks for Boiler Nos. 1-3 were raised to 213 feet in height. A revised Air Quality Analysis was performed based on the ISC PRIME dispersion model, taller stacks, and higher fuel sulfur content. The ISC PRIME model was used to better evaluate the contributions associated with stack downwash from the refinery building. Although the ISC PRIME model is a non-guideline model, it has been proposed by EPA as a replacement for ISCST3 and was approved by EPA Region 4 for use with this project. While the revised Air Quality Analysis demonstrates compliance with the Ambient Air Quality Standards and PSD increments, it included several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. Theses constraints are included as conditions in the Draft Permit. Because the original PSD permit allowed the permittee to regain use of the higher sulfur fuel, a determination of Best Available Control Technology (BACT) was not required.

An air quality impact analysis was conducted for the project. Emissions from the modified facility 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 NO_2, SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment	Consumed (ug/m³)	Allowable Increment (ug/m³)	Percent Increment Consumed
PM_{10}			
24-hour	26	31	84%
Annual	1	17	6%
SO_2			
3-hour	357	512	70%
24-hour	75	91	82%
Annual	13	20	65%
NOx			
Annual	4	25	16%

NO_2 and PM_{10} emissions from the project have no significant impact on the PSD Class I Everglades National Park. The maximum predicted PSD Class I SO2 increments consumed in the Everglades National Park by all sources in the area, including this project, will be as follows:

PSD Class II Increment	Consumed (ug/m³)	Allowable Increment (ug/m³)	Percent Increment Consumed
SO_2			
3-hour	20	25	80%
24-hour	3	5	60%
Annual	0.33	2	7%

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 Rd, 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 petitions 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.

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JAN 04 2001

BUREAU OF AIR REGULATION

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 specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statues 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.

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	Department of Environmental Protection
Bureau of Air Regulation	South Florida District Office
Suite 4, 111 S. Magnolia Drive	Suite 364, 2295 Victoria Avenue
Tallahassee, Florida, 32301	Fort Myers, Florida, 33901-3381
Telephone: 850-488-0114	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.

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Mr. Murray T. Brinson

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111 Ponce DeLeon Ave.
City, State, ZIP+4
Clewiston, FL 33440

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Mr. Murray T. Brinson
Vice President
United State Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

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C. Signature
X Andrew Salis ☐ Agent ☐ Addressee

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Recipient's Name (Please Print Clearly) (To be completed by mailer)
Mr. Marray T Brinson, Vice President
Street, Apt. No.; or PO Box No.
United States Sugar Corp 111 Ponce De Leon Ave
City, State, ZIP+4
Clewiston, FL 33440

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1. Article Addressed to:

Mr. Murray T. Brinson
Vice President
United States Sugar Corp.
111 Ponce De Leon Ave
Clewiston, FL 33440

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A. Received by *(Please Print Clearly)* B. Date of Delivery 10/13/00

C. Signature
X Andrea Rolls ☐ Agent ☐ Addressee

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Bureau of Air Regulation, NSRS
2600 Blair Stone Rd MS 5505
Tallahassee, FL 32399-2400

RECEIVED
OCT 17 2000
BUREAU OF AIR REGULATION

32399+2400

Z 031 392 009

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Bunson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston FL	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-22-99	

PS Form **3800**, April 1995

0510003-009-AC
PSD-FI-272

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Murray Bunson, VP
US Sugar Corp
111 Ponce de Leon Ave
Clewiston, FL
33440

4a. Article Number Z 031 392 009

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 11.24.99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Andrea Sales

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED

NOV 30 1999

BUREAU OF AIR REGULATION

Z 031 392 013

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Murray Burson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 0510003-009-AC 10-6-99 050-FI-272	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Murray J. Burson
US Sugar Corp
111 Ponce De Leon Ave
Clewiston, Fl
33440

4a. Article Number
Z 031 392 013

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
10-8-99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Andrea Solis

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

UNITED STATES POSTAL SERVICE

RECEIVED

OCT 12 1999

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

BUREAU OF AIR REGULATION

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

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 powered 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 bagass/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 decolonization process in the refinery operations includes a carbon bed to remove colorant and organic from the gas stream. Particulate matter is controlled by a wet venture/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 and air quality analysis based on an air dispersion model (SC-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 and 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 SO2, and PM10 consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment Consumed (ug/m3)		Allowable Increment (ug/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 SO2 in the Everglades National Park, consumed by all sources in the area, including this project, will be as follows:

PSD Class *I* Increment Consumed (ug/m3)		Allowable Increment (ug/m3)	Percent Increment Consumed
SO2			
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 fro 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 fro 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 thus 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 on 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 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 28106.205 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.

A complete project file is available for public inspection during normal business hours, 8 :a.m. to 5 :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) 488-1143

Department of Environmental Protection
South Florida District Office
Suite 264, 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 (805) 488-0114, for additional information.

The Clewiston News

Published Weekly Clewiston, Florida

AFFIDAVIT OF PUBLICATION

State of Florida
County of Hendry

Before the undersigned authority, personally appeared Tracy Whirls, who on oath says she is the Managing Editor of the Clewiston News, a weekly newspaper published at Clewiston in Hendry County, Florida, that the attached copy of advertisement, being a Notice in

the matter of Intent

in the

court, was published in

said newspaper in the issues of

October 13, 1999

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

Tracy Whirls

Sworn to and subscribed before me this 13th day

of October, A.D. 19 99.

B K Christiansen

Notary Public

B. K. CHRISTIANSEN
MY COMMISSION # CC 640756
EXPIRES: June 27, 2001
Bonded Thru Notary Public Underwriters

Lyons Printing

RECEIVED
OCT 19 1999
BUREAU OF AIR REGULATION

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Jeffery Koerner

2.

3.

5.

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE _____

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

X FOR YOUR FILES

COMMENTS:

Tallahassee office/ DEP Air Program Mail Station 5505

NOTE: THIS WAS LOST IN OUR MAIL SYSTEM. IT WAS RECEIVED BY FAX ON 8-30-99. JPK

FROM: WBSED DATE: 12/23/99 PHONE: 922-6259

DEP 15-026 (12/93)

Nancy

Z 333 618 126

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Murray Bunison	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston FL	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 8-18-99	
051003-009-AC PSD-FI-272	

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Murray J. Bunison, VP
US Sugar Corp
111 Ponce DeLeon Ave
Clewiston, FL 33440

4a. Article Number
Z 333 618 126

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 8.20.99

5 Received By *(Print Name)*

8 Addressee's Address *(Only if requested and fee is paid)*

6 Sign

X

PS For ceipt

Thank you for using Return Receipt Service.

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
AUG 23 1999
BUREAU OF AIR REGULATION

P 265 657 758

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Mr. Murray T. Brinson, Vice Pres.
United States Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	7-22-99 Sgk

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. Murray T. Brinson, Vice Pres.
United States Sugar Corp.
111 Ponce DeLeon Ave.
Clewiston, FL 33440

4a. Article Number
P 265 657 758

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
7-26-99 BJ

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Andrea Sallis

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR RESOURCES MANAGEMENT
BUREAU OF AIR REGULATION - TITLE V
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400
MS 5505

RECEIVED
JUL 28 1999
BUREAU OF AIR REGULATION

Z 341 355 318

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray T Brinson, VP.	
Street & Number 111 Ponce De Leon Ave	
Post Office, State, & ZIP Code Clewiston, FL 33440	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 6/21/00	

PS Form **3800**, April 1995

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Murray T. Brinson, VP.
United States Sugar Corp.
111 Ponce De Leon Ave.
Clewiston, FL 33440

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* | B. Date of Delivery 6/23/00

C. Signature
X [signature] ☐ Agent ☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
Z 341 355 318

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSR
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
JUN 26 2000
BUREAU OF AIR REGULATION

Z 341 355 297

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Brinson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston FL	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-25-00	

PS Form **3800**, April 1995

0510003-010-AC
PSD-FI-272A

Fold at line over top of envelope to the right of the return address

SENDER: *COMPL...* ...ON ON DELIVERY

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1 Article Addressed to:
Mr. Murray D. Brinson
U.S. Sugar Corp.
111 Ponce DeLeon Ave
Clewiston, Florida
33440

A. Received by *(Please Print Clearly)* | B. Date of Delivery 5-30-00

C. Signature
X Andrea Solis ☐ Agent ☐ Addressee

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

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

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

2 Article Number *(Copy from service label)* Z 341 355 297

PS Form **3811**, July 1999 Domestic Return Receipt 102595-99-M-1789

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
JUN 01 2000
BUREAU OF AIR REGULATION

Z 031 391 933

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Burison	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 2-7-00	

PS Form **3800**, April 1995

0510003-01D-AC

CERTIFIED

Fold at line over top of envelope to the right of the return address

SENDER:
- Complete ite
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Murray J. Burison
U.S. Sugar Corp.
111 Ponce De Leon Ave
Clewiston, Fl
33440

4a. Article Number Z 031 391 933

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 2-9-00

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Andrea Sales

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

CERTIFIED

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
FEB 11 2000
BUREAU OF AIR REGULATION

01

Z 031 391 932

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Bunson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston FL	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 2-4-00	

PS Form **3800**, April 1995

0510003-010-AC
PSD-FI-272A

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
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I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Murray J. Bunson
US Sugar Corp
111 Ponce DeLeon Ave
Clewiston, FL 33440

4a. Article Number
Z 031 391 932

4b. Service Type
- ☐ Registered
- ☒ Certified
- ☐ Express Mail
- ☐ Insured
- ☐ Return Receipt for Merchandise
- ☐ COD

7. Date of Delivery
2-7-00

5. Received By: *(Print Name)*

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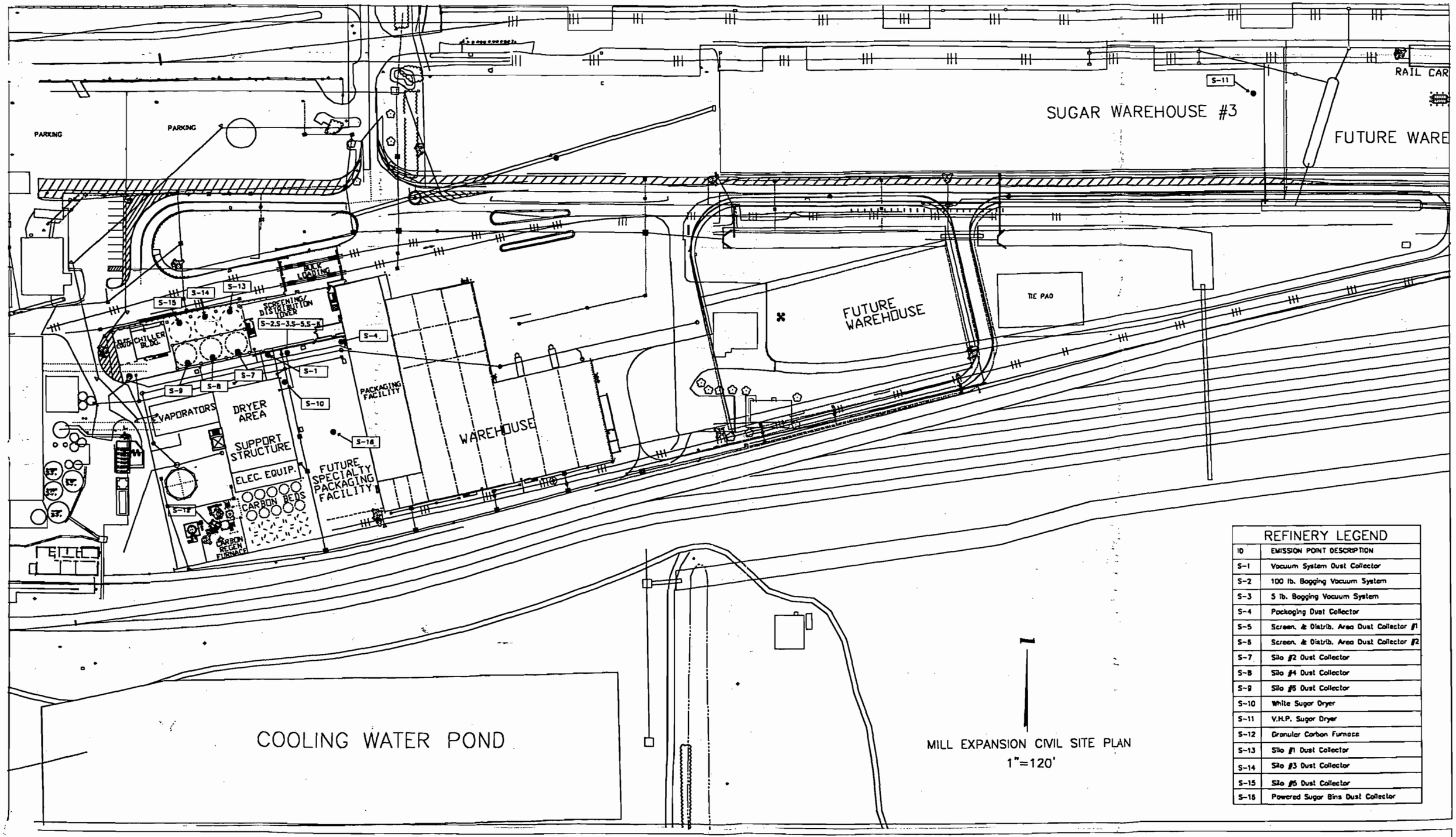
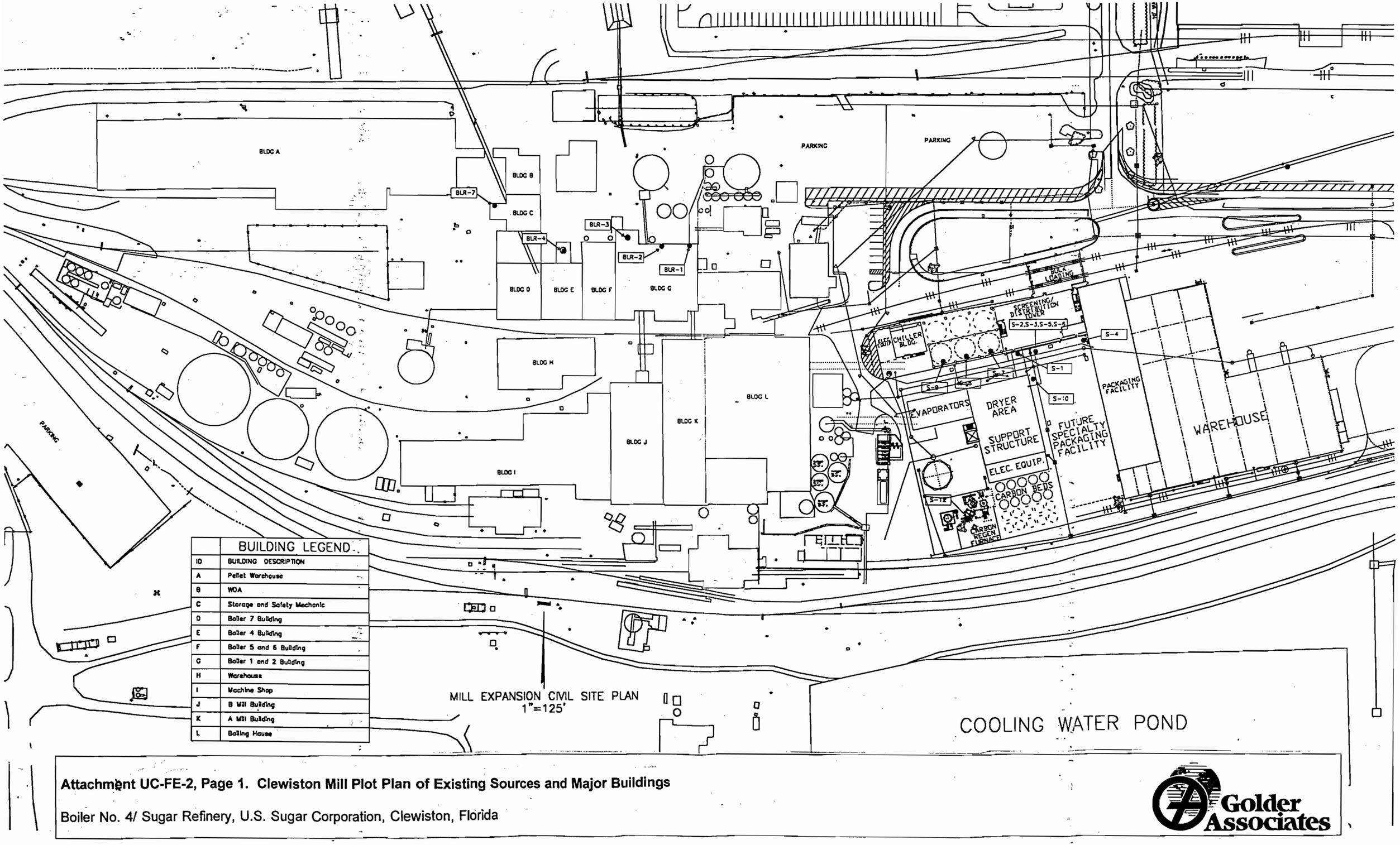


REFINERY LEGEND	
ID	EMISSION POINT DESCRIPTION
S-1	Vacuum System Dust Collector
S-2	100 lb. Bagging Vacuum System
S-3	5 lb. Bagging Vacuum System
S-4	Packaging Dust Collector
S-5	Screen. & Distrib. Area Dust Collector #1
S-6	Screen. & Distrib. Area Dust Collector #2
S-7	Silo #2 Dust Collector
S-8	Silo #4 Dust Collector
S-9	Silo #6 Dust Collector
S-10	White Sugar Dryer
S-11	V.H.P. Sugar Dryer
S-12	Granular Carbon Furnace
S-13	Silo #1 Dust Collector
S-14	Silo #3 Dust Collector
S-15	Silo #5 Dust Collector
S-16	Powered Sugar Bins Dust Collector

Attachment UC-FE-2, Page 2. Location of Sugar Refinery Sources and Major Buildings

Boiler No. 4/ Sugar Refinery, U.S. Sugar Corporation, Clewiston, Florida

Golder Associates



	BUILDING LEGEND
ID	BUILDING DESCRIPTION
A	Pellet Warehouse
B	WOA
C	Storage and Safety Mechanic
D	Boiler 7 Building
E	Boiler 4 Building
F	Boiler 5 and 6 Building
G	Boiler 1 and 2 Building
H	Warehouse
I	Machine Shop
J	B Mill Building
K	A Mill Building
L	Boiling House

MILL EXPANSION CIVIL SITE PLAN
1"=125'

Attachment UC-FE-2, Page 1. Clewiston Mill Plot Plan of Existing Sources and Major Buildings

Boiler No. 4/ Sugar Refinery, U.S. Sugar Corporation, Clewiston, Florida

Golder Associates

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

William A. Raiola, Vice President
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Air Permit No. 0510003-010-AC
PSD Permit No. PSD-FL-272A
Boiler No. 4 and Refinery Expansion
Palm Beach County, Florida

Enclosed is Final Permit No. 0510003-010-AC (PSD-FL-272A). This permit authorizes U.S. Sugar Corporation to complete the installation of emissions units associated with refinery operation and finalizes the changes related to the Boiler No. 4 and refinery expansion. As noted in the Final Determination (attached), minor changes to the draft permit were made by the Department, mostly at the request of the applicant. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

Duplicates

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/8/01 to the person(s) listed:

Mr. William A. Raiola, USSC*
Mr. Dave Buff, Golder Associates
Mr. Phil Barbaccia, South District Office – DEP
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Barbara J. Friday (Clerk) 3/8/01 (Date)

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on October 27, 2000 that modified operation of several Clewiston sugar mill boilers located at W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The applicant published the "Public Notice of Intent to Issue" in The Clewiston News on December 27, 2000 and the Department received proof of publication on January 4, 2001. During the 30-day comment period, the Department received comments only from the applicant. The following summarizes the Department's response to each comment and any resulting revision.

APPLICANT'S COMMENTS AND REQUESTS

The Department received written comments from the applicant on November 15, 2000 and January 30, 2001 requesting minor changes. Responses and revisions are summarized below.

Cover Letter and Placard Page

Request: The applicant notes that Mr. Brinson has retired from U. S. Sugar and that Mr. William A. Raiola, Vice President, is now the authorized representative for the Clewiston mill. *Response*: The permit will be revised.

Page 5 of 25

Request: 3. The applicant requests insertion of the word "net" after 1160 BTU in Footnote "b" of the table to clarify that this is the net BTU difference between the steam enthalpy and the feedwater enthalpy. *Response*: The clarification will be added.

Page 6 of 25

Request: 6. The applicant requests changing the word "the" to "a" to clarify that a tank different than the tank currently used could be utilized in the future. *Response*: The clarification will be added.

Request: 8. c. The applicant originally requested a lower scrubber flow rate based on previous compliance tests. The January 30th submittal withdrew this request. *Response*: No response required.

Page 8 of 25

Request: 15. In accordance with a recent Consent Order with the South District Office, the applicant requested a permit revision that required additional VOC testing and perhaps a new VOC limit based on the testing and application of good combustion practices. *Response*: The Consent Order is a stand-alone agreement. The applicant may request revised emissions standards based on additional testing as a permit modification. It would not be sufficient to simply demonstrate that a unit can no longer comply with permitted emissions standards. A test report was received during the processing of this Final Permit indicating that the unit is capable of complying with the current VOC standards. No revision made.

Page 9 of 25

Request: 17. and 18. The applicant notes that many of the PSD permit conditions have already been met, such as testing. *Response*: The Department notes the comment and is simply providing a full revision so that the PSD permit will be up-to-date. It is recognized that many of the requirements may have been completed. For example, no new "initial" tests are required as a result of this action. No revision was necessary.

Page 12 of 25

Request: 4. The applicant requested additional clarification to avoid burdensome record keeping and the deletion of steam production limits for Boiler Nos. 4 and 7 because they repetitive. *Response*: The Department

added the following statement to clarify, "The steam production chart records are sufficient to demonstrate compliance with these requirements." The limits will be retained because they specify critical parameters for the Air Quality Analysis, which was the basis of this permit modification.

Page 13 of 25

Request: 5. The applicant requested additional wording that would allow fuel oil with sulfur content of greater than 1.6%, if SO_2 testing when burning fuel oil demonstrates equivalent SO_2 emissions (due to removal of SO_2 in the boiler/scrubber system when burning fuel oil). The applicant also requests deletion of the fuel sulfur limits for Boiler Nos. 4 and 7 because they are repetitious and unnecessary. *Response*: At the appropriate time, the applicant may request changes to specific permit conditions through the modification process. The limits will be retained because they specify critical parameters for the Air Quality Analysis. No revision made.

Page 14 of 25

Request: 7.b(1). The applicant initially requested deletion of this condition. The January 30th submittal requested the wording be changed to, "Operation of Boiler No. 7 shall be operated to the greatest extent possible during the off-season, taking into account operating efficiency, steam demands, and boiler availability due to maintenance." *Response*: Unlike the existing sugar mill boilers, Boiler No. 7 was originally permitted to provide steam to the new refinery during the off-season. U.S. Sugar performed an Air Quality Analysis to demonstrate that operation of existing mill boilers during the off-season as backup units to Boiler No. 7 would not have any adverse impacts. To satisfy modeling requirements, the applicant requested a lower sulfur limit on fuel oil for the off-season and a cap on steam production rates. For these reasons, Condition 7.b.(1) was included. To satisfy the applicant's concerns (as agreed), the Department will clarify this condition to read, "During the off-season, Boiler No. 7 shall be operated as the primary unit to meet the steam demands of the refinery. As restricted by the conditions of this permit, other mill boilers may serve as backup units when Boiler No. 7 is down for maintenance, repair or during periods of unusually low steam demand."

Request: 10.a. The applicant expressed concern over calculating the "24-hour average" steam production rate based on actual hours rather than 24-hours. *Response*: The intent of this condition is to demonstrate compliance with Condition No. 7 of the same section. To clarify, the condition will be revised to, "For each 24-hour block of operation, the permittee shall record the total steam production rates (pounds, each) for Boiler Nos. 4 and 7 to demonstrate compliance with Condition No. 7 of this section. ~~The permittee shall calculate and record the 24-hour average steam production rate for these units based on the actual operating hours during the 24-hour period.~~"

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Request: 11. The applicant requests that this condition be clarified with the following change, "From this data, the permittee shall calculate and record the **combined** oil firing rates (gallons) for each 3-hour and each 24-hour block of ~~**combined**~~ operation for Boiler Nos. 1 – 4." *Response*: Clarification will be added.

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Request: 1,2. The applicant requests the condition to specifically identify that Subpart Kb applies only to EUs 024 and 026. *Response*: The Department will include the following sentence, "The following conditions apply to EUs 024 and 026:"

Request: 5. The applicant requests replacement of the word "facility" with the word "tank" at the end of this condition. *Response*: Permit will be revised.

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Request: 5. The applicant requests that the last four sentences of this condition (related to operations outside the specified range) be added to Condition No. 4 for the afterburner temperature of the GCRF. *Response*: The afterburner temperature is a "set" condition for the control equipment. The permit condition addresses short periods of operation below this level. This was not part of the modification under review. No revision made.

Request: 9. The applicant notes that certain conditions for the GCRF (such as testing) have already been met. *Response*: Again, the Department notes the comment and is simply providing a full revision so that the PSD permit will be up-to-date. It is recognized that many of the requirements may have been completed. For example, no new "initial" tests are required as a result of this action. No revision made.

Request: 11. The applicant requests rewording this condition to reflect the actual rule language, which describes production rates during compliance testing and provisions if testing is not performed within 90% of maximum. *Response*: Section III.G. of the permit does include the applicable rule language. The condition is clarifying that testing should be performed within 90% of the production capacity of the GCRF. No revision made.

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Request: The applicant notes that construction has been delayed for the three sugar silos (S-14, S-14, and S-15) and the powdered sugar/starch bins (S-16). All emissions units are small controlled sources of particulate matter totaling 1.33 TPY. A two-year extension is requested. *Response*: The Department specified an expiration date of December 31, 2002 to allow for the delayed construction. The project description was also revised to reflect remaining construction activities.

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Request: 6. The applicant notes that certain conditions for the particulate matter sources (such as testing) have already been met. *Response*: Again, the Department notes the comment and is simply providing a full revision so that the PSD permit will be up-to-date. It is recognized that many of the requirements may have been completed. For example, no new "initial" tests are required as a result of this action. No revision made.

OTHER CHANGES MADE BY THE DEPARTMENT

Page 1 of 25

During the processing of the Final Permit for this project, the applicant noted that vacuum pan No. 7 remained under construction. The original air construction permit issued in 1996 has an expiration date of October 25, 2001. Although vacuum pan No. 7 was purchased and received in 1997, it was not immediately installed due to a change in sugar market conditions. The applicant now intends to install this equipment and requests that this activity be clarified in the permit. Other than small amounts of isopropyl alcohol, no emissions are directly associated with this unit. The Department included installation of vacuum pan No. 7 in the project description on Page 1 with the remaining construction activities.

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During the processing of the Final Permit for this project, the applicant submitted CO and VOC test data, which was required by original Permit No. PSD-FL-272. Based on the test data and the applicant's proposal, the Department is required to reopen the PSD permit and establish process parameters for the flue gas oxygen content and CO concentration. The Department and applicant agreed to include such parameters into this final permit. On page 7, Specific Condition No. 9 was revised to include an alarm set point of 1.5% for the flue gas

oxygen content and 3000 ppm for the flue gas CO concentration, both based on a 1-hour block average. Minor revisions were also made to Appendix GCP (Good Combustion Practices).

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Section III.C., Description for Emissions Unit 025: Based on the latest response by the applicant, the Department corrected the volume of the storage tank serving Boiler Nos. 1-3 from 600,000 gallons to 400,000 gallons.

CONCLUSION

The Department considers the revisions to be minor. The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE

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

Authorized Representative:
William A. Raiola, Vice President

Permit No.	0510003-010-AC
PSD No.	PSD-FL-272A
Project:	Boiler No 4 and Refinery Expansion, Revised
SIC No.	2061, 2062
Expires:	December 31, 2002

PROJECT AND LOCATION

This permit authorizes the United States Sugar Corporation to modify operations at its existing sugar mill and refinery. Specifically, the permit allows increased operation of Boiler No. 4 and the existing refinery operation. The only new construction authorized by this permit the installation of three new sugar conditioning silos (emissions points S-14, S-14, and S-15 of EU 019), the installation of additional powdered sugar/starch silos (emissions point S-16 of EU-020), and the installation of vacuum pan No. 7. The revised permit includes new conditions that reflect the air quality analysis based on the ISC PRIME model.

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	Summary of Previous BACT Determination
Appendix GC	General Permit Conditions
Appendix GCP	Good Combustion Practices Plan

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 3/7/01

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 4 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

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
001	Bagasse Boiler No. 1 with wet scrubber (255,000 pounds of steam per hour)
002	Bagasse Boiler No. 2 with wet scrubber (230,000 pounds of steam per hour)
003	Bagasse Boiler No. 3 with wet scrubber (130,000 pounds of steam per hour)
004	Bagasse Boiler No. 5 (inactive, permanently shut down)
005	Bagasse Boiler No. 6 (inactive, permanently shut down)
009	Bagasse Boiler No. 4 with wet scrubber (300,000 pounds of steam per hour)
014	Bagasse Boiler No. 7 with electrostatic precipitator (385,000 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
025	Common fuel storage tank for Boiler Nos. 1 - 3
026	NSPS fuel storage tank for Boiler No. 7

Project No. 0510003-009-AC (Permit No. PSD-FL-272): For the original project, net emissions increases of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC were significant and the permit established emissions standards for these pollutants based on the Best Available Control Technology. Permit issuance was based on an Air Quality Analysis with ISCST3 modeling, increased stack heights for Boiler Nos. 1 – 3, and lower sulfur contents for Boiler Nos. 1 – 3. However, the permit allowed the facility to regain the higher sulfur content oil for use in Boiler Nos. 1 – 3 if a revised Air Quality Analysis demonstrated compliance with the AAQS and PSD increments.

Project No. 0510003-010-AC (Permit No. PSD-FL-272A): The permittee raised the stacks of Boiler Nos. 1-3 to 213 feet. A revised Air Quality Analysis based on the ISC PRIME model resolved potential adverse ambient

impacts and demonstrated compliance with the AAQS and PSD increments. This model was able to evaluate ambient impact contributions resulting from downwash from each stack. EPA Region 4 approved the non-guideline model for use with this project. Although Boiler Nos. 1 - 3 regain the use of fuel oil containing no more than 2.5% sulfur by weight, additional constraints were used in the analysis, which are included as conditions in this permit.

REGULATORY CLASSIFICATION

HAPs: Based on the most recent information for bagasse-fired boilers, this facility is 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.

NSPS Sources: Fuel oil storage tanks (Emissions Unit Nos. 024 and 026) are subject to regulation under the New Source Performance Standards of 40 CFR 60, Subpart Kb.

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.

- EPA Region 4's approval on November 4, 1999 of the ISC Prime model for use with this project.
- Initial permit application received June 25, 1999, associated correspondence to make complete, and final permit issued on November 22, 1999.
- Permit application for revision received January 6, 2000 and associated correspondence to make complete.

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

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

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-210, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.). The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. Operation Permit Required: This permit authorizes modification of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. In accordance with Chapter 62-213, F.A.C, the permittee shall apply for a Title V operation permit on the appropriate application form with 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.]

A. EU 009 - Boiler No. 4

This portion of the permit addresses the following emissions unit.

EU No.	Emissions Unit Description
009	Boiler No. 4: 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.) 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 psig. The differential pressure drop across the wet scrubber is maintained between 8 and 11 inches of water column. Exhaust gases exit the wet scrubber at an average flow rate of 281,000 ACFM at 160° F. The stack is 150 feet high (GEP stack height is 225 feet high).

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

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

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

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

[b] Based on: 55% thermal efficiency of the boiler when firing bagasse; wet bagasse containing 55% moisture and a heat content of 3600 BTU/lb; and 1160 BTU (net) 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: Any 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 from a dedicated storage tank. 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. Boiler No. 4 shall fire no more than 1500 gallons in any hour and no more than 500,000 gallons in any consecutive 12-month period. The permittee shall install, calibrate, operate, and maintain an individual fuel oil flow meter with integrator. Compliance with these limits shall be determined by the monitoring and record keeping requirements of this permit. [Applicant Request, Rule 62-210.200 (Definitions - PTE) and Rule 62-212.400 (BACT), F.A.C.]

7. Common Conditions: See Section III.B., "Common Conditions for Boiler Nos. 1 - 7" for other performance restrictions.

CONTROL EQUIPMENT AND TECHNIQUES

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

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

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

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

   The monitoring equipment shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations. The permittee shall read and record each scrubber parameter once

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

9. Good Combustion Practices: The boiler operator shall use the Good Combustion Practices (GCPs) defined in *Appendix GCP* to minimize emissions of CO, NOx, PM/PM10 and VOC from this boiler. As a critical part of the GCPs, the permittee shall install, calibrate, operate, and maintain process monitors to indicate the oxygen and carbon monoxide content of the exhaust flue gas in the boiler furnace. The oxygen process monitor shall include an alarm with a set point at 1.5% (minimum) flue gas oxygen content based on a 1-hour block average. It shall display both the instantaneous and the 1-hour block average of the flue gas oxygen content (in percent oxygen). The CO process monitor shall include an alarm with a set point at 3000 ppm (maximum) flue gas CO concentration based on a 1-hour block average. It shall display both the instantaneous and the 1-hour block average of the flue gas CO concentration (in ppm). Readouts of these process monitors shall be provided in the boiler control room. If the alarm is tripped for either process monitor (low oxygen content or high CO concentration), the boiler operator shall take corrective actions consistent with good combustion practices. Corrective actions include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, firing some fuel oil in place of bagasse. For each such incident, the operator shall summarize the corrective actions taken and the approximate time when operation within the target parameter(s) was regained. 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. Operation outside of the specified operating range for either monitored parameter is not a violation of this permit, in and of itself. However, continued or frequent operation outside of the specified operating range for either monitored parameter without corrective action may be considered circumvention of "good combustion practices". [Rules 62-4.070(3) and 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/PM10: Particulate matter emissions shall not exceed 0.15 pounds per mmBTU of heat input from bagasse firing nor 0.10 pounds per mmBTU of heat input from oil firing based on a 3-run test average as

determined by EPA Method 5. Compliance when firing both fuels shall be determined by prorating the emissions standards based on the heat input from each fuel. [Applicant Request; Rules 62-296.410(2)(b)2. and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

21. Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the scrubber pressure drop, the scrubber water supply line pressure, the scrubber water flow rate, the flue gas oxygen content, and the flue gas carbon monoxide content at 15 minute intervals. The permittee shall monitor and record the steam production rate, steam temperature, steam pressure, feed water flow rate, feed water temperature, feed water pressure, and oil flow rate and calculate and record the bagasse consumption rate and the heat input for each run. [Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

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

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

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

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

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

e. **Oil Firing**: The permittee shall record the oil-firing rate (gallons) for each 3-hour block of operation. In addition, the permittee shall calculate and record the oil-firing rate (gallons) for each 24-hour block of operation. Oil firing rates may be observed and recorded by hand or automated monitoring equipment.

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

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

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

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

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

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

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

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

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

EU No.	Emissions Unit Description
001	Bagasse Boiler No. 1 with wet scrubber (255,000 pounds of steam per hour)
002	Bagasse Boiler No. 2 with wet scrubber (230,000 pounds of steam per hour)
003	Bagasse Boiler No. 3 with wet scrubber (130,000 pounds of steam per hour)
004	Bagasse Boiler No. 5 (inactive, permanently shut down)
005	Bagasse Boiler No. 6 (inactive, permanently shut down)
009	Bagasse Boiler No. 4 with wet scrubber (300,000 pounds of steam per hour)
014	Bagasse Boiler No. 7 with electrostatic precipitator (385,000 pounds of steam per hour)

The PSD permit for Boiler No. 4 (PSD-FL-272A) was issued based on an Air Quality Analysis using the ISC PRIME model that contained several operational constraints on existing emissions units. These constraints are now enforceable conditions of the permit and are in addition to any limits imposed by other valid permits. Modification of these constraints would require modification of the PSD permit and a new Air Quality Analysis.

PERFORMANCE RESTRICTIONS

1. Permanent Shutdown: Boiler Nos. 5 and 6 shall remain permanently shut down and rendered incapable of operation. These units are no longer available as "standby" units. Any proposed future operation of either boiler would require a preconstruction review permit as a "new" unit. [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]
2. Modified Stack Heights: The stacks for Boiler Nos. 1, 2, and 3 shall be maintained at a minimum of 213 feet in height. [Design, Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]
3. Crop Season: For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]
4. Capacities: For each boiler, the maximum 1-hour operating capacities shall not exceed:
   a. **Boiler No. 1**: 255,000 pounds of steam per hour, 495 mmBTU per hour of total heat input, and 1500 gallons of oil per hour
   b. **Boiler No. 2**: 230,000 pounds of steam per hour, 447 mmBTU per hour of total heat input, and 1500 gallons of oil per hour
   c. **Boiler No. 3**: 130,000 pounds of steam per hour, 265 mmBTU per hour of total heat input, and 900 gallons of oil per hour
   d. **Boiler No. 4**: 300,000 pounds of steam per hour, 633 mmBTU per hour of total heat input, and 1500 gallons of oil per hour
   e. **Boiler No. 7**: 385,000 pounds of steam per hour, 812 mmBTU per hour of total heat input, and 1839 gallons of oil per hour

   {Permitting Note: No additional record keeping requirements are imposed by these conditions. The steam production chart records are sufficient to demonstrate compliance with these requirements.}

   [Design, Supporting Air Quality Analysis for PSD-FL-272A]

5. Fuel Oil Sulfur Contents

   a. **Boiler Nos. 1 - 3, Crop Season**: From October through April of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 2.50% sulfur by weight.

   b. **Boiler Nos. 1 - 3, Off-Season**: From May through September of each year, any fuel oil fired in Boiler Nos. 1 - 3 shall contain no more than 1.60% sulfur by weight. In April of each year, a composite sample from the common tank shall be taken and analyzed for the sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. If the sulfur content is higher than 1.60% sulfur by weight, the permittee shall purchase additional oil to blend down to the permit limit before any fuel from the common tank is authorized for firing during the off-season. An additional composite sample shall be taken from the common tank after blending and analyzed for the fuel sulfur content. Within 5 days of obtaining the results, a report of the fuel sulfur content shall be submitted to the Compliance Authority. It is a violation of this permit to fire fuel from the common tank without filing a report with the Compliance Authority that demonstrates compliance with the lower fuel sulfur limit. Thereafter, only fuel oil containing no more than 1.60% sulfur by weight shall be purchased and added to the common tank during the off-season. It is the permittee's responsibility to appropriately plan for and stage fuel purchases to comply with this condition.

   c. **Boiler No. 4**: Any fuel oil fired in Boiler No. 4 shall contain no more than 0.70% sulfur by weight.

   d. **Boiler No. 7**: Any distillate oil fired in Boiler No. 7 shall contain no more than 0.05% sulfur by weight.

   The permittee shall maintain fuel records that indicate compliance with the above conditions for each fuel oil purchase at each tank. The sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. For each shipment, a certified analysis supplied by the fuel oil vendor is sufficient to demonstrate compliance.

   [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

6. Fuel Oil Consumption

   a. **Boiler Nos. 1 - 4, Crop Season**: From October through April of each year, the total fuel oil consumption for Boiler Nos. 1 - 4 shall not exceed 16,200 gallons during any 3-hour period and 88,800 gallons during any 24-hour period.

   b. **Boiler Nos. 1 - 4, Off-Season**: From May through September of each year, the total fuel oil consumption for Boiler Nos. 1 - 4 shall not exceed 11,700 gallons during any 3-hour period and 54,000 gallons during any 24-hour period.

   The permittee shall install, calibrate, operate, and maintain individual fuel oil flow meters with integrators.

   [Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

7. Steam Production

   a. **Crop Season and Off-Season**

      (1) Boiler No. 4 shall not produce more than 6,840,000 pounds of steam during any 24-hour period.

      (2) Boiler No. 7 shall not produce more than 8,400,000 pounds of steam during any 24-hour period.

b. **Off-Season (May through September)**

(1) During the off-season, Boiler No. 7 shall be operated as the primary unit to meet the steam demands of the refinery. As restricted by the conditions of this permit, other mill boilers may serve as backup units when Boiler No. 7 is down for maintenance, repair or during periods of unusually low steam demand.

(2) For Boiler Nos. 1 - 4, no more than three of these boilers shall operate simultaneously.

(3) For Boiler Nos. 1 - 4, the total steam production shall not exceed 1,845,000 pounds of steam during any 3-hour period.

(4) For Boiler Nos. 1 - 4, the total steam production shall not exceed 10,800,000 pounds of steam during any 24-hour period.

The permittee shall install, calibrate, operate, and maintain equipment to continuously record the steam production rates. The permittee shall also install, calibrate, operate, and maintain a steam flow integrator to record the accumulated steam flow rate.

[Applicant Request, Supporting Air Quality Analysis for PSD-FL-272A]

8. Modifications: A request to modify any of these conditions shall be accompanied by a revised Air Quality Analysis that demonstrates compliance with the Ambient Air Quality Standards and PSD increments for the revised conditions.

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

PERFORMANCE TESTING

9. SO_2 Tests: To validate the SO_2 emission factor for Boiler Nos. 1 - 3, the permittee shall conduct emissions performance tests in accordance with EPA Method 6 or 6C for at least one of these boilers when firing only bagasse. The initial test shall be conducted between October 1, 2000 and February 1, 2001. Thereafter, at least one of these boilers shall be tested within the 12-month period prior to renewal of the air operation permit. Tests need not be conducted on the same boiler. Based on the results of the performance tests, the Compliance Authority may require additional testing or an additional Air Quality Analysis.

{Permitting Note: The expected emission factor is 0.06 pounds of SO_2 per mmBTU when firing only bagasse. This is not a permit limit for Boiler Nos. 1 - 3. Performance tests, notifications, reports, etc., are subject to the requirements listed in Section III.G. of this permit.}

[Supporting Air Quality Analysis for PSD-FL-272A]

REPORTING AND RECORD KEEPING REQUIREMENTS

10. Steam Production

a. **Crop Season and Off-Season**: For each 24-hour block of operation, the permittee shall record the total steam production rates (pounds, each) for Boiler Nos. 4 and 7 to demonstrate compliance with Condition No. 7 of this section.

b. **Off-Season**

(1) From May through September, the permittee shall record the individual and total steam production rates (pounds) for Boiler Nos. 1 - 4 for each 3-hour block when three of the boilers are in operation.

(2) From May through September, the permittee shall record the individual and total steam production rates (pounds) for Boiler Nos. 1 - 4 for each 24-hour block of operation.

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

11. Fuel Oil Consumption: For Boiler Nos. 1 - 4, the permittee shall record the oil-firing rates (gallons) for each 3-hour block of operation. From this data, the permittee shall calculate and record the combined oil firing rates (gallons) for each 3-hour and each 24-hour block of operation for Boiler Nos. 1 - 4.

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

12. Fuel Sulfur Content: For each fuel oil delivery, the permittee shall record and retain the following: the date, identification of the tank, the gallons of fuel delivered, the fuel oil analysis including the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable. This condition applies to each tank supplying fuel to any boiler.

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

C. EU 024, 025, and 026 - Fuel Tanks for Boilers

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

EU No.	Emission Unit Description
024	NSPS fuel storage tank for Boiler No. 4: Tank with a storage capacity of 100,000 gallons of No. 6 fuel oil (or a superior grade) containing no more than 0.7% sulfur by weight. Constructed in 2000.
025	Common fuel storage tank for Boiler Nos. 1 – 3: Tank with a storage capacity of 400,000 gallons of No. 6 fuel oil (or a superior grade) containing no more than 2.50% sulfur by weight. Constructed prior to 1984.
026	NSPS fuel storage tank for Boiler No. 7: Tank with a storage capacity of 200,000 gallons of No. 2 distillate oil (or a superior grade) containing no more than 2.50% sulfur by weight. Constructed in 1996.

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

RULE APPLICABILITY

The following two conditions apply only to EUs 024 and 026:

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

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

RECORD KEEPING REQUIREMENTS

3. Signs: The permittee shall clearly mark each tank with the following statements:
   a. "Tank for Boiler Nos. 1 -3: From October through April, only fuel oil containing 2.50% sulfur by weight or less may be added to and stored in this tank. From May through September, only fuel oil containing 1.60% sulfur by weight or less may be added to and stored in this tank."
   b. "Tank for Boiler No. 4: Only fuel oil containing 0.70% sulfur by weight or less may be added to and stored in this tank."
   c. "Tank for Boiler No. 7: Only distillate oil containing 0.05% sulfur by weight or less may be added to and stored in this tank."

4. Records: For EU 024 and 026, the permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(b)]

5. Record Retention: For EU 024 and 026, the permittee shall keep a copy of this record for the life of the tank. [Rule 62-204.800(7)(b)16., F.A.C. and 40 CFR 60.116b(a)]

D. EU 017 - Granular Carbon Regenerative Furnace

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

3. Allowable Fuel: Only No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner. The fuel sulfur content shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. [Applicant Request; Rule 62-212.400(BACT), F.A.C.]

CONTROL EQUIPMENT

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

5. GCRF Wet Scrubber: The permittee shall install, operate, and maintain a wet venturi / tray scrubber system designed to control at least 97% of the maximum particulate emissions during regeneration of the

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

EMISSION LIMITING STANDARDS

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

   c. **EPA Method 25A**, "Determination of Volatile Organic Concentrations."

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

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

E. EU 021 - Alcohol Emissions and EU 023 - Propane-Fired Sock Heaters

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

PERFORMANCE RESTRICTIONS

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

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

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

REPORTING AND RECORD KEEPING REQUIREMENTS

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

F. EU 015, 016, 018, 019, 020, AND 022 - MISCELLANEOUS PARTICULATE SOURCES

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

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

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

CONTROL EQUIPMENT AND TECHNIQUES

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

PERFORMANCE RESTRICTIONS

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

EMISSION LIMITING STANDARDS

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

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

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

PERFORMANCE TESTING REQUIREMENTS

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

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

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

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

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

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

EMISSION LIMITING AND PERFORMANCE STANDARDS

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

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

3. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants that cause or contribute to an objectionable odor. An objectionable odor is defined as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]

4. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department's district office and, if applicable, appropriate local program. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the permittee's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. [Rule 62-4.130, F.A.C.]

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

6. Excess Emissions:

   (a) Excess emissions resulting from start-up, shutdown or malfunction of any emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

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

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

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

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

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

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

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

8. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the permittee, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

9. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

10. Calculation of Emission Rate: The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

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

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

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

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

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

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

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial performance tests for NSPS sources and at least 15 days prior to any other required tests. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the permittee. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the permittee of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

16. Records: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

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

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

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

20. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each permittee shall notify the Department or the appropriate local program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department. [Rule 62-210.700(6), F.A.C.]

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

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

The following table summarizes the BACT emissions standards and control technology established in initial Permit No. PSD-FL-272.

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
	Visible Emissions	VE < 20% opacity, except 40% for 2 min./hour
SO2 (SAM)	Fuel Oil Sulfur Limit	0.7% sulfur by weight
	Bagasse Firing	0.06 lb/mmBTU
VOC	Good Combustion Practices	0.50 lb/mmBTU, as propane
EU 024 - NSPS Fuel Storage Tank for Boiler No. 4 (Record Keeping Requirements Only)		
EU 017 - Granular Carbon Regenerative Furnace with Afterburner and Wet Scrubber		
PM/PM10	Controlled by Afterburner and Wet Scrubbing System	0.7 lb/hr
	Surrogate PM Standard	Visible emissions < 10% 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	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

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

G.13 This permit incorporates the following previously issued determinations:

(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 are based upon U.S. Sugar's most recent submittal received by the Department in January of 2001.

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 (including oxygen and carbon monoxide process monitors) 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 includes instruction for observing the oxygen and carbon monoxide process monitors to promote good combustion as well as adjusting operations in response to an alarm condition. 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. Process monitors will be installed to monitor the oxygen (O_2) content and the carbon monoxide (CO) content of the boiler flue gas. The instrument readouts 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 oxygen process monitor will include an alarm with a set point at 1.5% (minimum) flue gas oxygen content based on a 1-hour block average. The CO process monitor will include an alarm with a set point at 3000 ppm (maximum) flue gas CO concentration based on a 1-hour block average. Each monitor will display both the instantaneous and the 1-hour block average. If the alarm is tripped for either process monitor (low oxygen content or high CO concentration), the boiler operator shall take corrective actions consistent with good combustion practices. Corrective actions may include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, firing some fuel oil in place of bagasse. For each such incident, the operator will summarize the corrective actions taken and the approximate time when operation within the target parameter(s) was regained.

NOx Controls

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

Miscellaneous

1. Several times per shift, the boiler grates and feeders are examined for proper distribution and any necessary operational changes are made. Any unusual observations are logged once per shift.

2. Once per day, on the day shift, the boiler will be given a walk-around inspection with the following items being checked and repaired as needed and in coordination with the production schedule: Fans, pumps, casing, ducting, and scrubber.

3. On every shift burners are inspected and cleaned if dirty.

4. On every shift, precautions will be taken as necessary to control visible emissions of fugitive matter (dust and bagasse, etc.)

STARTUP AND SHUTDOWN PROCEDURE

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

During startup and shutdown of the boilers, excess CO, PM, NOx, and VOC emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions shall be taken to minimize the magnitude and duration of excess emissions during startup and

shutdown of Boiler No. 4. The boiler room foreman and operating personnel shall receive proper training on emissions control procedures at least once per year.

Cold Startup (approximately 4 to 5 hours)

1. Feed solid fuel into boiler construction chamber.
2. Start fire in combustion chamber using a propane torch designed for that purpose.
3. As boiler heats up and starts to make steam, continuously observe the boiler and scrubber water levels, and stack plume.
4. Light a burner at the lowest rate, continue to observe the stack plume and adjust if necessary, by adjusting fuel, atomizing steam, and air to obtain proper combustion.
5. Feed carbonaceous fuel from the mill to the boiler slowly at first; as the furnace gets hotter and the carbonaceous fuel is burning better, decrease fuel oil flow until burners can be turned off.
6. Continue to observe the stack plume, the scrubber water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain the optimum operating conditions.

Hot Startup (approximately 1 hour)

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

Shutdown

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

Florida Department of
Environmental Protection

Memorandum

BAR

TO: Howard Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: March 6, 2001

SUBJECT: Final Permit No. 0510003-010-AC (PSD-FL-272A)
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Boiler No. 4 Modification (ISC Prime)

The Final Permit is attached for your approval and signature to modify operations of U.S. Sugar's Boiler No. 4 at the existing Clewiston sugar mill and refinery located in Hendry County. The purpose of this modification is to regain authorization for Boiler Nos. 1- 3 to fire fuel oil containing up to 2.50% sulfur by weight. This authorization was removed in Permit No. PSD-FL-272 because the applicant based the Air Quality Analysis on a lower sulfur content and increased stack heights. These constraints were necessary because of modeled potential adverse impacts related to downwash from the refinery buildings. However, the PSD permit allowed future modification to regain the higher sulfur fuel for Boiler Nos. 1- 3 based on a revised Air Quality Analysis.

During the summer of 2000, construction was completed that raised the stacks for Boiler Nos. 1 – 3 to 213 feet in height. The applicant provided an Air Quality Analysis based on the ISC PRIME model that demonstrates compliance with the Ambient Air Quality Standards and PSD increments. The Air Quality Analysis did include several constraints on boiler operation, fuel oil consumption, fuel oil sulfur content, and steam production. These constraints were included in this permit modification as specific conditions. No new BACT determinations were made as a result of this project.

The Public Notice of Intent to Issue was published in The Clewiston News on December 27, 2000 and proof of publication provided to the Department on January 4, 2001. No comments on the Draft Permit were received from the public, the South District Office, EPA Region 4, or the NPS. The applicant submitted comments that resulted in minor changes to the Final Permit, as summarized in the attached Final Determination. In addition, the applicant requested clarification on two issues related to the Clewiston facility: finishing the installation of previously permitted vacuum pan No. 7; and specific alarm set points for minimum flue gas oxygen content and maximum flue gas carbon monoxide content based on recent test data. After much discussion, agreement was reached and minor changes were also included in the final permit. Resolution of these two issues delayed issuance of the final permit.

Day 90 for this project is April 8, 2001. I recommend your approval and signature.

Attachments

CHF/AAL/jfk

Golder Associates Fax

To: Jeffery Koerner, P. E.
Fax Number: 850-922-6979
Company: FDEP
Date: November 18, 1999
From: David Buff
e-mail: @golder.com
Our ref: 993-7515-0200
Voice Mail:
RE:
Total pages (including cover): 20
Hard copy to follow ☐

MESSAGE

Golder Associates

6241 NW 23rd St., Suite 500
Gainesville, FL 32653
U.S.A.
Telephone: (352) 336-5600
Fax: (352) 336-6603

Comprehensive Consulting Services in Geotechnical Engineering, Environmental Remediation and Waste Management

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Golder Associates Inc.

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

November 17, 1999 9937515A/7

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention : Jeffery Koerner, P.E.

RE: United States Sugar Corporation (U.S. Sugar) – PSD Permit Application for Boiler No. 4 and the Sugar Refinery at the Clewiston Mill
Updated ISC-PRIME Modeling Information

Dear Mr. Koerner:

The purpose of this letter is to address the issues raised by the U.S. EPA in their November 12, 1999, letter regarding the draft Boiler No. 4 PSD permit. The EPA comments are addressed below, in the same order as they appear in the comment letter.

Operational and Emission Limits

1. The current Boiler No. 4 permit restricts the annual fuel oil usage to 500,000 gal/yr, and this same cap was proposed in the permit application for the Boiler No. 4 modification. However, the draft permit did not contain such a condition. To resolve this issue, please add this limitation to the permit (i.e., in Condition 6 under the Boiler No. 4 emission unit section). Also, for modeling purposes for SO_2, it was assumed that Boiler No. 4 was operating at 633MMBtu/hr for the 3-hour averaging time, and at 600 MMBtu/hr for the 24-hour and annual averaging times, which are higher maximum heat inputs than would actually occur under combination bagasse/oil firing. This was done to be conservative, but also because for the 24-hour and annual averaging times, the worst case mill scenario is Boiler No. 4 burning 100 percent bagasse (see discussion below). Boiler No. 4 was modeled for 8,760 hr/yr in all modeling scenarios, since it is proposed to not restrict Boiler No. 4 operation to the crop season (i.e., it can operate any time during the year).
2. No comment.
3. Based on the available SO_2 test data, U.S. Sugar is willing to lower the proposed SO_2 limit for bagasse firing to 0.06 lb/MMBtu in order to resolve this issue. This is about 4 times the highest test data result, but concerns remain over meeting any lower limit on a continuous basis based on the limited test data available, and the ability of measurement methodologies to accurately measure a this low level.

Air Quality Impact Assessment

1. It is agreed that the ISC-PRIME model should provide the basis for the final permit issuance.
2. Based upon the recent approval by EPA of the ISC-PRIME dispersion model for the Clewiston mill, Golder Associates has performed additional modeling analysis in order to bring the project impacts up to date. All model runs have been re-executed using the ISC-PRIME model. In addition, U.S. Sugar seeks the option to raise the existing stacks on Boiler Nos. 1, 2 and 3 from the current 165 feet to a minimum height of 182 feet. This is being done to allow the option of burning the currently permitted 2.5% sulfur (maximum) No. 6 fuel oil in these three boilers. As a result, two sets of model impact results are being provided:
   1) Existing stack heights (Boiler Nos. 1, 2, and 3 @ 165 feet, Boiler No. 4 @ 150 feet, and Boiler No. 7 @ 225 feet), and
   2) Future stack heights (Boiler Nos. 1, 2 and 3 @ 182 feet, Boiler No. 4 @ 150 feet, and Boiler No. 7 @ 225 feet.

PM and CO emissions are not affected by fuel oil burning since maximum emissions occur under 100 percent bagasse firing in all boilers. Therefore, the emissions for these pollutants are the same for both stack height scenarios, and have not changed from that presented in the application.

The maximum mill SO_2 emissions and fuel usage scenario are dictated by the stack height scenario. For the 165 foot stack scenario, Boiler Nos. 1, 2 and 3 will be restricted to burning fuel oil with no greater than 2.0% sulfur in order to comply with all standards and increments. For the 182 foot stack scenario, Boiler Nos. 1, 2 and 3 will be restricted to burning fuel oil with no greater than 2.5% sulfur. The SO_2 emissions for these two scenarios are presented in Tables A and B attached.

A shown in the attached tables, compliance with all standards and increments is predicted with the ISC-PRIME model. The 182 foot scenario tables have a "R1" reference in the table number, while the 165 foot scenario has "R2" in the table number.

The above discussion and modeling results assume that Boiler No. 4 has a separate fuel oil tank for 0.7% sulfur fuel oil, and Boiler Nos. 1, 2, and 3 have a common tank with either 2.0% sulfur or 2.5% sulfur fuel oil. However, until such time that U.S. Sugar constructs a separate fuel oil tank for Boiler No. 4, U.S. Sugar will purchase only 0.7% sulfur fuel for the common tank. Total SO_2 emissions based on 0.7% sulfur fuel oil for Boiler Nos. 1 through 4 will be much less than either of the modeling scenarios presented above with 2.0% or 2.5% fuel oil. As a result, the modeling analysis demonstrates compliance with standards and increments for the scenario of 0.7% sulfur fuel oil being burned in all boilers.

All model input and output files have been placed on Golder's FTP site for access by FDEP and EPA at ftp.golder.com/gville/srm/cleve/USSCLEW.

Please note that U.S. Sugar started purchasing solely 0.7% (maximum) sulfur fuel oil for the common fuel oil tank prior to the beginning of the crop season, and will continue to purchase this fuel for the common tank until such time as a separate fuel oil tank is constructed for Boiler No. 4.

Thank you for consideration of these comments. Please call or e-mail me if you have any additional questions.

Sincerely,

Golder Associates Inc.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/arz

Attachments

cc: Don Griffin
Bill Wehrum
Stan Krivo, EPA Region IV
National Park Service

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Table A. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation:
(09/20/99)

Boilers 1-3 @ 2.5% sulfur fuel oil: 182 ft stack height
Boiler 4 @ 0.7% sulfur fuel oil; 150 ft stack height

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
3	342.0 [c]	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	633.0	225.1	1,500	213.0	420.0	58,333	153.3	42.0 [d]	195.3	24.61
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	798.0	1,980.2	275,028	1,752.3	232.0	1,984.3	250.0
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
2	495.6	225.1	1,400	210.0	285.6	39,667	574.0	19.8	593.8	74.82
3	342.0	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	600.0	225.1	0	0.0	600.0	83,333	0.0	60.0 [d]	60.0	7.56
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,517.0	239.5	1,756.5	221.3

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions, i.e., Boiler Nos. 1, 2 and 3 burning 2.5% sulfur oil, and Boiler No.4 burning 0.7% sulfur oil. Boiler Nos. 1, 2 and 3 have 182 ft stacks, and Boiler No. 4 has a 150 ft stack.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 2.5% sulfur
18,300 Btu/lb; 150,000 Btu/gal
2.5% s 8.2 lb/gal

0.7% sulfur
19,450 Btu/lb; 142,000 Btu/gal
7.3 lb/gal

Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

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Table B. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation
(11/12/99)

Boilers 1-3 @ 2.0% sulfur fuel oil; 165 ft stack height
Boiler 4 @ 0.7% sulfur; 150 ft stack height

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates Used For Modeling Purposes: Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	Modeled SO_2 Emissions: Fuel Oil (lb/hr)	Bagasse [b] (lb/hr)	Total (lb/hr)	Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	492.0	18.8	510.8	64.36
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	492.0	18.8	510.8	64.36
3	342.0 [c]	135.1	900	135.0	207.0	28,750	295.2	14.4	309.6	39.01
4	633.0	225.1	1,500	213.0	420.0	58,333	153.3	42.0 [d]	195.3	24.61
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	798.0	1,980.2	275,028	1,432.5	232.0	1,664.5	209.7
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,400	210.0	285.6	39,667	459.2	19.8	479.0	60.36
2	495.6	225.1	1,400	210.0	285.6	39,667	459.2	19.8	479.0	60.36
3	342.0	135.1	900	135.0	207.0	28,750	295.2	14.4	309.6	39.01
4	600.0	225.1	0	0.0	600.0	83,333	0.0	60.0 [d]	60.0	7.56
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	1,116.2	293,917	1,213.6	239.5	1,453.1	183.1

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions, i.e., Boiler Nos. 1, 2 and 3 burning 2.0% sulfur oil, and Boiler No.4 burning 0.7% sulfur oil. Boiler Nos. 1, 2 and 3 have 165 ft stacks, and Boiler No. 4 has a 150 ft stack.

[b] Assumes 75% removal of SO_2 due to bagasse firing, based on industry test data.

[c] Permit limit for 24-hour average.

[d] Based on proposed permit limit for Boiler No. 4 of 0.1 lb/MMBtu, and current permit limit of 0.17 lb/MMBtu for Boiler No. 7.

Note: Fuel Oil - 2.0% sulfur
18,300 Btu/lb; 150,000 Btu/gal
2.5% s 8.2 lb/gal

0.7% sulfur
19,450 Btu/lb; 142,000 Btu/gal
7.3 lb/gal

Bagasse - 7,200 Btu/lb (dry); 3,600 Btu/lb (wet)
0.1% sulfur average, dry basis

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Table 6-16R. Maximum Predicted Pollutant Impacts From Proposed Project
Screening Analysis - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	1.75	300	1500	87123124
	1.59	270	1500	88123124
	1.88	310	1500	89123124
	2.08	300	1500	90123124
	1.99	300	1500	91123124
High 24-Hour				
	27.9	240	900	87110124
	25.7	260	1200	88013024
	18.4	310	1500	89040424
	25.3	240	900	90042024
	24.0	290	1200	91052124
High 3-Hour				
	77	10	463	87011915
	92	360	456	88112306
	65	350	900	89022118
	60	240	900	90100812
	69	10	463	91030309
PM10				
Annual				
	0.80	120	675	87123124
	0.86	110	906	88123124
	0.61	310	1200	89123124
	0.79	300	1200	90123124
	0.86	300	1200	91123124
High 24-Hour				
	8.4	230	1200	87102324
	7.9	60	912	88041224
	8.0	310	1500	89040424
	11.5	240	900	90042024
	10.2	290	1200	91052124
NOx				
Annual				
	0.71	300	1500	87123124
	0.62	270	1500	88123124
	0.75	310	1500	89123124
	0.82	300	1500	90123124
	0.81	300	1500	91123124
CO				
High 8-Hour				
	1065	50	709	87062716
	891	350	600	88041816
	707	340	900	89060816
	795	240	900	90100816
	866	350	900	91042316
High 1-Hour				
	2097	350	1200	87071916
	2208	10	463	88090511
	2200	10	463	89062816
	1966	10	463	90071311
	1662	360	600	91050111

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

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11/17/99

Table 6-17R. Maximum Predicted Pollutant Impacts From Proposed Project for Comparison to EPA Significant Impact Levels - Refined Analyses - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (μmg/m^3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	EPA Significant Impact Levels (μg/m^3)
SO_2					
Annual	2.1	302	1500	90123124	1
	2.0	300	1500	91123124	
High 24-Hour	28.3	240	800	87110124	5
	25.9	260	1100	88013024	
	32.6	244	1000	90042024	
High 3-Hour	92	360	456	88112306	25
PM10					
Annual	1.54	100	800	88123124	1
	0.86	302	1200	91123124	
High 24-Hour	13.8	244	1000	90042024	5
	11.1	292	1100	91052124	
NOx					
Annual	0.75	306	1500	89123124	1
	0.82	300	1500	90123124	
	0.81	300	1500	91123124	
CO					
High 8-Hour	1,065	50	709	87062716	500
High 1-Hour	2,134	350	1100	87071916	2000
	2,200	10	463	89062816	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Note: The project's significant impact distances (km) are SO2 - 12; PM10 - 4; CO - 3; NOx = Not significant

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

EPA = Environmental Protection Agency

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11/17/99

Table 6-18R. Maximum Predicted Pollutant Impacts From Proposed Project at the Everglades National Park PSD Class I Area - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (ug/m³)	UTM Receptor Location[b] (m)	(m)	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Levels (ug/m³)
SO_2					
Annual					
	0.022	550300	2848600	87123124	0.1
	0.031	550300	2848600	88123124	
	0.031	545000	2848600	89123124	
	0.022	550300	2848600	90123124	
	0.027	545000	2848600	91123124	
High 24-Hour					
	0.49	540000	2848600	87021224	0.2
	0.50	535000	2848600	88071824	
	0.45	525000	2848600	89022824	
	0.67	545000	2844000	90082724	
	0.68	473500	2860000	91101924	
High 3-Hour					
	2.3	483000	2848500	87090706	1.0
	3.6	540000	2848600	88040603	
	3.6	525000	2848600	89022806	
	3.6	540000	2844000	90112603	
	2.9	545000	2848600	91012306	
PM10					
Annual					
	0.006	550300	2848600	87123124	0.2
	0.008	550300	2848600	88123124	
	0.008	545000	2848600	89123124	
	0.006	550300	2848600	90123124	
	0.006	550300	2848600	91123124	
High 24-Hour					
	0.18	545000	2829000	87050724	0.3
	0.22	535000	2848600	88071824	
	0.19	545000	2848600	89041924	
	0.31	545000	2844000	90082724	
	0.30	473500	2857000	91101924	
NOx					
Annual					
	0.009	550300	2848600	87123124	0.1
	0.012	550300	2848600	88123124	
	0.012	545000	2848600	89123124	
	0.009	550300	2848600	90123124	
	0.010	545000	2848600	91123124	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Universal Mercator Transverse coordinate system

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending

PSD = Prevention of Significant Deterioration

NPS = National Park Service

EPA = Environmental Protection Agency

Table 6-18AR. Maximum Predicted 24-Hour PM10 Pollutant Impacts From Proposed Project at the Everglades National Park
PSD Class I Area - Refinement - Future Boiler No. 4 @ 0.7 % S Oil

Averaging Time	Concentration[a] (mg/m^3)	Receptor Location[b] X (km)	Receptor Location[b] Y (km)	Time Period (YYMMDDHH)	EPA Proposed Class I Significant Impact Level (mg/m^3)
High 24-Hour					
	0.168	62.92	-80.54	87112924	0.3
	0.169	60.07	-82.68	88011224	
	0.171	-84.73	-57.15	89080224	
	0.154	44.80	-91.86	90121324	
	0.165	-82.68	60.07	91040824	

[a] Concentrations are highest predicted with CALPUFF model and 5-year meteorological record from W. Palm Beach, 1987-91

[b] Receptors are relative to the Clewiston Mill and are located on a circle of 102 km radius, and spaced at 2-degrees intervals

Legend:

YYMMDDHH = Year, Month, Day, Hour Ending
PSD = Prevention of Significant Deterioration
NPS = National Park Service
EPA = Environmental Protection Agency

Table 6-19R1. Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analyses - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2				
Annual				
	29.9	310	1200	87123124
	31.1	270	1200	88123124
	33.9	310	1200	89123124
	35.8	310	1200	90123124
	33.2	300	1200	91123124
H2H 24-Hour				
	231	310	1200	87080724
	240	310	1200	88040324
	217	320	900	89061524
	208	320	900	90031624
	203	320	1200	91041624
H2H 3-Hour				
	552	310	900	87080715
	615	310	900	88090912
	574	310	900	89061212
	561	270	900	90092115
	728	310	900	91070615
PM_{10}				
Annual				
	5.5	310	1200	87123124
	5.7	270	1200	88123124
	6.4	310	1200	89123124
	6.8	310	1200	90123124
	6.3	300	1200	91123124
H2H 24-Hour				
	48.7	270	1200	87123124
	49.0	310	1500	88112024
	45.2	320	900	89060424
	43.9	320	1200	90020324
	44.3	290	1200	91050924
CO				
H2H 8-Hour				
	3781	310	900	87061416
	3824	280	1200	88032408
	3978	320	900	89060516
	3323	320	1200	90031508
	4211	310	900	91043016
H2H 1-Hour				
	7822	340	900	87072410
	7798	320	900	88040612
	7930	320	900	89051714
	8872	330	527	90080511
	9124	40	600	91081212

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-20R1. Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration (mg/m^3)			Receptor Location[b]		Time Period	Florida AAQS
	Total	Modeled	Background	Direction (degree)	Distance (m)	(YYMMDDHH)	(mg/m^3)
SO_2							
Annual	39.7	34.7	5	316	1100	89123124	60
	40.9	35.9	5	310	1100	90123124	
	38.2	33.2	5	300	1200	91123124	
H2H 24-Hour	258	245	13	316	1100	87032424	260
	253	240	13	310	1200	88040324	
H2H 3-Hour	775	728	47	310	900	91070615	1300
PM_{10}							
Annual	29.6	6.6	23	316	1100	89123124	50
	29.8	6.8	23	310	1100	90123124	
H2H 24-Hour	90	51	39	272	1100	87123124	150
	88	49	39	310	1500	88112024	
CO							
H2H 8-Hour	7761	4331	3430	318	900	89060416	10000
	7681	4251	3430	310	800	91043016	
H2H 1-Hour	14839	9124	5715	40	600	91081212	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

Table 6-21R1. Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (mg/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	0.1	250	11000	87123124
	0.0	0	0	88123124
	0.0	0	0	89123124
	0.1	210	11000	90123124
	0.0	0	0	91123124
H2H 24-Hour				
	7	30	11000	87030524
	9	350	11000	88060224
	12	80	11000	89040224
	11	100	11000	90042124
	8	50	11000	91040824
H2H 3-Hour				
	29	60	11000	87041324
	46	60	11000	88040521
	48	70	11000	89041303
	33	120	11000	90042203
	36	80	11000	91041121
PM_{10}				
Annual				
	<0	0	0	87123124
	<0	0	0	88123124
	<0	0	0	89123124
	<0	0	0	90123124
	<0	0	0	91123124
H2H 24-Hour				
	4.9	320	900	87100624
	6.4	330	900	88062824
	5.9	350	900	89073024
	5.4	310	900	90082924
	6.0	310	900	91083124

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-22R1. Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment ($\mu g/m^3$)
		Direction (degree)	Distance (m)		
SO_2					
Annual	0.1	250	11000	87123124	20
H2H 24-Hour	12.2	78	11000	89042324	91
H2H 3-Hour	47.7	70	11000	89041303	512
PM_{10}					
Annual	<0	0	0	0	17
H2H 24-Hour	7.6	332	1200	88081424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

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Table 6-23R1. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area - Boiler Nos. 1, 2, and 3 @ 182 ft and @ 2.5 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (ug/m^3)
Annual					
	0.16	550300	2848600	87123124	2
	0.14	535000	2848600	88123124	
	0.10	540000	2848600	89123124	
	0.20	545000	2848600	90123124	
	0.09	540000	2848600	91123124	
H2H 24-Hour					
	2.3	550300	2848600	87052924	5
	3.0	545000	2848600	88060224	
	2.8	545000	2848600	89040124	
	3.2	530000	2848600	90041224	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.5	530000	2848600	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
H2H = Highest, 2nd-Highest

Table 6-19R2. Maximum Predicted Pollutant Impacts Due to All Future Sources, AAQS Screening Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m³)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2				
Annual				
	28.9	310	900	87123124
	30.6	270	900	88123124
	32.8	320	900	89123124
	35.0	270	900	90123124
	31.9	300	1200	91123124
H2H 24-Hour				
	224	310	1200	87080724
	231	310	1200	88040324
	214	320	900	89061524
	209	320	900	90031624
	198	320	900	91041624
H2H 3-Hour				
	528	310	900	87041418
	594	310	900	88090912
	530	310	900	89061212
	507	310	900	90122224
	655	310	900	91072412
PM_{10}				
Annual				
	6.3	310	900	87123124
	6.7	270	900	88123124
	7.2	320	900	89123124
	7.8	270	900	90123124
	7.1	300	1200	91123124
H2H 24-Hour				
	59	270	900	87123124
	56	310	1200	88112024
	53	320	900	89060424
	55	250	900	90042024
	57	260	1200	91102424
CO				
H2H 8-Hour				
	4,182	310	900	87061416
	4,501	280	1200	88032408
	4,388	310	900	89041416
	4,240	250	900	90022708
	4,741	310	900	91043016
H2H 1-Hour				
	8,531	320	600	87090213
	8,681	320	600	88090413
	8,908	320	600	89061511
	9,229	330	527	90080511
	9,723	40	595	91061812

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

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Table 6-20R2. Maximum Predicted Pollutant Impacts Due to All Future Sources For Comparison to AAQS, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration ($\mu g/m^3$)			Receptor Location[b]		Time Period (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
	Total	Modeled	Background	Direction (degree)	Distance (m)		
SO_2							
Annual	38.7	33.7	5	316	1000	89123124	60
	40.3	35.3	5	272	1000	90123124	
	37.1	32.1	5	300	1100	91123124	
H2H 24-Hour	255	242	13	316	1000	87032424	260
	246	233	13	310	1000	88040324	
H2H 3-Hour	708	661	47	310	800	91070815	1300
PM_{10}							
Annual	30.8	7.8	23	272	1000	90123124	50
H2H 24-Hour	101	62	39	272	1000	87123124	150
	98	59	39	322	1000	88112624	
	96	57	39	260	1100	91102424	
CO							
H2H 8-Hour	7,962	4,532	3,430	280	1100	88032408	10000
	6,310	4,880	3,430	312	700	91043016	
H2H 1-Hour	15,438	9,723	5,715	40	595	91061812	40000

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

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Table 6-21R2. Maximum Predicted Pollutant PSD Class II Increment, Screening Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)
		Direction (degree)	Distance (m)	
SO_2				
Annual				
	0.17	250	11000	87123124
	0.03	220	11000	88123124
	0.00	0	0	89123124
	0.18	210	11000	90123124
	0.04	210	11000	91123124
H2H 24-Hour				
	6.8	30	11000	87030524
	9.0	350	11000	88060224
	11.7	80	11000	89040224
	10.7	100	11000	90042124
	8.4	50	11000	91040824
H2H 3-Hour				
	29	60	11000	87041324
	46	60	11000	88040521
	48	70	11000	89041303
	33	120	11000	90042203
	36	80	11000	91041121
PM_{10}				
Annual				
	<0	0	0	87123124
	0.04	340	1200	88123124
	<0	0	0	89123124
	0.06	330	1500	90123124
	0.04	340	1200	91123124
H2H 24-Hour				
	6.5	360	1200	87071924
	8.6	330	900	88062824
	7.3	320	900	89071224
	7.7	310	900	90082724
	10.4	310	900	91072424

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

PSD = Prevention of Significant Deterioration

Table 6-22R2. Maximum Predicted Pollutant PSD Increment Consumption For Comparision With PSD Class II Allowable Increments, Refined Analysis - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration (ug/m^3)	Receptor Location[b]		Time Period (YYMMDDHH)	Allowable PSD Class II Increment (ug/m^3)
		Direction (degree)	Distance (m)		
SO_2					
Annual	0.2	210	11000	90123124	20
H2H 24-Hour	12.2	78	11000	89042324	91
H2H 3-Hour	46.9	64	11000	88042924	512
	47.7	70	11000	89041303	
PM_{10}					
Annual	0.07	322	1500	90123124	17
H2H 24-Hour	11.5	308	900	91072424	30

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Boiler Number 4 Stack Location

Notes:

YYMMDDHH = Year, Month, Day, Hour Ending

H2H = Highest, 2nd-Highest Concentration in 5 years.

EPA = Environmental Protection Agency

PSD = Prevention of Significant Deterioration

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Table 6-23R2. Maximum Predicted SO_2 PSD Increment at the Everglades National Park PSD Class I Area - Boiler Nos. 1, 2, and 3 @ 165 ft and @ 2.0 % S; Boiler No. 4 @ 0.7 % S

Averaging Time	Concentration[a] (ug/m^3)	Receptor Location (UTM) (m)	(m)	Time Period (YYMMDDHH)	Allowable PSD Class I Increment (ug/m^3)
Annual					
	0.18	550300	2848600	87123124	2
	0.16	535000	2848600	88123124	
	0.12	550300	2848600	89123124	
	0.22	545000	2848600	90123124	
	0.11	535000	2848600	91123124	
H2H 24-Hour					
	2.3	550300	2848600	87052924	5
	3.0	545000	2848600	88060224	
	2.8	545000	2848600	89040124	
	3.2	530000	2848600	90041224	
	2.5	550300	2848600	91100924	
H2H 3-Hour					
	17.7	540000	2848600	87041303	25
	24.2	540000	2848600	88042209	
	18.1	550300	2848600	89042924	
	19.1	540000	2848600	90020706	
	14.5	530000	2848600	91100915	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

Legend:
PSD = Prevention of Significant Deterioration
YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator
H2H = Highest, 2nd-Highest

Golder Associates Fax

To: Jeff Koerner **Fax Number:** 850-922-6979

Company: FDEP **Date:** August 30, 1999

From: Dave Buff **e-mail:** @golder.com

Our ref: 993-7515 **Voice Mail:**

RE:

Total pages (including cover: 25 **Hard copy to follow** ☐

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August 23, 1999 9937515

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road
Tallahassee, FL

Attention: Jeffery Koerner, P.E.

RE: U.S. SUGAR – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
RESPONSE TO REQUEST FOR INFORMATION NO. 2

Dear Mr. Koerner:

This letter is in response to your draft completeness letter e-mailed to me on August 16 concerning U.S. Sugar's PSD Permit Application to modify operation of Boiler No. 4 and expand the sugar refinery operation at their mill located in Clewiston, Florida. This letter is organized in the same manner as your draft completeness letter. Responses to each item are presented below, numbered according to the original question numbers.

4. An analysis of the cost effectiveness of reducing SO_2 emissions by buying fuel oil with a sulfur content of less than 1.5 percent is presented in the attached tables. A summary of fuel costs and calculated emission rates for several scenarios is presented in Table 4-1. A cost efficiency evaluation of the following SO_2 emissions reduction options is presented in Tables 4-2 through 4-5:

    1. Replacing the current 1.5 percent sulfur No. 6 fuel oil burned with 0.7-percent sulfur No. 6 fuel oil, and storing it in the existing common storage tank used to supply Boiler Nos. 1, 2, 3, and 4.
    2. Replacing the current 1.5-percent sulfur No. 6 fuel oil burned with 0.7 percent sulfur No. 6 fuel oil, and storing it in a new storage tank.
    3. Replacing the current No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.5 percent. This option would require a new storage tank (No. 6 and No. 2 fuel oil are not miscible) and replacement of the current oil burners in Boiler No. 4, which are not capable of firing No. 2 fuel oil.
    4. Replacing the current No. 6 fuel oil burned with No. 2 fuel oil with a sulfur content of 0.05 percent. This option would also require a new storage tank and burner replacement.

    It is noted that, for cost effectiveness calculations, the top-down BACT guidance document (draft) allows the use of past historical operation and emissions. Thus,

even though Boiler No. 4 is permitted to burn 500,000 gal/yr of fuel oil, actual historic operation (last 3 years) indicates only about 100,000 gal/yr of fuel oil is burned. The actual fuel oil consumption and resulting SO_2 emissions were used for the cost effectiveness calculations.

The results of the analysis are shown in Table 4-6. Clearly, the cost efficiencies of the two options involving switching to No. 2 fuel oil are unreasonable (over $8,000 per ton of SO_2 removed). This is due to the relatively small reduction in SO_2 emissions (approximately 12 tons) measured against the capital cost of a new storage tank and replacement of the burners ($395,000). Option 2 was included at the request of FDEP. The only difference between Option 1 and Option 2 is that Option 1 employs the use of the existing common storage tank, while Option 2 includes installation of a new storage tank at a substantial cost to U.S. Sugar. It is emphasized that the installation of a new storage tank is not justified as it affords no additional SO_2 control over that afforded by Option 1, but increases the cost of SO_2 removal by nearly $5,000 per ton.

Given the costs associated with switching Boiler No. 4 to No. 2 fuel oil or adding another No. 6 fuel oil tank, U.S. Sugar requests that BACT be determined to be the use of No. 6 fuel oil with a sulfur content of 0.7 percent.

The potential reductions in SO_2 emissions that may be obtained by lowering the overall sulfur content of fuel oil fired in the common fuel oil tank was also analyzed. Based on the last 2 years of operation for Boiler Nos. 1 through 4, total fuel oil burning averaged 970,000 gal/yr, sulfur content averaged 2.3 percent, and SO_2 emissions averaged 192 TPY. Switching to 0.7-percent sulfur No. 6 fuel oil would, therefore, lower actual SO_2 emissions by about 134 TPY. The cost of such reduction, based on the information presented in Tables 4-1 through 4-6, would be approximately $700/ton of SO_2 removed (similar to Option 1 in the above analysis). It is cautioned, however, that the PSD rules do not bring the other boilers under the review requirements. The other boilers are not part of the proposed "modification". Only the modification itself (Boiler No. 4 and the sugar refinery) is subject to BACT.

In addition, the proposed project no longer results in an increase in SO_2 emissions of 350 TPY. Attached are revised tables which show the maximum short-term emissions (Table 2-1), the future maximum annual emissions (Table 2-2), the current baseline emissions (Table 3-3) and the net increase in emissions (Table 3-4) for Boiler No. 4. Also attached is a revised Table 1-1, which shows the total net increase in emissions for Boiler No. 4 and the sugar refinery. Tables 2-1 and 2-2 have been revised to reflect the 0.7-percent sulfur fuel oil, as well as a lower SO_2 limit for bagasse firing (refer to Item 5 below). These changes affect SO_2 and sulfuric acid mist emissions. Baseline emissions (Table 3-3) have been revised to correct some minor typographical errors. These changes are reflected in the revised Tables 1-1 and 3-4. Also attached are revised permit application form pages, which reflect these changes.

5. SO_2 removal is inherent to the process of combusting bagasse. The fly ash produced during bagasse firing is alkaline in nature and acts as a dry scrubbant adsorbing SO_2

from the exhaust stream. The fly ash, along with the adsorbed SO_2, is then removed by the scrubber. The alkaline nature of the fly ash also maintains the pH of the scrubber water between 5 and 8, further enhancing SO_2 removal. Evidence of the inherent removal of SO_2 is apparent on review of the SO_2 stack test results for Boiler No. 7 presented in our last correspondence. The only control equipment employed on Boiler No. 7 is an ESP, yet SO_2 removal efficiencies average 96 percent. As shown in the stack tests for Boiler No. 4, also presented in our last response, the average removal efficiency with the addition of a scrubber only increases to 97 percent. As such, monitoring the pH of the scrubber water is not necessary as an indicator of the efficiency of SO_2 control. It is noted that for air dispersion modeling purposes, a 75-percent SO_2 removal efficiency was assumed for Boiler Nos. 1, 2, and 3 for bagasse firing.

To the best of our knowledge, specific stack tests have not been performed to quantify the potential control effectiveness of maintaining or enhancing the alkaline scrubbing media. Based on the SO_2 stack tests performed on the wet scrubber sources at Clewiston, U.S. Sugar is willing to reduce the allowable SO_2 emission limit for bagasse to 0.1 lb/MMBtu, which allows an adequate safety margin above the actual test results. U.S. Sugar is also willing to conduct a stack test to once again verify that this emission limit is being met.

10. See our response to Item 5.

12. Using information from the last five stack tests the actual range for the scrubber pressure drop has historically ranged from 9 to 10 inches H_2O. Based on this actual operation, for which compliance with the particulate matter (PM) emission limit was demonstrated, the optimum range for pressure drop is 7 to 12 inches H_2O. As you have discovered in the Boiler No. 4 permit files, the scrubber manufacturer (Joy) based their PM emission guarantee on a pressure drop from 5 to 9 inches H_2O. U.S. Sugar, based on actual operating experience, typically operates slightly above this range to obtain better performance and improved PM removal.

13. As described in our previous response, there is no historic boiler oxygen concentration level data for Boiler No. 4. The boiler is not equipped with an oxygen monitor. Oxygen at the stack is measured during stack testing, but this oxygen level is not representative of boiler oxygen levels due to significant air infiltration into the exhaust gases between the boiler and the stack. The other boilers at the Clewiston mill that are similar to Boiler No. 4 (Boiler Nos. 1, 2, and 3) also do not have oxygen monitors.

Boiler No. 8 at the Sugar Cane Growers Cooperative has an oxygen meter, and the O&M plan for the boiler requires that an alarm be triggered if the oxygen level in the boiler drops below 4 percent. The time the boiler operates with less than 4-percent oxygen must be logged. The O&M plan states that the goal is to maintain the flue gas oxygen content at or above 4 percent, to the extent practical without sacrificing proper boiler operation and consistent with meeting steam demands.

In consideration of the Department's desire to implement methods of potentially lowering CO and VOC emissions, U.S. Sugar is willing to install a flue gas oxygen monitor on Boiler No. 4 during the upcoming crop season. The flue gas oxygen content will be recorded on an hourly basis. It is proposed that data collection continue for three crop seasons, which will include stack testing for CO and VOC emissions in each of these three seasons. After this data collection, the data will be evaluated and an appropriate range of oxygen level established for the boiler. The oxygen monitor will then be configured to trip an alarm whenever the oxygen content falls outside the established range. Corrective actions would then be implemented to bring the oxygen level within the established range, consistent with proper boiler operation and meeting steam production demands.

In addition, U.S. Sugar agrees to lower their proposed VOC emission limit from the previous requested level of 1.5 lb/MMBtu to a more realistic 0.5 lb/MMBtu. Although there is no recent VOC test data for this boiler, U.S. Sugar believes this is a reasonable limit based on the boiler design. Revised calculation tallies are attached.

16. The GCRF has never been tested for SO_2 emissions, and such testing is not a requirement of the current permit. However, as we discussed, the SO_2 emissions are solely due to fuel oil combustion in the furnace and, therefore, there is no need to perform stack testing (fuel analysis should suffice). The critical parameters for operation of the afterburner on the GCRF is afterburner temperature, while pressure drop is critical on the venturi scrubber.

21. We are pursuing approval of the ISC-PRIME model through discussions with Cleve Holladay and EPA Region IV.

22. The questions received to date from the National Park Service (NPS) so far are answered below.

In regards to the comment that we have not provided a top-down BACT analysis for each pollutant, nor suggested a method to substantially reduce such emissions the following is provided. For SO_2, the response to Question 4 above should provide you with this information. For CO and VOC, there are no known or proven methods for reducing these emissions from an existing boiler, other than proper boiler operation. The response to Question 13 above provides a plan for acquiring to data to ultimately reduce emissions. However, data must first be collected and evaluated prior to implementing any specific actions. In regards to NO_x, emissions from this boiler are already very low (NO_x emissions averaged 0.08 lb/MMBtu) and do not warrant further reduction. Any measures to reduce CO and VOC emissions will likely increase NO_x emissions.

Responses to NPS Comments:

PSD Applicability

Baseline (actual) emission rate calculations for all regulated pollutants emitted from Boiler No. 4 were presented in Table 3-3 of the PSD permit application. A copy of Table 3-3 is

attached for your review. These emission rate calculations are based on average operation of Boiler No. 4 during 1997 and 1998.

Due to the short operational history (less than 2 years), the sugar refinery and its proposed expansion were considered a new source in the PSD permit application. As such, emissions of VOC and PM associated with the proposed expansion of the sugar refinery were addressed in the PSD analysis.

In regards to emissions from the sugar mill and bagasse handling system, refer to the response to FDEP Comment 1 above.

Best Available Control Technology

Particulate Matter

The cost effectiveness (dollars per ton of PM removed) of an ESP is significantly less for Boiler No. 7 than for Boiler No. 4 for one main reason: Boiler No. 7 was a new boiler and, therefore, its uncontrolled emissions were the basis of the cost effectiveness calculations. Boiler No. 4 is an existing source with controlled PM emissions averaging 0.12 lb/MMBtu. This is the starting point for its cost effectiveness calculations, not uncontrolled emissions. As such, annual emissions for cost effectiveness calculations for Boiler No. 7 are much higher than for Boiler No. 4.

Other factors which render the Boiler No. 7 cost effectiveness lower are: 1) Boiler No. 7 is permitted to operate on full load year around (Boiler No. 4 will be limited to an equivalent of 200 days/yr operation); 2) Boiler No. 7 has a higher heat input rate than Boiler No. 4 (812 compared to 633 MMBtu/hr); and 3) because of design and operation with a wet scrubber, Boiler No. 4 has a significantly larger exhaust flow (344,800 compared to 254,587 acfm) that increases the capital cost of an ESP from $2,000,000 to $2,700,000. Both these factors lower the cost efficiency of an ESP making it economically feasible for Boiler No. 7, but not for Boiler No. 4. Boiler No. 7 is certainly not similar to Boiler No. 4, in design or operation and, therefore, separate cost analysis are warranted.

The NPS also had several comments concerning validity of the cost analysis presented to rule out an ESP for Boiler No. 4 based on economic feasibility. These concerns are addressed below:

1. A wet cyclone was included in the cost analysis because the existing impingement scrubber would need to be replaced due to excessive moisture in the flue gas, which would interfere with the operation of an ESP.
2. Working capital costs are less than 1 percent of the total capital investment and, therefore, the costs are not significant.
3. The estimate that an operator will be required for 8 hours per day is based on operational experience for Boiler No. 7; the only known application of an ESP on a bagasse fired boiler. This figure is due to the lack of any previous operating experience with an ESP in the sugar industry. As the OAQPS cost manual is intended as a guide in lieu of situation-specific information, U.S. Sugar's

operational experience is a better indicator of the time and effort required to operate and maintain an ESP on a bagasse fired boiler.

4. The capital cost recovery factor of 7 percent presented in the OAQPS cost manual is used to illustrate example cost calculations. More appropriately, the actual cost of borrowing money should be used, which in this case was assumed to be 10 percent and is representative of current economic conditions.
5. The OAQPS manual indicates a range of useful equipment life for an ESP of 5 to 40 years. Due to the lack of industry data for a ESP on a bagasse fired boiler and the maintenance/replacement costs already incurred for the ESP on Boiler No. 7, a conservative estimate of 10 years was used for the equipment life of the ESP in this cost analysis.
6. The efficiency of the ESP for both cases (Boiler No. 4 and Boiler No. 7) were based on the vendor guarantee of 0.03 lb/MMBtu, although this level of emissions was not achievable on Boiler No. 7 until the wet cyclone was added preceding the ESP. The only difference is that for Boiler No. 4 the current emissions are already down to 0.12 lb/MMBtu, but an ESP would still only achieve a 0.03 lb/MMBtu emission level, since the existing scrubber would be replaced.

Nitrogen Oxides

As stated in the permit application, through good combustion practices, U.S. Sugar achieves an average NO_x emission rate of 0.08 lb/MMBtu. However, U.S. Sugar cannot accept a BACT limit based on average emissions, since this limit will have to be achieved on a continuous basis. Review of the NO_x test data presented in Appendix C of the application shows that stack test results vary from 0.03 to 0.16 lb/MMBtu. Given this variability in NO_x emissions, U.S. Sugar requests an emission limit of 0.25 lb/MMBtu as previously determined as BACT for this unit.

Sulfur Dioxide

Refer to Items 4 and 5 above for a response to this comment.

Thank you for consideration of these responses. Please call or e-mail me if you have any additional questions.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E.
Principal Engineer
Florida P.E. #19011

DB/jkk

Enclosures
cc: Don Griffin
Bill Wehrum
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Table 4-1. Fuel Cost and SO_2 Emission Rate Analysis

Fuel Type/ Sulfur Content	Unit Cost ($/gal)	Usage (gal/yr)		Annual Cost ($/yr)	Cost Increase ($/yr)	SO_2 Emission Rate[a] (TPY)
No. 6 Fuel Oil						
1.5% Sulfur	0.5750	102,350	[b]	58,851	--	12.6
0.7% Sulfur	0.6179	103,032	[c]	63,659	4,808	5.7
No. 2 Fuel Oil						
0.5% Sulfur	0.6607	109,661	[c]	72,454	13,603	3.7
0.05% Sulfur	0.6845	113,722	[c]	77,846	18,994	0.4

Notes:
1. All prices based on Coastal Fuels Marketing, Inc.'s current prices (FOB)

Footnotes:

[a] Based on the following information:

Fuel Type	Sulfur Content (% by wt.)	Heat Content (Btu/gal)	Density (lb/gal)
No. 2 Fuel Oil	0.5	140,000	6.83
	0.05	135,000	6.83
No. 6 Fuel Oil	1.5	151,000	8.22
	0.7	150,000	7.94

[b] Based on actual average usage of No. 6 fuel oil in 1996, 1997, and 1998 of 96,968, 90,686, and 119,395 gallons, respectively.

[c] Gallons needed for equivalent heat input to No. 6 fuel oil with a sulfur content of 1.5%.

Table 4-2. Cost Effectiveness of No. 6 Fuel Oil (0.7% Sulfur Content With a Common Tank) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	Not applicable	0
INDIRECT CAPITAL COSTS (ICC):[b]		
Indirect Installation Costs	Not Applicable	
(a) Engineering	Not Applicable	
(b) Construction & Field Expenses	Not Applicable	
(c) Construction Contractor Fee	Not Applicable	
(d) Contingencies	Not Applicable	
Other Indirect Costs		
(a) Startup & Testing	Not Applicable	
(b) Working Capital	Not Applicable	
Total ICC:		0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	0
DIRECT OPERATING COSTS (DOC):[c]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 6 Fuel (0.7% Sulfur Content)	See Footnote "d"	4,808
Total DOC:		4,808
INDIRECT OPERATING COSTS (IOC):[c]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	0
Insurance	1% of total capital investment	0
Administration	2% of total capital investment	0
Total IOC:		0
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	0
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	4,808
BASELINE SO_2 EMISSIONS (TPY) :	102,350 gallons No. 6 Fuel Oil with a Sulfur of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 6 FUEL OIL (TPY):	103,032 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	5.7
REDUCTION IN SO_2 EMISSONS (TPY):		6.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	697

Footnotes:

[a] All direct installation costs are included in basic price.

[b] All indirect installation costs are included in basic price.

[c] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[d] Increase in fuel cost associated with buying No. 6 fuel oil with a sulfur content of 0.7% ($0.6179/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 103,032 gallons per year.

Table 4-3. Cost Effectiveness of No. 6 Fuel Oil (0.7% Sulfur Content With a New Tank) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	170,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	170,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 6 Fuel (0.7% Sulfur Content)	See Footnote "e"	4,808
Total DOC:		4,808
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	1,700
Insurance	1% of total capital investment	1,700
Administration	2% of total capital investment	3,400
Total IOC:		6,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	27,659
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	39,267
BASELINE SO_2 EMISSIONS (TPY):	102,350 gallons No. 6 Fuel Oil with a Sulfur of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 6 FUEL OIL (TPY):	103,032 gallons No. 6 Fuel Oil with a Sulfur Content of 0.7% by weight	5.7
REDUCTION IN SO_2 EMISSONS (TPY):		6.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	5,691

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on actual installed cost of $170,000 for a similar storage tank installed in 1996..

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 6 fuel oil with a sulfur content of 0.7% ($0.6179/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 103,032 gallons per year.

Table 4-4. Cost Effectiveness of No. 2 Fuel Oil (0.5% Sulfur Content With New Tank and Burners) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	395,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	395,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator	$17/hr; 200 days/yr @ 8 hrs/day	0
Supervisor	15% of operator cost	0
(2) Maintenance		
Labor	Equivalent to Operating Labor	0
Materials	Equivalent to Maintenance Labor	0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.5% Sulfur Content)	See Footnote "e"	13,603
Total DOC:		13,603
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	3,950
Insurance	1% of total capital investment	3,950
Administration	2% of total capital investment	7,900
Total IOC:		15,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	64,267
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	93,670
BASELINE SO_2 EMISSIONS (TPY):	102,350 gallons No. 6 Fuel Oil with a Sulfur Content of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 2 FUEL OIL (TPY):	109,661 gallons No. 2 Fuel Oil with a Sulfur Content of 0.5% by weight	3.7
REDUCTION IN SO_2 EMISSONS (TPY):		8.9
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	10,525

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on an actual installed cost of $170,000 for a storage tank and a vendor quote of $225,000 for burner replacement (installed).

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.5% ($0.6607/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 109,661 gallons per year.

Table 4-5. Cost Effectiveness of No. 2 Fuel Oil (0.05% Sulfur Content With New Tank and Burners) for Boiler No. 4, U. S. Sugar Clewiston

Cost Items	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost[a]	See Footnote "b"	395,000
INDIRECT CAPITAL COSTS (ICC):[c]		
Indirect Installation Costs		
(a) Engineering	Based on Vendor Quote	Included Above
(b) Construction & Field Expenses	Based on Vendor Quote	Included Above
(c) Construction Contractor Fee	Based on Vendor Quote	Included Above
(d) Contingencies	Based on Vendor Quote	Included Above
Other Indirect Costs		
(a) Startup & Testing	Based on Vendor Quote	Included Above
(b) Working Capital	30-day DOC	Included Above
Total ICC:		Included Above
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	395,000
DIRECT OPERATING COSTS (DOC):[d]		
(1) Operating Labor		
Operator		0
Supervisor		0
(2) Maintenance		
Labor		0
Materials		0
(3) Utilities		
(4) Fuels		
No. 2 Fuel (0.05% Sulfur Content)	See Footnote "e"	18,994
Total DOC:		18,994
INDIRECT OPERATING COSTS (IOC):[d]		
Overhead	60% of oper. labor & maintenance	0
Property Taxes	1% of total capital investment	3,950
Insurance	1% of total capital investment	3,950
Administration	2% of total capital investment	7,900
Total IOC:		15,800
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1627 times TCI (10 yrs @ 10%)	64,267
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	99,061
BASELINE SO_2 EMISSIONS (TPY):	102,350 gallons No. 6 Fuel Oil with a Sulfur Content of 1.5% by weight	12.6
MAXIMUM SO_2 EMISSIONS WITH NO. 2 FUEL OIL (TPY):	113,722 gallons No. 2 Fuel Oil with a Sulfur Content of 0.05% by weight	0.4
REDUCTION IN SO_2 EMISSONS (TPY):		12.2
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	8,120

Footnotes:

[a] All direct installation costs are included in basic price.

[b] Based on an actual installed cost of $170,000 for a storage tank and a vendor quote of $225,000 for burner replacement (installed).

[c] All indirect installation costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 3.

[e] Increase in fuel cost associated with buying No. 2 fuel oil with a sulfur content of 0.05% ($0.6845/gal) instead of No. 6 fuel oil with a sulfur content 1.5% ($0.5750/gal) based on purchasing 113,723 gallons per year.

Table 4-6 Summary of the Cost Effectiveness of SO_2 Control Options

Description of Control Option	Annualized Cost ($/yr)	Maximum SO_2 Emission Rate (TPY)	Reduction in SO_2 Emission Rate[a] (TPY)	Cost Effectiveness ($/ton removed)
Replace No. 6 Fuel Oil (1.5% S) with No. 6 Fuel Oil (0.7% S) Stored in the Common Storage Tank	4,808	5.7	6.9	697
Replace No. 6 Fuel Oil (1.5% S) with No. 6 Fuel Oil (0.7% S) Stored in a New Storage Tank	39,267	5.7	6.9	5,691
Replace No. 6 Fuel Oil (1.5% S) with No. 2 Fuel Oil (0.5% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	93,670	3.7	8.9	10,525
Replace No. 6 Fuel Oil (1.5% S) with No. 2 Fuel Oil (0.05% S) Stored in a New Storage Tank and Replacement of Burners to Accommodate the New Fuel	99,061	0.4	12.2	8,120

Footnote:

[a] Based on a baseline SO_2 emission rate of 12.6 TPY.

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Table 2-1. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (revised 8/23/99)

Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceous Fuel			
Particulate Matter (PM)	0.15	1	633	600	95.0	90.0
Particulate Matter (PM10)	0.14	2	633	600	88.3	83.7
Sulfur dioxide	0.1	3	633	600	63.3	60.0
Nitrogen oxides	0.25	4	633	600	158.3	150.0
Carbon monoxide	6.5	1	633	600	4,114.5	3,900.0
VOC	0.5	5	633	600	316.5	300.0
Sulfuric Acid Mist	0.006	6	633	600	3.9	3.7
Lead	4.45E-04	7	633	600	0.28	0.27
Mercury	3.8E-05	8	633	600	0.0241	0.0228
Beryllium	--	7	633	600	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	225	--	22.5	22.5
Particulate Matter (PM10)	0.10	9	225	--	22.5	22.5
Sulfur dioxide (b)	2.73	10	225	--	615.0	615.0
Nitrogen oxides	0.31	11	225	--	69.8	69.8
Carbon monoxide	0.033	11	225	--	7.5	7.5
VOC	0.0019	11	225	--	0.4	0.4
Sulfuric Acid Mist	0.044	6	225	--	9.9	9.9
Lead	1.01E-05	11	225	--	2.27E-03	2.27E-03
Mercury	7.53E-07	11	225	--	1.70E-04	1.70E-04
Beryllium	1.85E-07	11	225	--	4.17E-05	4.17E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			530	499	68.3	63.6
Particulate Matter (PM10)			530	499	65.1	60.7
Sulfur dioxide			530	499	645.6	642.4
Nitrogen oxides			530	499	146.2	138.2
Carbon monoxide			530	499	1,993.3	1,787.2
VOC			530	499	153.2	137.3
Sulfuric Acid Mist			530	499	11.8	11.6
Lead			530	499	0.14	0.12
Mercury			530	499	0.012	0.011
Beryllium			530	499	4.17E-05	4.17E-05
			Maximum Any Combination			
Particulate Matter (PM)					95.0	90.0
Particulate Matter (PM10)					88.3	83.7
Sulfur dioxide					645.6	642.4
Nitrogen oxides					158.3	150.0
Carbon monoxide					4,114.5	3,900.0
VOC					316.5	300.0
Sulfuric Acid Mist					11.8	11.6
Lead					0.28	0.27
Mercury					0.0241	0.0228
Beryllium					4.17E-05	4.17E-05

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 300,000 lb/hr at 600 psig, 750 F.
Maximum 6-hour average activity factor based on steam production rate of 285,000 lb/hr at 600 psig, 750 F.
Enthalpy of steam = 1,378 Btu/lb. Enthalpy of feedwater = 218 Btu/lb. Net enthalpy = 1,160 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (300,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 168 MMBtu/hr
Required heat input to boiler from bagasse = 168 MMBtu/hr / 55% eff. = 305.5 MMBtu/hr
Total heat input required = 225 + 305.5 = 530 MMBtu/hr
Max 24-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (285,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 150.6 MMBtu/hr
Required heat input to boiler from bagasse = 150.6 MMBtu/hr / 55% eff. = 273.8 MMBtu/hr
Total heat input required = 225 + 274 = 499 MMBtu/hr

(b) The SO2 emission factor reflects the maximum sulfur content (2.5%) which could exist in the common plant No. 6 fuel oil tank. Boiler Nos. 1, 2 and 3 are permitted to burn up to 2.5% sulfur fuel oil, while the amount of fuel oil burned in Boiler No. 4 during a crop season will be replaced in the plant common fuel oil tank with fuel oil containing no more than 0.7% sulfur.

References

1. Current BACT permit limit for Clewiston.
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Proposed BACT limit, based on actual stack testing on Clewiston boilers. Equivalent to 0.1% sulfur content of bagasse (wet), 3,600 Btu/lb(wet); and 82% removal in wet scrubber.
4. Equivalent to current permit limit for Clewiston Boiler No. 4.
5. Proposed permit limit.
6. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
7. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
8. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
9. Assumed as 100% of PM emissions.
10. Based on 2.5% S fuel oil; 150,000 Btu/gal; 8.2 lb/gal; assumes 100% conversion of sulfur to SO2.
11. Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Multiple Fuel Combustion:
= {(Bagasse Activity Factor - Fuel Oil Activity Factor) x Bagasse Emission Factor}
+ (Fuel Oil Activity Factor x Fuel Oil Emission Factor)

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Table 2-2. Future Maximum Annual Emissions, Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	Bagasse Firing			Fuel Oil Firing			TOTAL EMISSIONS (TPY)
	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	
Particulate Matter (PM)	0.15 lb/MMBtu	2,880,000	216.0	0.1 lb/MMBtu	0	0.0	216.0
PM10	0.14 lb/MMBtu	2,880,000	201.6	0.1 lb/MMBtu	0	0.0	201.6
Sulfur Dioxide	0.1 lb/MMBtu	2,805,000	140.3	0.74 lb/MMBtu (b)	75,000	27.8	168.0
Nitrogen Oxides	0.25 lb/MMBtu	2,805,000	350.6	0.31 lb/MMBtu	75,000	11.6	362.3
Carbon Monoxide	6.5 lb/MMBtu	2,880,000	9,360.0	0.033 lb/MMBtu	0	0.0	9,360.0
Volatile Organic Compounds	0.5 lb/MMBtu	2,880,000	720.0	0.0019 lb/MMBtu	0	0.0	720.0
Sulfuric Acid Mist	0.006 lb/MMBtu	2,880,000	8.8	0.045 lb/MMBtu	0	0.0	8.8
Lead	4.45E-04 lb/MMBtu	2,880,000	0.6	1.01E-05 lb/MMBtu	0	0.0	0.64
Mercury	3.80E-05 lb/MMBtu	2,880,000	0.1	7.53E-07 lb/MMBtu	0	0.0	0.055
Beryllium	–	2,805,000	–	1.85E-07 lb/MMBtu	75,000	6.94E-06	6.94E-06

(a) Total heat input based on total steam production of 1.368E+09 lb steam/yr, 1,160 Btu/lb steam and 55% thermal efficiency.
Fuel oil considered where worst case emission factor is due to oil burning. Maximum fuel oil burning is 500,000 gal/yr, equivalent to 75,000 MMBtu/yr.

(b) Represents maximum sulfur content of 0.7% for fuel oil to be replaced in the plant common fuel oil tank.

References: Refer to Table 2-1 for emission factors.

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Table 3-3. Baseline Emissions for Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	Bagasse Firing				Fuel Oil Firing				TOTAL
	Emission Factor	Ref.	Heat Input (a) (MMBtu/yr)	Emissions (TPY)	Emission Factor	Ref.	Heat Input (b) (MMBtu/yr)	Emissions (TPY)	EMISSIONS (TPY)
Particulate Matter (PM)	0.12 lb/MMBtu	1	1,661,913	99.7	0.1 lb/MMBtu	4	15,816	0.79	100.5
PM10	0.112 lb/MMBtu	2	1,661,913	93.1	0.1 lb/MMBtu	9	15,816	0.79	93.9
Sulfur Dioxide	0.008 lb/MMBtu	1	1,661,913	6.6	1.67 lb/MMBtu	5	15,816	13.21	19.9
Nitrogen Oxides	0.082 lb/MMBtu	1	1,661,913	68.1	0.31 lb/MMBtu	10	15,816	2.45	70.6
Carbon Monoxide	6.36 lb/MMBtu	1	1,661,913	5,284.9	0.033 lb/MMBtu	10	15,816	0.26	5,285.1
Volatile Organic Compounds	0.25 lb/MMBtu	3	1,661,913	207.7	0.0019 lb/MMBtu	10	15,816	0.015	207.8
Sulfuric Acid Mist	0.00049 lb/MMBtu	6	1,661,913	0.4	0.10 lb/MMBtu	6	15,816	0.81	1.2
Lead	4.45E-04 lb/MMBtu	7	1,661,913	0.37	1.01E-05 lb/MMBtu	10	15,816	7.99E-05	0.37
Mercury	8.00E-06 lb/MMBtu	8	1,661,913	6.65E-03	7.53E-07 lb/MMBtu	10	15,816	5.95E-06	6.65E-03
Beryllium	--	7	1,661,913	0.0	1.85E-07 lb/MMBtu	10	15,816	1.46E-06	1.46E-06

(a) Based on actual steam production during 1997 and 1998, and actual steam enthalpies during stack tests.
(b) Based on average fuel oil usage during last two crop seasons of 90,686 gal (1997) and 119,395 gal (1998) and 151,000 Btu/gal

Footnotes:
(1) Based on average of stack tests from last 5 years.
(2) Based on 93% of PM emissions for bagasse burning based on limited testing of a bagasse boiler.
(3) Test data not available; assumed equal to permit limit of 1.7 lb/ton wet bagasse.
(4) Based on permit limit.
(5) Based on stoichiometric calculation of sulfur content (1.5 %) and density of No. 6 fuel oil (8.22 lb/gal).
(6) Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
(7) Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
(8) Based on average emission factor from stack testing of 5 bagasse boilers in Florida (refer to appendices).
(9) Assumed as 100% of PM emissions.
(10) Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Table 3-4. Net Emissions Increase for Clewiston Boiler No. 4, U.S. Sugar Corp. (revised 8/20/99)

Pollutant	PSD Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Applies?
Particulate Matter (PM)	100.5	216.0	115.5	25	Yes
PM10	93.9	201.6	107.7	15	Yes
Sulfur Dioxide	19.9	168.0	148.1	40	Yes
Nitrogen Oxides	70.6	362.3	291.7	40	Yes
Carbon Monoxide	5,285.1	9,360.0	4,074.9	100	Yes
Volatile Organic Compound	207.8	720.0	512.2	40	Yes
Sulfuric Acid Mist	1.2	8.8	7.6	7	Yes
Lead	0.37	0.64	0.27	0.6	No
Mercury	0.007	0.055	0.048	0.1	No
Beryllium	1.46E-06	6.94E-06	5.47E-06	4.00E-04	No

Table 1-1. Estimated Emissions for the Proposed Project (revised August 20, 1999)

	Boiler No. 4		Sugar Refinery		
Pollutant	Baseline Emissions (TPY)	Future Maximum Emissions (TPY)	Future Maximum Emissions (TPY)	Net Increase in Emissions (TPY)	PDS Significant Emission Rate (TPY)
PM	100.5	216.0	24.0	139.5	25
PM_{10}	93.9	201.6	24.0	131.7	15
SO_2	19.9	168.0	30.7	178.8	40
NO_x	70.6	362.3	8.8	300.5	40
CO	5285.1	9,360.0	7.8	4,082.7	100
VOC	207.8	720.0	20.1	532.3	40
Sulfuric Acid Mist	1.2	8.8	0	7.6	7
Lead	0.37	0.64	0	0.27	0.6
Mercury	0.007	0.055	0	0.048	0.1
Beryllium	0.0000015	0.0000069	0	0.0000055	0.0004

Emissions Unit Information Section 1 of 2 Boiler No.4

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **External combustion boilers; Industrial; Residual oil; Grade 6 oil**	
2. Source Classification Code (SCC): **1-02-004-01**	
3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.5**	5. Maximum Annual Rate: **500**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.7**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **150**	
10. Segment Comment (limit to 200 characters): **Max hourly and annual rates based on permit specific conditions.**	

Emissions Unit Information Section 1 of 2

Boiler No.4
Sulfur Dioxide

II. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 646.6 lb/hour 168.0 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ]1 [ ]2 [ ]3 _____ to _____ tons/yr
6. Emission Factor: 2.5 %S Reference: Fuel Sulfur Limit
7. Emissions Method Code: [ ]0 [ ]1 [ ]2 [ ]3 [ ]4 [X]5
8. Calculation of Emissions (limit to 600 characters): **See Tables 2-1 and 2-2. Note that the maximum hourly SO_2 emission reflect the assumption of 2.5-percent sulfur fuel oil burned from the plant common fuel oil tank.**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Max hourly emissions representative of combined carbonaceous fuel and fuel oil firing.**

Boiler No.4
Sulfur Dioxide

Emissions Unit Information Section 1 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 2.5 % Sulfur Oil	
4. Equivalent Allowable Emissions: 645.6 lb/hour	168.0 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 6 or 6C	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Applies to total combined carbonaceous fuel and fuel oil firing.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.1 lb/MMBtu	
4. Equivalent Allowable Emissions: 63.3 lb/hour	140.3 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 6 or 6C	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Applies to carbonaceous fuel firing only.	

Boiler No.4
Sulfur Dioxide

Emissions Unit Information Section 1 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER			
2. Future Effective Date of Allowable Emissions:			
3. Requested Allowable Emissions and Units: 2.5 %S fuel oil			
4. Equivalent Allowable Emissions:	615 lb/hour	27.8	tons/year
5. Method of Compliance (limit to 60 characters): Fuel Analysis			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on max heat input of 225 MMBtu/hr from fuel oil firing and assumes no removal in wet scrubber. Annual emission based on 500,000 gal/yr.			

B.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):		

Boiler No.4

Emissions Unit Information Section 1 of 2 Volatile Organic Compounds

II. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: VOC

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 316.5 lb/hour 720.0 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr

6. Emission Factor: 0.5 lb/MMBtu

Reference: Proposed Limit

7. Emissions Method Code:

[ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

8. Calculation of Emissions (limit to 600 characters):

See Tables 2-1 and 2-2

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Max emissions representative of carbonaceous fuel firing. Annual emissions based on heat input rate of 2,880,000 MMBtu/yr.

Boiler No.4

Emissions Unit Information Section 1 of 2 Volatile Organic Compounds

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.5 lb/MMBtu	
4. Equivalent Allowable Emissions: 316.5 lb/hour	720.0 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Murray Bunson, VP
US Sugar Corp
111 Ponce de Leon Ave
Clewiston, Fl
33440

4a. Article Number
Z 031 392 009

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
11.24.99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Andrea Sales

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Thank you for using Return Receipt Service.

Z 031 392 009

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murray Bunson	
Street & Number US Sugar	
Post Office, State, & ZIP Code Clewiston Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-22-99	

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