STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by: DEP File No. AC 26-238006
PSD-FL-208
Hendry County

Mr. Murray T. Brinson
Vice President, Sugar Processing
U. S. Sugar Corporation
P. O. Box 1207
Clewiston, Florida 33440

Enclosed is Permit Number AC 26-238006 (PSD-FL-208) for the construction of a 738 MMBtu/hr heat input (350,000 lbs/hr steam) boiler designed to burn bagasse and No. 2 fuel oil. The annual capacity factor (ACF) for No. 2 fuel oil is limited to 10%. Boiler No. 7 will be constructed/installed at the U.S. Sugar Corporation's existing sugar mill that is located near the intersection of W. C. Owens Avenue and Clewiston Street in Clewiston, Hendry County, Florida, issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; 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 of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 2/2/95 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J Hayes 2/2/95
(Clerk) (Date)

Copies furnished to:
- Jewell Harper, EPA
- John Bunyak, NPS
- David Knowles, SFD
- Robert VanVoorhees, Esquire
- David Buff, KBN

FINAL DETERMINATION

United States Sugar Corporation's application for a permit to construct a 738 MMBTU/hr at their facility in Clewiston, Hendry County, Florida has been reviewed by the Bureau of Air Regulation in Tallahassee. The Technical Evaluation and Preliminary Determination for the permit to construct a 738 MMBTU/hr heat input Boiler (No. 7) in Clewiston, Florida, was distributed on October 24, 1994. The Notice of the Intent was published in the Clewiston News on November 2, 1994. Copies of the evaluation were available for inspection at the Department's offices in Fort Myers and Tallahassee.

Comments regarding the Technical Evaluation and Preliminary Determination and Specific Conditions of the proposed permit were submitted by Mr. Stan Kukier from the U.S. Environmental Protection Agency, and Mr. Murray T. Brinson, Vice President of U.S. Sugar Corporation, in their letters of November 30, January 6, 1995 and November 3, 1994, respectively. The Bureau has considered Mr. Kukier and Mr. Brinson comments and has agreed to the changes proposed for the material covered by the paragraphs "Background Information", "Project Description" and "Control Technology Review".

The revisions of the specific conditions of the permit are finalized as follows:

DEP PERMIT NUMBER AC 26-238006, PSD-FL-208 For a 738 MMBtu/hr Boiler No. 7.

EPA COMMENT - SPECIFIC CONDITION NO. 1

Based on EPA's comments regarding PSD applicability, the Department concurs with the revised net emission calculations presented by EPA. The draft permit, Table 2 of the Technical Evaluation and BACT documents will be revised to include the net emissions changes and new emissions standard for particulate matter. U. S. Sugar Corporation prepared PM impact analyses, which included air dispersion modeling, as part of the Clewiston Boiler No. 7 construction permit application. Tables 4, 5, and 6 in the technical evaluation and preliminary determination for this project have been updated to include the modeling results of these analyses. Additionally, the PM_{10} background concentrations in Table 6 are based on data collected from Florida Sugar Cane League (FSCL) PM_{10} monitors during the period 1988-1991. As shown in these three tables all PM_{10} impacts are predicted to be less than the applicable standards and increments.

Specific Condition No. 1 will be revised as follows:

FROM:

EMISSION LIMITATIONS

1. Based on a maximum heat input to the boiler of 738 MMBtu/hr for bagasse and 250 MMBtu/hr for fuel oil, stack emissions shall not exceed the following limits:

ALLOWABLE EMISSIONS

Pollutant	Bagasse			No. 2 Fuel Oil		
	lb/MMBtu	lbs/hr	tons/yr	lb/MMBtu	lbs/hr	tons/yr
Particulate Matter (PM)	0.04	30	129	0.04	10	12.88
PM_{10}	0.035	26	112	0.04	10	12.88
Sulfur Dioxide	0.17	125	550	0.05	12.5	16.10
Nitrogen Oxides	0.25	185	809	0.2	50.0	64.40
Carbon Monoxide	0.70	516	2,262	0.066	16.5	21.25
Volatile Organic Compounds	0.212	157	685	0.004	1.0	1.29
Sulfuric Acid Mist	0.017	13	55	0.005	1.25	1.60

TO:

EMISSION LIMITATIONS

1. Based on a maximum heat input to the boiler of 738 MMBtu/hr for bagasse and 250 MMBtu/hr for fuel oil, stack emissions shall not exceed the following limits:

ALLOWABLE EMISSIONS

Pollutant	Bagasse			No. 2 Fuel Oil		
	lb/MMBtu	lbs/hr	tons/yr	lb/MMBtu	lbs/hr	tons/yr
Particulate Matter (PM)	0.03	**22**	**97**	0.03	**7.5**	**9.7**
PM_{10}	0.03	**22**	**97**	0.03	**7.5**	**9.7**
Sulfur Dioxide	0.17	125	550	0.05	12.5	16.10
Nitrogen Oxides	0.25	185	809	0.2	50.0	64.40
Carbon Monoxide	0.70	516	2,262	0.066	16.5	21.25
Volatile Organic Compounds	0.212	157	685	0.004	1.0	1.29
Sulfuric Acid Mist	0.017	13	55	0.005	1.25	1.60

A. U.S. SUGAR COMMENTS

A. EXPIRATION DATE - U.S. Sugar Corporation has requested an expiration date of March 31, 1998 rather than September 1, 1996. They have anticipated that Boiler No. 7 will be operated only during the sugar cane processing crop season, which falls between October 1 and March 31. U.S. Sugar Corporation does not anticipate that actual construction work on the boiler will be completed very much in advance of December 31, 1996. Initial startup and debugging work will proceed for the remainder of the 1996-97 crop season and may be completed by March 31, 1997. This means that operation to achieve full capacity will not begin until the start of the 1997-98 crop season in October 1997. Full commissioning of the boiler, including compliance testing will proceed during the 1997-98 crop season and be completed by March 31, 1998. Under no circumstances will this boiler be fully constructed, commissioned and tested by September 1, 1996.

DEP RESPONSE:

Provide that this emission unit will be timely tested as specified in Specific Condition No. 14; the expiration date of this permit will be changed as follows:

FROM: September 1, 1996.

TO: March 31, 1998.

B. SPECIFIC CONDITION NO. 11:

U.S. SUGAR COMMENT - The second sentence should be deleted from Specific Condition 11. The limitation placed on the use of the boiler in that sentence exceeds the restriction set forth in the regulations cited as authority for the limitation. The regulations in 40 CFR Part 60, Subpart Da do not prohibit the sale of electricity generated by an industrial boiler to any utility power distribution system at the levels specified in the second sentence. 40 CFR 60.41a simply states that any boiler <u>constructed for the purpose</u> of providing more than one-third of its potential electric output capacity <u>and more than 25 MW</u> to any utility power distribution system is subject to the New Source Performance Standards for electric utility boilers. The question is one of intended use at the time of permitting. U.S. Sugar Corporation has no intention to use the boiler to supply electricity to any utility power distribution systems at levels that exceed these criteria. Moreover, to exceed the criteria, it would be necessary for U.S. Sugar to be planning to supply more than 25 MW, or more than 70% of the potential electric output capacity of the boiler since the criterion is two-fold and conjunctive.

DEP RESPONSE:

The intent of Specific Condition No. 11 is to provide the Department with reasonable assurance that a 250 million Btu/hour fossil fuel boiler (Boiler No. 7) will not be an affected facility under 40 CFR 60.41a. The revised specific condition will satisfy the Department's concern on this issue. U.S. Sugar Corporation, as confirmed in their November 3, 1994, letter, has no intent to use Boiler No. 7 to supply electricity to any utility power distribution system at levels specified in the applicable definition for electrical utility steam generating unit, 40 CFR 60.41a. This specific condition is revised as follows:

FROM:

11. The fuel oil system for Boiler No. 7 shall be designed, constructed, and operated so that it cannot exceed the fuel feed rate equivalent to or greater than 250 MMBtu/hr heat input (high heating value of the fuel oil, 1-hour average). Not more than 1/3 of the potential electric output capacity and not more than 25 MW electricity output shall be supplied to any utility power distribution system for sale. The permittee shall maintain records of the hourly fuel oil feed rate to the boiler, the percentage of electrical power output distributed to any utility power distribution system, and the amount of electrical power (MW) distributed to any utility power distribution system (40 CFR 60, Subpart Da).

TO:

11. The fuel oil system for Boiler No. 7 shall be designed, constructed, and operated so that it cannot exceed the **fossil** fuel feed rate equivalent to or greater than 250 MMBtu/hr heat input (high heating value of the fuel oil, 1-hour average). The permittee shall maintain records of the hourly fuel oil feed rate to the boiler, the percentage of electrical power output distributed to any utility power distribution system, and the amount of electrical power (MW) distributed to any utility power distribution system (40 CFR 60, Subpart Da).

C. SPECIFIC CONDITION NO. 14:

U.S. SUGAR COMMENT - Specific Condition No. 14 should be revised to provide that stack tests be performed "no later than 180 operating days after initial (I) startup." It is necessary to state this requirement in terms of operating days because U.S. Sugar operates its boilers on a seasonal basis only during the sugar cane crop harvesting season. Initially, Boiler No. 7 will also be operated on a seasonal basis. Thus, it is quite possible that the boiler will be started up during the latter portion of the 1996-97 crop season, but will not achieve maximum capacity until sometime during the 1997-98 crop season. To allow for this contingency, the 180-day requirement should be stated in terms of operating days.

RESPONSE:

This specific condition will be modified to include EPA's guidance regarding this issue. The intent of the Federal Regulations, 40 CFR 52.12(c)(1), Source Surveillance and 40 CFR 60.8 Performance Tests, is for the emission unit to be tested "within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start up of such facility.." Although, the word

"calendar" is not included in the above federal regulation, it is EPA's and DEP's intent to consider **calendar** days for purpose of achieving timely compliance. However, for this facility according to EPA's memo of September 29, 1977, from E. Reich to J. Wilbur, if the emission unit has not been performance tested in the 180 day period following start up due to subsequent long term shutdown, the permittee is required to notify the Department upon restartup (by telephone; to be followed by confirmation in writing) and to perform a compliance test as soon as practicable thereafter but no later than 30 days after restartup.

Specific Condition No. 14 will be revised as follows:

FROM:

14. Performance Stack Tests. Within 60 calendar days after achieving the maximum capacity at which this unit will be operated, but no later than 180 days after initial (I) startup and annually (A) thereafter, the permittee shall conduct performance tests for: sulfur dioxide (I and upon permit renewal), sulfuric acid mist (I), particulate matter (I,A), nitrogen oxides (I,A), volatile organic compounds (I,A), and carbon monoxide (I,A) while burning bagasse. The performance tests shall be conducted in accordance with the provisions of 40 CFR 60.45b and 60.46b. Testing of emissions shall be conducted with the emission unit operating at permitted capacity. Permitted capacity is defined as 90-100% of the maximum operating rate allowed by the permit. If it is impracticable to test at permitted capacity, then Boiler No. 7 may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once Boiler No. 7 is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for the purposes of additional compliance testing to regain the permitted capacity in the permit. Results of the tests shall be submitted to the Department's South Florida District office within 45 days after testing. The Department's South Florida District office shall be notified 30 days prior to any compliance test to allow witnessing.

The EPA Reference Methods shall be performed in accordance with 40 CFR Part 60 (Standards of Performance for New Stationary Sources), Appendix A, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), Appendix B. No other test method may be used until authorization has been obtained in writing from the Department. An alternate sampling procedure can be requested in accordance with Chapter 62-297, F.A.C. A test protocol shall be submitted for approval to the Department's Bureau of Air Regulation at least 90 days prior to testing.

TO:

14. Performance Stack Tests. Within 60 calendar days after achieving the maximum capacity at which this unit will be operated, but no later than 180 days after initial (I) startup and annually

(A) thereafter, the permittee shall conduct performance tests for: sulfur dioxide (I and upon permit renewal), sulfuric acid mist (I), particulate matter (I,A), nitrogen oxides (I,A), volatile organic compounds (I,A), and carbon monoxide (I,A) while burning bagasse. The performance tests shall be conducted in accordance with the provisions of 40 CFR 60.45b and 60.46b. **If Boiler No. 7 is unable to conduct the initial performance test due to long term shutdown, the permittee is required to notify the Department within the specified time frames above upon restartup (by telephone: to be followed by confirmation in writing) and also to conduct a performance test as soon as practicable thereafter but not later than 30 days after restartup.** Testing of emissions shall be conducted with the emission unit operating at permitted capacity. Permitted capacity is defined as 90-100% of the maximum operating rate allowed by the permit. If it is impracticable to test at permitted capacity, then Boiler No. 7 may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once Boiler No. 7 is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for the purposes of additional compliance testing to regain the permitted capacity in the permit. Results of the tests shall be submitted to the Department's South Florida District office within 45 days after testing. The Department's South Florida District office shall be notified 30 days prior to any compliance test to allow witnessing.

The EPA Reference Methods shall be performed in accordance with 40 CFR Part 60 (Standards of Performance for New Stationary Sources), Appendix A, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), Appendix B. No other test method may be used until authorization has been obtained in writing from the Department. An alternate sampling procedure can be requested in accordance with Chapter 62-297, F.A.C. A test protocol shall be submitted for approval to the Department's Bureau of Air Regulation at least 90 days prior to testing.

D. SPECIFIC CONDITION NO. 18:

U.S. SUGAR COMMENT - Specific Condition No. 18 should be revised to read as follows:

"Visible emission from the bagasse handling systems shall not exceed 10 percent opacity over any 6 minute period as measured by EPA Reference Method 9, provided, however, that this visible emissions limit shall not apply during periods of high winds (wind speed of 18 miles per hour or greater) if reasonable precautions (covered conveyors, windbreaks, and the height of drop points are minimized) to control fugitive emissions have been taken. The company shall maintain a meteorological instrument to record the wind speed at the plant which shall be located at its Research Center, about one mile "south" of the Clewiston Mill.

DEP RESPONSE:

The Department feels that reasonable precautions as it will be listed in the new condition No. 18 will be sufficient to address the bagasse handling operation. No numerical visible emissions standard will be set.

This condition will be revised as follows:

FROM:

18. Visible emissions from the bagasse handling systems shall not exceed 10% opacity over any 6-minute period as measured by EPA Reference Method 9. Reasonable precautions shall be used to minimize fugitive emissions when reclaiming dry bagasse for the boiler. The permittee shall maintain a meteorological instrument to record the wind speed at the plant, which shall be located at its Research Center located about one mile "south" of the Clewiston mill.

TO:

Pursuant to Rule 62.296.310(3) F.A.C., reasonable precautions shall be used to minimize unconfined emissions of particulate matter when reclaiming dry bagasse for the boiler. Reasonable precautions may include, but shall not be limited to the following:

1) Paving and maintenance of road, parking areas and yards.
2) Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
3) Application of asphalt, water, oil, chemicals or dust suppressants to unpaved road, yards, open stock piles and similar sources.
4) Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the source to prevent reetrainment, and from building or work areas to prevent particulate from becoming airborne.
5) Landscaping or planting of vegetation.
6) Use of hoods, capture and/or vent particulate matter.
7) Confining abrasive blasting where possible.
8) Enclosure or covering of conveyor systems.
9) Wind breaks shall be installed around the dry bagasse load-out area.
10) Floors in the enclosed area shall be cleaned periodically.
11) Loading areas for bagasse shall be cleaned or wetted as needed to minimize fugitive dust.
12) Trucks transporting bagasse shall be covered.

DEP COMMENTS -

Specific Conditions No. 9 and 12 will be revised for clarification purposes.

SPECIFIC CONDITION No. 9:

This condition will be revised as follows:

FROM:

9. During any calendar year, the maximum quantity of No. 2 fuel oil (maximum 0.05% S content, by weight) burned in Boiler No. 7 shall not exceed 4,600,000 gallons. The consumption of fuel oil shall not exceed 10% of the maximum potential heat input to the boiler in any calendar year.

TO:

9. During any calendar year, the maximum quantity of No. 2 fuel oil (maximum 0.05% S content, by weight) burned in Boiler No. 7 shall not exceed 4,600,000 gallons. **The annual capacity factor (ACF) for No. 2 fuel oil is limited to 10%.**

The permittee shall install, calibrate, maintain and operate a continuous monitoring device for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The monitoring device shall meet the applicable requirements of Section 62-297.500, F.A.C., and 40 CFR 60 Subpart Db.

DEP COMMENTS - SPECIFIC CONDITION NO. 12:

FROM:

12. Boilers No. 5 and No. 6 may be retained as standby boilers at the Clewiston Mill. Boilers No. 5 and No. 6 may be operated during initial start-up, debugging, and testing of Boiler No. 7. After Boiler No. 7 becomes operational, Boilers No. 5 and No. 6 may be operated only when one or more boilers of equal or greater permitted heat input at the Clewiston Mill are shut down. During operation, Boilers No. 5 and No. 6 must comply with all requirements in their current operating permits. The operation permits for Boilers No. 5 and No. 6 shall be amended to reflect this condition.

TO:

12. Boilers No. 5 and No. 6 may be retained as standby boilers at the Clewiston Mill. Boilers No. 5 and No. 6 may be operated during initial start-up, debugging, and testing of Boiler No. 7. After Boiler No. 7 becomes operational, Boilers No. 5 and No. 6 may be operated only when one or more boilers of equal or greater permitted heat input, **and with equal to or greater allowable emissions**, at the Clewiston Mill are shut down. During operation,

Boilers No. 5 and No. 6 must comply with all requirements in their current operating permits. The operation permits for Boilers No. 5 and No. 6 shall be amended to reflect this condition. **The permittee shall maintain records of actual operation of all boilers at the Clewiston Mill for at least a five (5) year period.**

The final action of the Department is to issue construction permits AC26-238006 and PSD-FL-208 with the changes noted above.

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
U.S. Sugar Corporation
P. O. Box 1207
Clewiston, Florida 33440

Permit Number: AC26-238006
PSD-FL-208
Expiration Date: September 1, 1996
County: Hendry
Latitude/Longitude: 26°44'05"N
80°56'20"W
Project: Boiler No. 7

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-210 through 62-297 and 62-4, Florida Administrative Code (F.A.C.); and, 40 CFR 52.21. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and specifically described as follows:

Construction of a 738 MMBtu/hr heat input (350,000 lbs/hr steam) boiler designed to burn bagasse and No. 2 fuel oil. The annual capacity factor (ACF) for No. 2 fuel oil is limited to 10%. Boiler No. 7 will be constructed/installed at the U.S. Sugar Corporation's existing sugar mill that is located near the intersection of W. C. Owens Avenue and Clewiston Street in Clewiston, Hendry County, Florida. The UTM coordinates of this site are 17-506.1 km East and 2956.9 km North.

The emissions unit shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below</u>:

1. Application received September 17, 1993.
2. Department's letter dated October 15, 1993.
3. U.S. Sugar Corporation's letter dated December 22, 1993.
4. U.S. Sugar Corporation's letter dated February 22, 1994.
5. Department's letter dated February 28, 1994.
6. Department's letter dated March 18, 1994.
7. U.S. Sugar Corporation's (ICF Kaiser) letter dated May 10, 1994.
8. U.S. Sugar Corporation's (Bryan Cave's) letter dated June 7, 1994.
9. U.S. Sugar Corporation's letter dated June 29, 1994.
10. United States Department of Interior's letter dated June 28, 1994.
11. Bryan Cave's letter dated July 13, 1994.
12. Bryan Cave's letter dated July 28, 1994.
13. Bryan Cave's letter dated Septeber 9, 1994.
14. KBN's letter dated September 23, 1994.

15. U.S. Sugar Corporation's letter dated September 28, 1994.
16. EPA's letter dated October 27, 1994.
17. U.S. Sugar Corporation's letter dated November 9, 1994.
18. U.S. Sugar Corporation's letter dated November 3, 1994.
19. EPA' sletter dated November 30, 1994.
20. Bryan Cave's letter dated December 15, 1994.
21. KBN's letter dated December 8, 1994.
22. EPA's letter dated January 6, 1994.

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. a description of and cause of non-compliance; and,

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

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

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

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

GENERAL CONDITIONS:

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

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

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;
        - the analytical techniques or methods used; and,
        - the results of such analyses.

GENERAL CONDITIONS:

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.

SPECIFIC CONDITIONS:

EMISSION LIMITATIONS

1. Based on a maximum heat input to the boiler of 738 MMBtu/hr for bagasse and 250 MMBtu/hr for fuel oil, stack emissions shall not exceed the following limits:

ALLOWABLE EMISSIONS

Pollutant	Bagasse			No. 2 Fuel Oil		
	lb/MMBtu	lbs/hr	tons/yr	lb/MMBtu	lbs/hr	tons/yr
Particulate Matter (PM)	0.03	22	97	0.03	7.5	9.7
PM_{10}	0.03	22	97	0.03	7.5	9.7
Sulfur Dioxide	0.17	125	550	0.05	12.5	16.10
Nitrogen Oxides	0.25	185	809	0.2	50.0	64.40
Carbon Monoxide	0.70	516	2,262	0.066	16.5	21.25
Volatile Organic Compounds	0.212	157	685	0.004	1.0	1.29
Sulfuric Acid Mist	0.017	13	55	0.005	1.25	1.60

CONSTRUCTION AND OPERATIONAL REQUIREMENTS

2. Construction of Boiler No. 7 shall conform to the plans described in the application.

3. The boiler shall be of the spreader-stroker vibrating-grate type.

4. The boiler's stack shall have a minimum height of 225 feet. After Boiler No. 7 becomes operational, Boilers Nos. 1, 2, and 3 stacks shall have a minimum height of 150 feet. The stack sampling facilities for each stack shall comply with Rule 62-297.345, F.A.C.

5. The boiler shall be equipped with instruments to measure fuel oil flowrate, steam production, steam pressure, and steam temperature.

SPECIFIC CONDITIONS:

6. The boiler shall be equipped with an electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

The permittee shall submit to the Department copies of technical data pertaining to the selected ESP and to the boiler design within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency, emission rate and major design parameters.

Nitrogen oxides emissions will be controlled by overfire air and good combustion practices; and, will be minimized using low-nitrogen fuel oil (max. 0.015% N content, by weight). Carbon monoxide and volatile organic emissions will be controlled by good combustion practices. Sulfur dioxide and sulfuric acid mist emissions, when firing fuel oil, will be controlled by using very low-sulfur No. 2 fuel oil (max. 0.05% S content, by weight).

7. Boiler No. 7 shall be operated in accordance with the capabilities and specifications described in the application. Steam production, heat input, and bagasse consumption shall not exceed the following:

Steam Pressure psig	Steam Temp. F°	Averaging Time	Steam Production lbs/hr	Heat Input MMBtu/hr	Bagasse Feedrate lbs/hr-wet
600	750	1-hr max. Max. 24-hr avg.	385,000 350,000	812 738	203,060 184,600

8. Heat input from No. 2 fuel oil (0.05% S content, by weight) shall not exceed 250 MMBtu/hr (which is approximately equivalent to 1,785 gallons per hour of oil and 175,000 pounds per hour of steam). The boiler shall be operated so that not more than two burners with two oil guns each (total of four oil guns) can be used with a total maximum capacity not to exceed the permitted fuel oil input rate.

9. During any calendar year, the maximum quantity of No. 2 fuel oil (maximum 0.05% S content, by weight) burned in Boiler No. 7 shall not exceed 4,600,000 gallons. The annual capacity factor (ACF) for No. 2 fuel oil is limited to 10%.

The permittee shall install, calibrate, maintain and operate a continuous monitoring device for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The monitoring device shall meet the applicable requirements of Section 62-297.500, F.A.C., and 40 CFR 60, Subpart Db.

SPECIFIC CONDITIONS:

10. All stationary fuel-oil burning equipment at the plant shall be equipped with integrating fuel oil flow meters or continuous recorders to measure the amount of fuel oil consumed by the equipment. Fuel oil meter readings on all fuel oil consuming equipment shall be read and logged at least once every three hours, unless fuel oil consumption for the equipment is recorded continuously, and these records shall be kept for at least five years for Department inspection. Each meter shall be calibrated annually by a method approved by the Department.

11. The fuel oil system for Boiler No. 7 shall be designed, constructed, and operated so that it cannot exceed the fossil fuel feed rate equivalent to or greater than 250 MMBtu/hr heat input (high heating value of the fuel oil, 1-hour average). The permittee shall maintain records of the hourly fuel oil feed rate to the boiler, the percentage of electrical power output distributed to any utility power distribution system, and the amount of electrical power (MW) distributed to any utility power distribution system (40 CFR 60, Subpart Da).

12. Boilers No. 5 and No. 6 may be retained as standby boilers at the Clewiston Mill. Boilers No. 5 and No. 6 may be operated during initial start-up, debugging, and testing of Boiler No. 7. After Boiler No. 7 becomes operational, Boilers No. 5 and No. 6 may be operated only when one or more boilers of equal or greater permitted heat input, and with equal to or greater allowable emissions at the Clewiston Mill are shut down. During operation, Boilers No. 5 and No. 6 must comply with all requirements in their current operating permits. The operation permits for Boilers No. 5 and No. 6 shall be amended to reflect this condition. The permittee shall maintain records of actual operation of all boilers a the Clewiston Mill for at least a five (5) year period.

13. Prior to operation of the emissions unit, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor the emissions control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

COMPLIANCE REQUIREMENTS

14. Performance Stack Tests. Within 60 calendar days after achieving the maximum capacity at which this unit will be operated, but no later than 180 days after initial (I) startup and annually (A) thereafter, the permittee shall conduct performance tests for: sulfur dioxide (I and upon permit renewal), sulfuric acid mist (I), particulate matter (I,A), nitrogen oxides (I,A), volatile organic compounds (I,A), and carbon monoxide (I,A) while burning bagasse. The performance tests shall be conducted in accordance with the provisions of 40 CFR 60.45b and 60.46b. If Boiler No. 7 is unable

SPECIFIC CONDITIONS:

to conduct the initial performance test due to long term shutdown, the permittee is required to notify the Department within the specified time frames above upon restartup (by telephone: to be followed by confirmation in writing) and also to conduct a performance test as soon as practicable thereafter but not later than 30 days after restartup. Testing of emissions shall be conducted with the emission unit operating at permitted capacity. Permitted capacity is defined as 90-100% of the maximum operating rate allowed by the permit. If it is impracticable to test at permitted capacity, then Boiler No. 7 may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once Boiler No. 7 is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for the purposes of additional compliance testing to regain the permitted capacity in the permit. Results of the tests shall be submitted to the Department's South Florida District office within 45 days after testing. The Department's South Florida District office shall be notified 30 days prior to any compliance test to allow witnessing.

The EPA Reference Methods shall be performed in accordance with 40 CFR Part 60 (Standards of Performance for New Stationary Sources), Appendix A, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), Appendix B. No other test method may be used until authorization has been obtained in writing from the Department. An alternate sampling procedure can be requested in accordance with Chapter 62-297, F.A.C. A test protocol shall be submitted for approval to the Department's Bureau of Air Regulation at least 90 days prior to testing.

15. <u>Particulate matter (PM/PM_{10}) emissions</u> from Boiler No. 7 shall not exceed 0.03 lb/million Btu heat input for all fuels. Compliance with the PM and PM_{10} standards shall be determined by EPA Reference Methods 1, 2, 3 or 3A, 4, 5 or 17, respectively, in accordance with 40 CFR 60, Appendix A. The compliance test results shall be calculated by assuming the thermal efficiency of Boiler No. 7 to be 55%. For information purposes only, the particulate matter emission rates shall also be calculated by utilizing the short-form ASME boiler-efficiency test results (once every five years: required for the initial operation permit and to be on the same schedule as the operation permit).

16. <u>Unconfined Particulate Matter emissions</u> during land clearing and site preparation shall be minimized using wetting operations or other soil treatment techniques appropriate for controlling unconfined particulate matter emissions including, but not limited to, grass seedings and mulching of disturbed areas. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations.

SPECIFIC CONDITIONS:

17. Visible emissions from Boiler No. 7 shall not exceed 20% opacity, except that 27% opacity is allowed for 6-minutes during any 1-hour period. Compliance with the standard shall be determined using EPA Reference Method 9 pursuant to Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. The particulate matter emissions and visible emissions tests shall be determined concurrently. Under circumstances when this is not feasible, the company shall obtain approval from the Department's South Florida District to conduct the tests at separate times.

In such circumstances, the tests shall be conducted as close to each other as is feasible. In accordance with 40 CFR 60.486 the permittee shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions. The monitoring device shall meet the applicable requirements under Chapter 62-297, F.A.C., and 40 CFR 60, Appendix B.

18. Pursuant to Rule 62.296.310(3) F.A.C., reasonable precautions shall be used to minimize unconfined emissions of particulate matter when reclaiming dry bagasse for the boiler. Reasonable precautions may include, but shall not be limited to the following:

1) Paving and maintenance of road, parking areas and yards.
2) Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
3) Application of asphalt, water, oil, chemicals or dust suppressants to unpaved road, yards, open stock piles and similar sources.
4) Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the source to prevent reetrainment, and from building or work areas to prevent particulate from becoming airborne.
5) Landscaping or planting of vegetation.
6) Use of hoods, capture and/or vent particulate matter.
7) Confining abrasive blasting where possible.
8) Enclosure or covering of conveyor systems.
9) Wind breaks shall be installed around the dry bagasse load-out area.
10) Floors in the enclosed area shall be cleaned periodically.
11) Loading areas for bagasse shall be cleaned or wetted as needed to minimize fugitive dust.
12) Trucks transporting bagasse shall be covered.

SPECIFIC CONDITIONS:

19. No. 2 fuel oil burned in this boiler shall contain no more than 0.05% sulfur content, by weight. Compliance with this condition shall be determined from certified analyses of the oil by ASTM Method D-129, D-1552, D-2622 or D-4294, by the fuel supplier or the permittee. Records of the quantity and analysis of fuel oil consumed in Boiler No. 7 and invoices for the fuel oil purchases shall be kept for a minimum of five years for regulatory agency inspection.

20. Sulfur dioxide emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.17 lb/million Btu heat input, as determined by EPA Reference Method 6 and in accordance with 40 CFR 60, Appendix A. Sulfuric acid mist emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.017 lb/Million Btu heat input as determined by EPA Reference Method 8 and in accordance with 40 CFR 60, Appendix A.

21. Nitrogen oxides emissions, expressed as NO_2, shall not exceed 185 lbs/hr as determined by EPA Reference Method 7 and in accordance with 40 CFR 60, Appendix A. The fuel oil shall contain no more than 0.015% nitrogen content, by weight, as determined using ASTM D4629.

22. Carbon monoxide and volatile organic compounds emissions shall be maintained at the lowest possible level through the implementation of an Operation and Maintenance plan that has been approved by the Department. Emissions of carbon monoxide shall not exceed 0.70 lb/million Btu as determined by EPA Method 10 and in accordance with 40 CFR 60, Appendix A. Emissions of nonmethane volatile organic compounds shall not exceed 1.7 lb/ton of wet bagasse or 0.21 lb/MMBtu as determined by EPA Method 25 or 25A in conjunction with EPA Method 18 and in accordance with 40 CFR 60, Appendix A.

23. Thermal efficiency. A test shall be conducted on Boiler No. 7 to determine its actual thermal efficiency in accordance with the ASME short-form procedure each time the operating permit for this boiler is renewed. The test shall be done while the tubes are clean and within 14 days of the compliance test, unless an alternative schedule is approved by the Department. A current report on the thermal efficiency tests must be included with the application to operate this boiler.

REPORTING REQUIREMENTS

24. Fuel usage, fuel analysis data, and sulfur dioxide emissions calculations for fuel oil combustion shall be reported to the

SPECIFIC CONDITIONS:

Department's South District Office on a quarterly basis commencing with the start of full-time operation in accordance with 40 CFR 60, Sections 60.7 and 60.49b.

RULE REQUIREMENTS

25. This emissions unit shall comply with all applicable provisions of Chapter 403, F.S.; Chapter 62-4 and Chapters 62-210 through 297, F.A.C.; 40 CFR 60; and, applicable requirements of 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

26. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62.210.300(1), F.A.C.).

27. This source shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS) Subpart Db; Rule 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation Problems.

28. Pursuant to Rule 62-210.370(2), F.A.C., Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual reports shall be sent to the Department's South Florida District office.

29. The permittee shall install permanent stack sampling facilities in accordance with Rule 62-297.345, F.A.C.

30. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

31. An application for an operation permit must be submitted to the Department's South District office at least 90 days prior to the expiration date of this construction permit or within 45 days after completion of compliance testing, whichever occurs first. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that

PERMITTEE:
U.S. Sugar Corporation

Permit Number: AC26-238006
PSD-FL-208
Expiration Date: September 1, 1996

SPECIFIC CONDITIONS:

construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.220, and 17-4.055, F.A.C.).

Issued this 31st day
of January, 1995

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Department of Environmental
Protection

Table 1. Allowable Emissions

Pollutant	Bagasse			No. 2 Fuel Oil		
	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr
Particulate (PM)	0.03	22	97	0.03	7.5	9.7
Particulate (PM_{10})	0.03	22	97	0.03	7.5	9.7
Sulfur Dioxide[1]	0.17	125	550	0.05	12.5	16.10
Nitrogen Oxides[2]	0.25	185	809	0.2	50.0	64.40
Carbon Monoxide	0.70	516	2,262	0.066	16.5	21.25
Volatile Organic Compounds	0.212	157	685	0.004	1.0	1.29
Sulfuric Acid Mist	0.017	13	55	0.005	1.25	1.60
Lead				56E-06		
Mercury				6.4E-06		
Beryllium				8.4E-06		
Fluorides				12.6E-06		

[1] Compliance based on use of very-low sulfur fuel oil (0.05% sulfur) and on 24-hour rolling average per 40 CFR 60. Subpart Db

[2] Compliance based on use of low nitrogen fuel oil and on 24-hour rolling average per 40 CFR 60, Subpart Db

Table 2. Revised PSD Source Applicability for U.S. Sugar Clewiston Boiler No.7

Regulated Pollutant	Contemporaneous Decreases (TPY) Boiler 5	Boiler 6	Total	Increase Due to Boiler No.7 (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	27.2	33.1	60.3	97[a]	36.7	25	Yes
Particulate(PM10)	24.5	29.8	54.3	97[b]	42.7	15	Yes
Sulfur dioxide	11.1	12.3	23.5	549.5	526.05	40	Yes
Nitrogen oxides	26.4	29.6	56.1	808.1[c]	752.05	40	Yes
Carbon monoxide	1,180.1	1,323.7	2,503.8	2,262.7[d]	-241.1	100	No
Volatile Org.Compds.	44.0	49.4	93.4	685.3	591.85	40	Yes
Lead	-	-	-	0.018	0.018	0.6	No
Mercury	-	-	-	0.0021	0.0021	0.1	No
Beryllium	-	-	-	0.0027	0.0027	0.0004	Yes
Fluorides	-	-	-	0.0041	0.0041	3	No
Sulfuric acid mist [b]	1.1	1.2	2.35	55.0[e]	52.6	7	Yes
Total reduced sulfur	-	-	-	-	-	10	No
Asbestos	-	-	-	-	-	0.007	No
Vinyl Chloride	-	-	-	-	-	0	No

[a] Based on PM emission limit of 0.03 lb/MMBtu.
[b] Based on PM10 emission limit of 0.03lb/MMBtu.
[c] Based on NOx emission limit of 0.25lb/MMBtu.
[d] Based on CO emission rate of 0.70 lb/MMBtu.
[e] Based on 10 % of SO_2 emissions.

Table 4. PSD Class II Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	3.96	20
	24-hour	36.7	91
	3-hour	203	512
PM_{10}	Annual	1.67	17
	24-hour	22.2	30
NO_2	Annual	2.24	25

Table 5. PSD Class I Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	0.39	2
	24-hour	3.82	5
	3-hour	22.1	25
PM_{10}	Annual	0.034	4
	24-hour	3.44	8
NO_2	Annual	0.17	2.5

Table 6. Ambient Air Quality Impact

Pollutant	Averaging Time	Modeled Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Total Impact (ug/m^3)	Florida AAQS (ug/m^3)
SO_2	Annual	26	8	34	60
	24-hour	173	21	194	260
	3-hour	440	53	493	1,300
PM_{10}	Annual	12	26	38	50
	24-hour	69	53	123	150
NO_2	Annual	11	26	37	100

Revised Best Available Control Technology (BACT) Determination
U. S. Sugar Corporation
Hendry County
Boiler No. 7
PSD-FL-208

The applicant proposes to install a new bagasse and fuel oil fired boiler at its Clewiston sugar mill. This new boiler, No. 7, will provide steam to the sugar cane processing operations. Two existing bagasse boilers (Nos. 5 and 6) will be retained on standby. In addition, U.S. Sugar Corporation is proposing to raise the stacks of the existing Boilers Nos. 1, 2 and 3 to 150 feet above grade.

The boiler will combust primarily bagasse to generate an average of 350,000 lbs/hr of steam for the mill. The total heat input of Boiler No. 7 at this steam production rate will be 738 MMBtu/hr. Steam production due to fuel oil firing will be approximately 175,000 lbs/hr. Heat input from the No. 2 fuel oil (max. 0.05% sulfur content, by weight) shall not exceed 250 MMBtu/hr. The annual capacity factor (ACF) for No. 2 fuel oil is limited to 10%. Table I lists the pollutants potentially subject to PSD analysis. Table II shows the PSD source applicability. The applicant has proposed the maximum annual tonnage of regulated air pollutants emitted from this boiler based on operation for 8760 hours per year and burning bagasse.

TABLE 1

Boiler No. 7

Pollutant	Potential Emissions (Tons/Yr)		PSD Significant Emission Rate (Tons/Yr)
	Oil	Bagasse	
NO_x	64.40	809	40
SO_2	16.10	550	40
PM	9.7	97	25
PM_{10}	9.7	97	15
CO	21.25	2,262	100
VOC	1.29	685	40
H_2SO_4	1.60	55	7
Be	0.003		0.0004
Hg	0.002		0.1
Pb	0.02		0.6

Rule 62-2.410, Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Table 2. Revised PSD Source Applicability for U.S. Sugar Clewiston Boiler No.7

Regulated Pollutant	Contemporaneous Decreases (TPY) Boiler 5	Boiler 6	Total	Increase Due to Boiler No.7 (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	27.2	33.1	60.3	97[a]	36.7	25	Yes
Particulate(PM10)	24.5	29.8	54.3	97[b]	42.7	15	Yes
Sulfur dioxide	11.1	12.3	23.5	549.5	526.05	40	Yes
Nitrogen oxides	26.4	29.6	56.1	808.1[c]	752.05	40	Yes
Carbon monoxide	1,180.1	1,323.7	2,503.8	2,262.7[d]	-241.1	100	No
Volatile Org.Compds.	44.0	49.4	93.4	685.3	591.85	40	Yes
Lead	-	-	-	0.018	0.018	0.6	No
Mercury	-	-	-	0.0021	0.0021	0.1	No
Beryllium	-	-	-	0.0027	0.0027	0.0004	Yes
Fluorides	-	-	-	0.0041	0.0041	3	No
Sulfuric acid mist [b]	1.1	1.2	2.35	55.0[e]	52.6	7	Yes
Total reduced sulfur	-	-	-	-	-	10	No
Asbestos	-	-	-	-	-	0.007	No
Vinyl Chloride	-	-	-	-	-	0	No

[a] Based on PM emission limit of 0.03 lb/MMBtu.
[b] Based on PM10 emission limit of 0.03lb/MMBtu.
[c] Based on NOx emission limit of 0.25lb/MMBtu.
[d] Based on CO emission rate of 0.70 lb/MMBtu.
[e] Based on 10 % of SO_2 emissions.

Date of Receipt of a BACT Application:

September 17, 1993

Date Application Complete:

July 12, 1994

Waiver of the 90-day Clock:

October 31, 1994

BACT Determination Requested by the Applicant:

Pollutant	Determination
NO_X	Low-NO_X burners/low nitrogen fuel oil Bagasse: 0.25 lb/MMBtu Fuel oil: 0.2 lb/MMBtu
VOC	Good combustion practices
SO_2	Firing very low-sulfur No. 2 fuel oil (maximum of 0.05% sulfur content, by weight), not to exceed 10% of the total potential annual heat input. Bagasse: 0.17 lb SO_2/MMBtu Oil: 0.05 lb SO_2/MMBtu
H_2SO_4 mist	Firing very low-sulfur No. 2 fuel oil (maximum of 0.05% sulfur content, by weight)
PM and PM_{10}	Electrostatic Precipitator Bagasse: 0.03 lb/MMBtu Oil: 0.03 lb/MMBtu
Be	Electrostatic Precipitator

BACT DETERMINATION PROCEDURE

In accordance with Rule 62-212.410, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted above the significant levels which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, 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).

(b) All scientific, engineering, and technical material and other information available to the Department

(c) The emission limiting standards or BACT determination of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically infeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. The air pollutant emissions from this boiler can be grouped into categories based upon what control equipment and techniques are available to control emissions from these types of emission units. Using this approach, the emissions can be classified as follows:

- Combustion Products (PM, PM_{10}, and Heavy Metals). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (CO, VOC, and Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.

- Acid Gases (SO_x, NO_x, HCl, Fl, and H_2SO_4). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT ANALYSIS

Combustion Products (PM), (Be):

Particulate matter (PM) emissions from boilers are related to the combustion air, fuel quality and combustion efficiency. Particulate matter emissions from this project are subject to BACT analysis because the net contemporaneous emission increase is over the PSD significance levels. The applicant has proposed as BACT the installation of an electrostatic precipitator (ESP) to control emissions of particulate matter. This is consistent with the Department determination for several new biomass/fossil fuel fired boilers at existing sugar mill facilities.

Beryllium emissions are also subject to PSD review because they are above the significant levels as given in Rule 62-2.400, Table 212.400-2, F.A.C. In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium from boilers. BACT for these heavy metals is typically represented by the level of particulate control and, in this case, through the use of an electrostatic precipitator. As this is the case, the emission factor of 0.03 lb/MMBtu for PM is judged to represent BACT for beryllium.

Products of Incomplete Combustion (VOC):

The emissions of volatile organic compounds (VOC) are above the significant level and therefore require a BACT analysis. VOC is formed during the incomplete combustion of the fuel. High combustion temperatures, adequate excess air and good fuel/air mixing during combustion will minimize VOC emissions.

The EPA BACT/LAER/RACT Clearinghouse has few BACT determinations for VOC emissions from bagasse combustion in boilers. Historically, BACT emission limits for VOC on bagasse and fuel oil fired boilers have been based on the use of good combustion practices, rather than add-on control system.

In bagasse-fired boilers, the fuel characteristics and the combustion practices result in VOC emissions that are somewhat high, relative to fossil fuel fired boilers. The use of flue gas recirculation (FGR) could theoretically reduce VOC emissions by reburning a portion of the VOCs in the recirculated exhaust. However, the overall effectiveness of FGR is limited and it has never been applied to a bagasse boiler.

Post combustion-VOC controls have not been applied to bagasse fired boilers. Such common techniques as direct-flame incineration, catalyst oxidation, and carbon adsorption techniques were analyzed by the applicant and found not to be technically feasible technologies.

The applicant has proposed good combustion practices and an emission limit of 0.212 lb/MMBtu (bagasse) and 0.004 lb/MMBtu (fuel oil) emissions as BACT for VOC.

<u>Acid Gases</u> (SO_2, H_2SO_4, NO_x):

The emissions of sulfur dioxide, nitrogen oxides, and sulfuric acid mist represent a significant proportion of the total emissions and need to be controlled, if deemed appropriate. Sulfur dioxide emissions from boilers are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of very low-sulfur No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight, to control sulfur dioxide and sulfuric acid mist emissions. Fuel oil use will not exceed 10% of the maximum potential annual heat input.

The applicant has stated that BACT for nitrogen oxides will be met by using low-nitrogen fuel oil (maximum of 0.015% nitrogen content, by weight). When burning bagasse, NO_x emissions shall not exceed 0.25 lb/MMBtu.

Given the applicant's proposed BACT level for nitrogen oxides emissions, as stated above, an evaluation was made of the cost and associated benefit of using each one of the technologies available. The applicant identified the different available control technologies capable of reducing NO_x emissions as: Selective Non Catalytic Reduction (SNCR); Flue Gas Recirculation (FGR); Low-NO_x Burners (LNB); and, low-nitrogen fuel oil. This economic analysis was included in the application (see pages 5-19 through 5-30). The results of this analysis were included in Table 5-6 through Table 5-8.

The incremental cost effectiveness (ICE) values reported are: $6,021/ton SNCR, $10,561/ton using FGR, ($26,725)/ton using LNB and $9,621/ton using low-nitrogen fuel oil. The applicant has proposed the use of low-nitrogen fuel oil (max. 0.015% N content, by wt.) and very low-sulfur fuel oil (max. 0.05% S content, by wt.) as BACT for this emission unit.

<u>BACT Determination by Department:</u>

Based on the information presented by the applicant, the Department believes that the use of low-nitrogen fuel oil (oil firing shall not exceed 10% of the annual capacity factor), an emission limit of 0.25 lb/MMBtu (bagasse firing), and good combustion practices are justifiable as BACT for NO_x control.

For volatile organic compounds emissions, good combustion practices is determined as BACT for the proposed boiler.

For sulfur dioxide and sulfuric acid mist emissions, BACT is represented by firing very low-sulfur No. 2 fuel oil (max. 0.05% S content, by wt.).

For PM and PM_{10} emissions, emission reduction is accomplished by the installation of an electrostatic precipitator as a control device. This method of control has been determined as BACT for a similar facility. The BACT particulate matter standard for Boiler No. 7 shall not exceed 0.03 lb/MMBtu.

For the heavy metal beryllium, BACT is being addressed through the particulate limitation of 0.03 lb/MMBTU, which will be achieved by the installation of an electrostatic precipitator as a control device.

The BACT emission limits for the U.S. Sugar Corporation project are thereby established as follows:

BACT EMISSION LIMITS

Pollutant	lb/MMBtu		lbs/hr	
	Bagasse	Oil	Bagasse	Oil
PM	0.03	0.03	22	7.5
NO_x	0.25	0.20	185	50
SO_2	0.17	0.05	125	12.5
H_2SO_4	0.017	0.005	13	1.25
VOC	0.212	0.004	157	1.0

Details of the Analysis May be Obtained by Contacting:
Mr. Martin Costello, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

1/25, 1995
Date

Approved by:

Virginia B. Wetherell
Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

1-31-95, 1995
Date

Memorandum

Florida Department of
Environmental Protection

TO: Virginia B. Wetherell

FROM: Howard L. Rhodes

DATE: January 25, 1995

SUBJECT: Approval of a PSD Permit (PSD-FL-208)
U. S. Sugar Corporation, Hendry County

Attached for your approval and signature is a PSD permit and a Best Available Control Technology evaluation to construct a 738 MMBtu/hr heat input (350,000 lbs/hr steam) boiler designed to burn bagasse and No. 2 fuel oil at an existing sugar mill in Clewiston, Hendry County, Florida.

The main pollution control technologies are an electrostatic precipitator to minimize particulate emissions; very low sulfur content in the fuel oil to minimize acidic deposition and; low nitrogen in the fuel oil and good combustion practices to minimize ozone precursors.

We received a few comments from EPA which we incorporated into our determination. No comments or objections were received from the public regarding this permit.

I recommend your approval and signature.

HLR/TH/bjb

In the folder labeled as follows there are documents, listed below, which were not reproduced in this electronic file. That folder can be found in one of the file drawers labeled Supplementary Documents Drawer. Folders in that drawer are arranged alphabetically, then by permit number.

Folder Name: U.S. Sugar Corporation

Permit(s) Numbered:

AC	26	-	238006
PSD	FL	-	208

Period during which document was received:		Detailed Description
APPLICATION 27 DEC 1993	1.	24"×36" BLUEPRINT: LOCATION OF CLEWISTON MILL AND OTHER SOURCES RELATIVE TO ENP (DRAWING NUMBER: 41185 - 03)

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

November 14, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Murray T. Brinson
Senior Vice-President, Sugar Processing
United States Sugar Corporation
Post Office Box 1207
Clewiston, Florida 33440-1207

Re: DEP File No.: 0510003-006-AC
Permit No. AC 26-238006 (PSD-FL-208)
Clewiston Facility, Boiler No. 7

Dear Mr. Brinson:

The Department has reviewed your request to utilize alternative Department-approved methods when conducting the initial compliance tests on Boiler No. 7. In particular you wish to use the instrumental Method 7E to determine nitrogen oxides emissions in lieu of the wet chemistry Method 7. You also wish to have the option to use Method 8 that measures sulfuric acid mist and sulfur dioxide emissions simultaneously instead of employing Method 6 which measures only sulfur dioxide. For reference, the instrumental Method 6C is acceptable in lieu of the wet Method 6 for determining sulfur dioxide emissions. The request is acceptable and the above referenced mentioned permit is hereby amended as follows:

SPECIFIC CONDITION No. 20

Sulfur dioxide emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.17 lb/million Btu heat input, as determined by EPA reference Method 6, 6C, or 8 and in accordance with 40 CFR 60, Appendix A. Sulfuric acid mist emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.017 lb/million Btu heat input, as determined by EPA Reference Method 8 and in accordance with 40 CFR 60, Appendix A.

SPECIFIC CONDITION No. 21

Nitrogen oxides emissions, expressed as NO_2, shall not exceed 185 lbs/hr as determined by EPA Reference Method 7 or 7E and in accordance with 40 CFR 60, Appendix A. The fuel oil shall contain no more than 0.015% nitrogen, by weight, as determined using ASTM D4629.

A person whose substantial interests are affected by this permit amendment may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9730, fax: 850/487-4938. Petitions must be filed within fourteen days of receipt of this permit amendment. A petitioner must 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 28-5.207 of the Florida Administrative Code. Mediation is not available for this action.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the action or proposed action.

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 permit amendment. 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.

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 permit amendment.

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 permit amendment 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 and conforms to Rule 62-103.070, F.A.C. Upon timely filing of a petition or a request for an extension of time this permit amendment will not be effective until further order of the Department.

When the Order (Permit Amendment) is final, any party to the Order has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; 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 of appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT AMENDMENT was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11-14-97 to the person(s) listed:

Mr. Murray T. Brinson, U.S. Sugar *
Mr. David A. Buff, P.E.
Mr. David Knowles, SD
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kori Jober 11-14-97
clerk) (Date)

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 J. Brinson
US Sugar Corp.
P O Box 1207
Clewiston, Fl
33440-1207

4a. Article Number
P 265 659 488

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

7. Date of Delivery
11-17-97

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X J. Wheeler

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 488

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 U S Sugar Corp	
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 11-14-97 0510003-006-AC Boiler #7	

PS Form **3800**, April 1995

Memorandum

Florida Department of
Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy

FROM: Al Linero 11/13

DATE: November 13, 1997

SUBJECT: U.S. Sugar Corporation - Clewiston Boiler No. 7
Permit 0510003-006-AC (PSD-FL-208)

Attached is a letter amending the construction permit for bagasse Boiler No. 7 at the subject facility. The applicant wants the option to use Department-approved instrumental methods to measure sulfur dioxide and nitrogen oxides. They also want to use a Department-approved method which simultaneously measures sulfuric acid mist and sulfur dioxide.

The requested methods are at least as accurate and less expensive to conduct than the presently-permitted procedures. The test protocol remains in compliance with all Department and NSPS testing requirements for bagasse boilers and will demonstrate whether the unit will comply with the BACT determination.

I recommend your approval and signature.

Attachments

CHF/aal

Golder Associates Inc.

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

Golder Associates

November 12, 1997

Mr. A. A. Linero, P.E.,
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
NOV 13 1997
BUREAU OF
AIR REGULATION

RE: U.S. Sugar Corporation - Clewiston Boiler No. 7
AC26-238006/PSD-FL-208
Test Protocol

0510003-006-AC

Dear Mr. Linero:

The purpose of this correspondence is to present a test protocol for U.S. Sugar Corporation's Boiler No. 7. As per Specific Condition No. 14 of the Boiler No. 7 construction permit, U.S. Sugar plans to use the following sampling methods and procedures in our upcoming compliance tests:

Particulate Matter (PM)*	EPA Reference Method 5
Sulfur Dioxide (SO_2)	EPA Reference Method 8
Nitrogen Oxides (NO_2)	EPA Reference Method 7E
Sulfuric Acid Mist	EPA Reference Method 8
Visible Emissions (VE)*	EPA Reference Method 9
Carbon Monoxide (CO)	EPA Reference Method 10
Volatile Organic Compounds (VOCs)	EPA Reference Methods 25A and 18

* If circumstances make it infeasible to conduct the PM and visible emissions tests concurrently, we will notify the South District Office.

The compliance test results will be calculated assuming 55% thermal efficiency for the boiler. A thermal efficiency test using the ASME short-form procedure will be conducted to determine actual efficiency within 14 days of the compliance tests. For information purposes only, the PM emission rates employing the results of the ASME short-form procedure will also be calculated and presented.

The above test protocol deviates in some respects from the test methods specified in Permit No. AC26-238006/PSD-FL-208. The differences are as follows:

1. Method 7E for NO_x is requested as an acceptable method in addition to Method 7.

2. Method 8 for SO_2 is requested as an acceptable method in addition to Method 6.

You, Mike Harley and Martin Costello of your staff has been consulted on these changes, and it was agreed that these changes were acceptable. As a result, it is requested that the permit be amended to read as follows:

> 20. Sulfur dioxide emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.17 lb/million Btu heat input, as determined by EPA Reference Method 6 <u>or 8</u> and in accordance with 40 CFR 60, Appendix A. Sulfuric acid mist emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.017 lb/million Btu heat input, as determined by EPA Reference Method 8 and in accordance with 40 CFR 60, Appendix A.
>
> 21. Nitrogen oxides emissions, expressed as NO_2, shall not exceed 185 lbs/hr as determined by EPA Reference Method 7 <u>or 7E</u> and in accordance with 40 CFR 60, Appendix A. The fuel oil shall contain no more than 0.015% nitrogen content, by weight, as determined using ASTM D4629.

Attached is a permit amendment processing fee of $250. If you have any questions, please contact me at (325) 336-5600.

Sincerely,

David A. Buff

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

REGISTERED ENGINEER STATE OF FLORIDA

cc: David Knowles, DEP South District
Don Griffin
Peter Oppenheimer
Steve Neck

9737592-0600

3004

MARY S OR DAVID A BUFF
1527 NW 57TH ST PH 332-6308
GAINESVILLE FL 32605

11/12 19 97

PAY TO THE ORDER OF Florida Dept. of Environ. Protection $ 250.00

Two hundred fifty and no/100 DOLLARS

Florida Credit Union
Gainesville - Ocala - Lake City - Starke (1)

MEMO Proj. 973-7592-0600
U.S. Sugar Boiler No. 7

Mary S Buff

[redacted]

October 31, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Murray T. Brinson
Senior Vice-President, Sugar Processing
United States Sugar Corporation
Post Office Box 1207
Clewiston, Florida 33440-1207

Re: DEP File No.: 0510003-005-AC
Permit No. AC 26-238006 (PSD-FL-208)
Clewiston Facility, Boiler No. 7

Dear Mr. Brinson:

The Department has reviewed your request to extend the current construction permit and to allow additional time to conduct performance tests on Boiler No. 7 at the Clewiston facility. The expiration date of the above mentioned permit is hereby extended from March 31, 1998 to June 1, 1999 and amended as follows:

SPECIFIC CONDITION No. 14. Performance Stack Tests

Within 60 mill operating days after achieving the maximum capacity at which this unit will be operated but no later than 180 mill operating days after initial (I) startup and annually (A) thereafter, the permittee shall conduct performance tests for: sulfur dioxide (I and upon permit renewal), sulfuric acid mist (I), particulate matter (I, A), nitrogen oxides (I, A), volatile organic compounds (I, A), and carbon monoxide (I, A) while burning bagasse. The performance tests shall be conducted in accordance with the provisions of 40 CFR 60.45b and 60.46b. ~~If Boiler No. 7 is unable to conduct the initial performance test due to long term shutdown, the permittee is required to notify the Department within the specified time frames above upon restartup (by telephone: to be followed by confirmation in writing) and also to conduct a performance test as soon as practicable thereafter but not later than 30 days after restartup.~~ Testing of emissions shall be conducted with the emission unit operating at permitted capacity. Permitted capacity is defined at 90-100% of the maximum operating rate allowed by the permit. If it is impracticable to test at permitted capacity, then Boiler 7 may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once Boiler No. 7 is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for the purposes of additional compliance testing to regain the permitted capacity in the permit. Results of the tests shall be submitted to the Department's South Florida District office within 45 days after testing. The Department's South Florida District office shall be notified 30 days prior to any compliance test to allow witnessing.

A person whose substantial interests are affected by this permit amendment may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9730, fax: 850/487-4938. Petitions must be filed within fourteen days of receipt of this permit amendment. A petitioner must 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 28-5.207 of the Florida Administrative Code. Mediation is not available for this action.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the action or proposed action.

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 permit amendment. 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.

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 permit amendment.

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 permit amendment 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 and conforms to Rule 62-103.070, F.A.C. Upon timely filing of a petition or a request for an extension of time this permit amendment will not be effective until further order of the Department.

When the Order (Permit Amendment) is final, any party to the Order has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; 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 of appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT AMENDMENT was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-31-97 to the person(s) listed:

Mr. Murray T. Brinson, U.S. Sugar*
Mr. David A. Buff, P.E.
Mr. David Knowles, SD
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Robert Van Voorhees, Bryan Cave LLP

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Tober (clerk) 10-31-97 (Date)

Fold at line over top of envelope to

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 J. Brunson
U.S. Sugar Corp
P O Box 1207
Clewiston, Fl
33440-1207

4a. Article Number
P 265 659 480

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

7. Date of Delivery
11-3-97

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X [illegible]

PS Form **3811**, December 1994 — Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 480

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

Sent to	Murray Brunson
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	10-31-97

0510003-005 AC
PSO-Fl-208

PS Form **3800**, April 1995

Memorandum

Florida Department of
Environmental Protection

Kim

TO: Howard Rhodes

THROUGH: Al Linero *Al Linero 10/30*

FROM: Teresa Heron *T.H.*

DATE: October 30, 1997

SUBJECT: U.S. Sugar Corporation - Clewiston Boiler No. 7
Permit 0510003-005-AC (PSD-FL-208)

Attached is a letter amending the construction permit for bagasse Boiler No. 7 at the subject facility. The boiler was unable to conduct compliance tests 60 days after reaching full capacity or 180 days after startup. The reason was that the harvest ended before the unit was ready for testing. The change maintains the 60 and 180 days periods as required by the applicable NSPS, but corrects for the seasonal shutdown. Therefore the new basis is mill operating days rather than calendar days. This means that the clock is running as long as cane is harvested whether or not the boiler operates.

We got verbal approval from EPA on this approach. It is also consistent with the references to seasonal operations in the EPA/Florida Performance Partnership.

I recommend your approval and signature.

Attachments

CHF/aal/th

UNITED STATES SUGAR CORPORATION

Post Office Box 1207 • Clewiston, Florida 33440-1207
Telephone 941/983-8121

September 8, 1997

Mr. A. A. Linero, P.E.
Administrator – New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl. 32399-2400

RE: Air Permit AC26-238006/PSD-FL-208
AIRS I.D. No. 0510003-003-AC – USSC Boiler No. 7

0510003-005-AC

Dear Mr. Linero:

We are enclosing processing fee for $250.00 as per request outlined in your September 4, 1997 letter.

Sincerely,

Murray T. Brinson
Senior Vice President, Sugar Processing

MTB:jt
Enclosures

cc: David M. Knowles, P.E., DEP South District
Donald Griffin, USSC
Peter Briggs, USSC
Robert Van Voorhees, Bryan Cave LLP
cc: T. Heron

Vendor: 4450 FLORIDA DEPARTMENT OF Check: 554 Date: 09/09/1997

DESCRIPTION	INVC DATE	GROSS AMOUNT	DISCOUNT AMT	NET AMOUNT
PROCESS FEE-PERMIT-BOILER #7	09/08/97	250.00	0.00	250.00
	TOTALS:	250.00	0.00	250.00

United States Sugar Corporation

United States Sugar Corporation

DETACH ALONG PERFORATION

DETACH ALONG PERFORATION

THIS CHECK IS VOID IF BLUE COLORED BACKGROUND IS ABSENT

United States Sugar Corporation
P.O. Drawer 1207
Clewiston, Florida 33440-1207
(941) 983-8121

First Bank of Clewiston
Clewiston, Florida 33440

Check: 554

Date: 09/09/1997

PAY ONLY $250.00

PAY: Two Hundred Fifty and 0/100ths Dollars

Amount
$250.00

TO THE ORDER OF
FLORIDA DEPARTMENT OF
ENVIROMENTAL PROTECTION
P. O. BOX 3070
TALLAHASSEE FL 32315-3070

VOID IF OVER $250.00

[redacted]

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

September 4, 1997

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Murray T. Brinson
Senior Vice President, Sugar Processing
U. S. Sugar Corporation
Post Office Box 1207
Clewiston, Florida 33440-1207

RE: Request for Revision of Air Permit AC26-238006/PSD-FL-208
AIRS I.D. No. 0510003-003-AC - Clewiston Boiler No. 7

Dear Mr. Roesler:

The Bureau of Air Regulation received your August 21 request for a revision to the above referenced permit. Before we can begin processing your request, we will need a processing fee of $250 pursuant to Rule 62-4.050(4)(r)5, F.A.C. If you have any questions, please call Teresa Heron at (904)488-1344.

Sincerely,

9/4

A. A. Linero, P.E.
Administrator
New Source Review Section
Bureau of Air Regulation

AAL/kt

cc: T. Heron, BAR

no green
Card returned

P 265 659 445

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Murry J. Bunson	
Street & Number US Sugar Corp	
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 9-4-97 0510003-003-AC CB#7	

PS Form **3800**, April 1995

UNITED STATES SUGAR CORPORATION

Post Office Box 1207 • Clewiston, Florida 33440-1207
Telephone 941/983-8121

August 21, 1997

RECEIVED
AUG 26 1997
BUREAU OF
AIR REGULATION

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Fl. 32399-2400

0510003-005-AC

RE: United States Sugar Corporation, Clewiston Boiler No. 7
Air Permit No. AC26-238006/PSD-FL-208, Hendry County
Request for Additional Time to Conduct Initial Performance Testing

Dear Mr. Fancy:

As you discussed earlier this summer with our legal counsel, Bob Van Voorhees, we are requesting an additional 90 days to performance test Clewiston Boiler No. 7. At the same time, we are asking that you extend the expiration date of the boiler's construction permit to June 1, 1999.

The construction permit for this Boiler No. 7 currently requires us to conduct initial performance testing at the earliest of one of three points in times, depending on progress in commissioning and debugging the boiler. These points in time are: (1) within 60 calendar days after achieving maximum capacity, (2) within 180 days after initial startup, or (3) within 30 days after restartup if the boiler cannot be tested prior to seasonal shutdown. 120 days

Boiler No. 7 was started up in January, 1997. We worked on commissioning and debugging the boiler for about three months before the crop ended in late March. Since then, the boiler has been shutdown . We will be able to resume commissioning and debugging the boiler a few days after we begin harvesting this year's sugarcane crop (around late October or early November) and have produced enough bagasse to run the boiler as designed. While we expect to performance test the boiler as soon as possible after restartup, extra time beyond the 30 days allowed in the construction permit may be necessary. To make sure that we have enough time to properly commission the boiler on bagasse, we are asking for 90 additional operating days to conduct the initial performance tests. Of course, we will notify the South District Office upon restartup, and 30 days before the performance testing to allow witnessing.

We are also asking you to extend the expiration date of the boiler's construction permit until June 1, 1999. This will allow enough time for the Department to issue a final Title V operating permit to the Clewiston Mill, ensuring our ability to continue operating Boiler No. 7.

If you have any questions, please contact me or Bob Van Voorhees at (202) 508-6014.

Sincerely,

UNITED STATES SUGAR CORPORATION

Murray T. Brinson

Murray T. Brinson
Senior Vice President, Sugar Processing

MTB:jt

cc: A. A. Linero, DEP
David M. Knowles, P.E., DEP South District
Lisa Gefen, USSC
Peter Briggs, USSC
Donald Griffin, USSC
Robert F. Van Voorhees, Esq., Bryan Cave LLP
David A. Buff, P.E., Golder Associates

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 4, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. David A. Buff, P.E.
Principal Engineer
Golder Associates
6241 Northwest 23rd Street
Suite 500
Gainesville, Florida 32653-1500

Re: U. S. Sugar Corporation
DEP File No. AC26-238006; PSD-FL-208

Dear Mr. Buff:

The Department acknowledges receipt of a copy of your January 31, 1997, letter withdrawing the December 21, 1996, request to amend the referenced permit to reduce Boiler No. 7 potential emissions. Accordingly the Department has ceased processing the December 21 request.

If you have any questions on this matter, please call Willard Hanks at 904/488-1344.

Sincerely,

A A Linero 2/4

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/wh/h

cc: David Knowles, SD
Brian Beals, EPA
John Bunyak, NPS
Don Griffin, U.S. Sugar

[redacted]

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.

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

3. Article Addressed to: David A. Buff, P.E. Golder Assoc. 6241 NW 23rd St Suite 500 Gainesville, Fl 32653-1500	4a. Article Number P 265 659 156
	4b. Service Type ☐ Registered ☑ Certified ☐ Express Mail ☐ Insured ☐ Return Receipt for Merchandise ☐ COD
	7. Date of Delivery 2-6-97
5. Received By: *(Print Name)*	8. Addressee's Address *(Only if requested and fee is paid)*
6. Signature: *(Addressee or Agent)* X Diana Weaver	

PS Form **3811**, December 1994

Domestic Return Receipt

P 265 659 156

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to David Buff	
Street & Number Golder Assoc	
Post Office, State, & ZIP Code Gainesville, 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	2-4-97

PS Form **3800**, April 1995

Golder Associates Inc.

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

Golder Associates

January 31, 1997

Mr. David M. Knowles
District Air Program Administrator
Florida Department of Environmental Protection, South District
2295 Victoria Avenue, Suite 364
Fort Myers, FL 33901-2896

Re: Permit Modification Request, U.S. Sugar Corporation
Clewiston Sugar Mill Expansion
Permit No. 0510003-001-AC
Hendry County - AP
Related to Boiler 7, 0510003-003-AC

Dear Mr. Knowles:

As a result of recent discussions with the Florida Department of Environmental Protection (FDEP) in Tallahassee, the United States Sugar Corporation is withdrawing its construction permit modification request submitted to Tallahassee on December 21, 1996 (copy enclosed). Instead, U.S. Sugar requests a modification to the above-referenced construction permit, reducing allowable operation days to 320 days per year. This reduction will allow U.S. Sugar to accommodate certain engineering design changes described in our letter to you of December 21, 1996, while maintaining the status of the mill expansion as a minor source. These design changes are restated below.

In order to meet anticipated product sales demand, a conditioning silo and a sugar pulverizer will need to be added. Also a fluidized bed V.H.P. sugar dryer/cooler will be added to produce very high pol sugar. The higher quality feed material will allow U.S. Sugar's final product to compete in the dynamic sugar market. In addition, the granular carbon regeneration furnace (GCRF) charging rate will be increased from 40,000 lb/day to 60,000 lb/day of carbon to meet sugar processing needs. The addition of these new sources will increase pollutant emissions above those stated in the original construction permit (0510003-001-AC). However, the requested reduction to 320 operation days and resulting emissions decreases will largely counterbalance emissions increases associated with the new sources.

As noted in the preceding paragraph, U.S. Sugar plans to install a GCRF with a larger charging rate to meet anticipated sugar processing needs. In the absence of emissions offsets from Clewiston Boiler No. 7, projected annual SO_2 emissions from the larger GCRF will approach the PSD significant emissions rate of 40 tons per year (TPY). However, based on its experience in the corn syrup industry, the GCRF manufacturer has guaranteed an SO_2 emissions rate that we believe is too conservative for the cane sugar industry.

U.S. Sugar believes that the amount of sulfur adsorbed by granular carbon in the cane sugar process is significantly lower than for the corn syrup process. To test this hypothesis, U.S. Sugar conducted a series of analytical tests. These tests conclusively demonstrate that little or no sulfur was adsorbed by granular carbon in the cane sugar process. Thus, the granular carbon adsorbate does not contribute to SO_2 emissions in the GCRF gas stream. The only source of SO_2 emissions is from the sulfur content

9651057Y/F1/WP/3

in the No. 2 fuel oil combusted to operate the GCRF. The analytical test procedure and results are enclosed.

Since the maximum emissions from the new baghouse sources are estimated to be much less than 100 TPY, U.S. Sugar requests that the PM compliance test be waived in favor of the alternate 5 percent opacity limit set forth in the Rule 62-297.620(4), F.A.C. The GCRF associated with the expansion is properly defined as an incinerator under Rule 62-210.200 (150), F.A.C. Its revised charging rate will be less than 50 TPD, and therefore the applicable emission limiting standards are contained in Rule 62-296.401(1), F.A.C. Compliance with the standards in this rule will be demonstrated by performing a visible emissions test not to exceed the 5 percent opacity specified in the rule.

In addition to the planned new sources, some of the original mill expansion design specifications have been modified for such items as the baghouses and their associated stacks. Please advise if an additional application fee should be submitted.

Should you have any questions regarding this request, or desire additional information, please contact Paul Wesson of my staff.

Sincerely,

David A. Buff

David A. Buff, P.E.
Florida P.E. #19011
(SEAL)

Enclosures

DB/arz

cc: Clair Fancy, DEP
Pat Comer, DEP
Al Linero, DEP
Don Griffin, U.S. Sugar
Peter Briggs, U.S. Sugar
Lisa Gefen, U.S. Sugar
Peter Oppenheimer, Bryan Cave LLP
Paul Wesson, Golder Associates Inc.
File (2)

9651057Y/F1/WP/3

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): Baghouses (18)	
2. Control Device or Method Code:	

B.

1. Description (limit to 200 characters): Off Gas Afterburner	
2. Control Device or Method Code:	99

C.

1. Description (limit to 200 characters): Venturi wet scrubber	
2. Control Device or Method Code:	53

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): **Process Enclosed**
2. Control Device or Method Code: **54**

B.

1. Description (limit to 200 characters): **Impingement Plate scrubber**
2. Control Device or Method Code: **55**

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer:	Model Number:
4. Generator Nameplate Rating:	MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F 0.5 seconds 1,600 °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:		mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:	704,000	TPY sugar
5. Operating Capacity Comment (limit to 200 characters): Max production rate refers to bulk and bagged sugar.		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:	
24 hours/day	7 days/week
52 weeks/yr	7,680 hours/yr

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Attachment UC-EU1-E1	
2. Emission Point Type Code: [ ] 1 [ ] 2 [x] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): See Attachment A	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W	
6. Stack Height:	142 feet
7. Exit Diameter:	5 feet
8. Exit Temperature:	120 °F

9. Actual Volumetric Flow Rate:	105,223	acfm
10. Percent Water Vapor:	5	%
11. Maximum Dry Standard Flow Rate:	91,000	dscfm
12. Nonstack Emission Point Height:		feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):		
14. Emission Point Comment (limit to 200 characters): **Stack parameters represent white sugar dryer baghouse stack. See Attachment A, Table 3-6 for list of all stacks and their parameters in this emissions unit.**		

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):

   Food and Agriculture - Sugar cane processing, general

2. Source Classification Code (SCC):

   3-02-015-01

3. SCC Units:

   Tons Sugar Produced

4. Maximum Hourly Rate:	5. Maximum Annual Rate:
100	**704,000**

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur:	8. Maximum Percent Ash:

9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

    Max hourly & annual rates refer to the amount of sugar produced by the white sugar fluidized bed drying system and loaded via the bulk shipment facility.

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Food and Agriculture - Sugar Cane Processing, general**	
2. Source Classification Code (SCC): **3-02-015-01**	
3. SCC Units: **Tons Sugar Produced**	
4. Maximum Hourly Rate: **120**	5. Maximum Annual Rate: **600,000**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment (limit to 200 characters): **Max hourly and max annual rates refer to the amount of sugar produced by the Very High Pol (V.H.P.) sugar fluidized bed drying system.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Food and Agriculture - Sugar Cane Processing, Other Not Classified.**	
2. Source Classification Code (SCC): **3-02-015-99**	
3. SCC Units: **Tons Processed**	
4. Maximum Hourly Rate: **85**	5. Maximum Annual Rate: **640,000**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment (limit to 200 characters): **Maximum hourly and maximum annual rates based on 2,000 TPD, and refer to the amount of sugar that could be processed through the packaging operations.**	

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **In-Process Fuel Use; Distillate Oil; General**	
2. Source Classification Code (SCC): **3-90-005-89**	
3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **0.12**	5. Maximum Annual Rate: **922**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.03**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **135**	
10. Segment Comment (limit to 200 characters): **Max annual rate: 921.6 (rounded to 922). Max rates refer to the amount of No. 2 fuel oil burned in the granular carbon regeneration furnace and the afterburner.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 4.83 lb/hour 14.86 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: Reference: See Att. A
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): See Attachment A
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): See Attachment A for complete calculations and description of control equipment.

Emissions Unit Information Section 1 of 1

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: 14.86 TPY		
4. Equivalent Allowable Emissions:	4.83 lb/hour	14.86 tons/year
5. Method of Compliance (limit to 60 characters): Annual VE test using EPA Method 9.		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Operation is subject to the process weight table, but US Sugar requests that potential worst-case emissions be based on calculations shown in Attachment A.		

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: PM10
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 4.83 lb/hour 14.86 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: Reference: See Att. A
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): See Attachment A
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): See Attachment A for complete calculations and descriptions of control equipment.

Emissions Unit Information Section 1 of 1

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: 14.86 TPY		
4. Equivalent Allowable Emissions:	4.83 lb/hour	14.86 tons/year
5. Method of Compliance (limit to 60 characters): Annual VE Test using EPA Method 9		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Operation is subject to the process weight table, but US Sugar requests that potential worst-case emissions be based on calculations shown in Attachment A.		

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:	lb/hour	18.4 tons/year
4. Synthetically Limited? [x] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr		
6. Emission Factor: Reference: See Attachment A		
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): See Attachment A		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page)

A.

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):

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: SO2	
2. Total Percent Efficiency of Control: %	
3. Potential Emissions: 0.492 lb/hour	1.89 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr	
6. Emission Factor: Reference: See Attachment A	
7. Emissions Method Code: [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5	
8. Calculation of Emissions (limit to 600 characters): See Attachment A	
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): See carbon regeneration furnace data for emissions analysis. SO2 emissions are from fuel oil combustion only.	

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page)

A.

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):

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: NOX	
2. Total Percent Efficiency of Control: %	
3. Potential Emissions: 3.22 lb/hour	12.3 tons/year
4. Synthetically Limited? [ ] Yes [x] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr	
6. Emission Factor: Reference: See Attachment A	
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5	
8. Calculation of Emissions (limit to 600 characters): See Attachment A	
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):	

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page)

A.

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):

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: CO

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 3.03 lb/hour 11.6 tons/year

4. Synthetically Limited? [ ] Yes [x] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor:

   Reference: See Attachment A

7. Emissions Method Code:

   [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Attachment A

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page)

A.

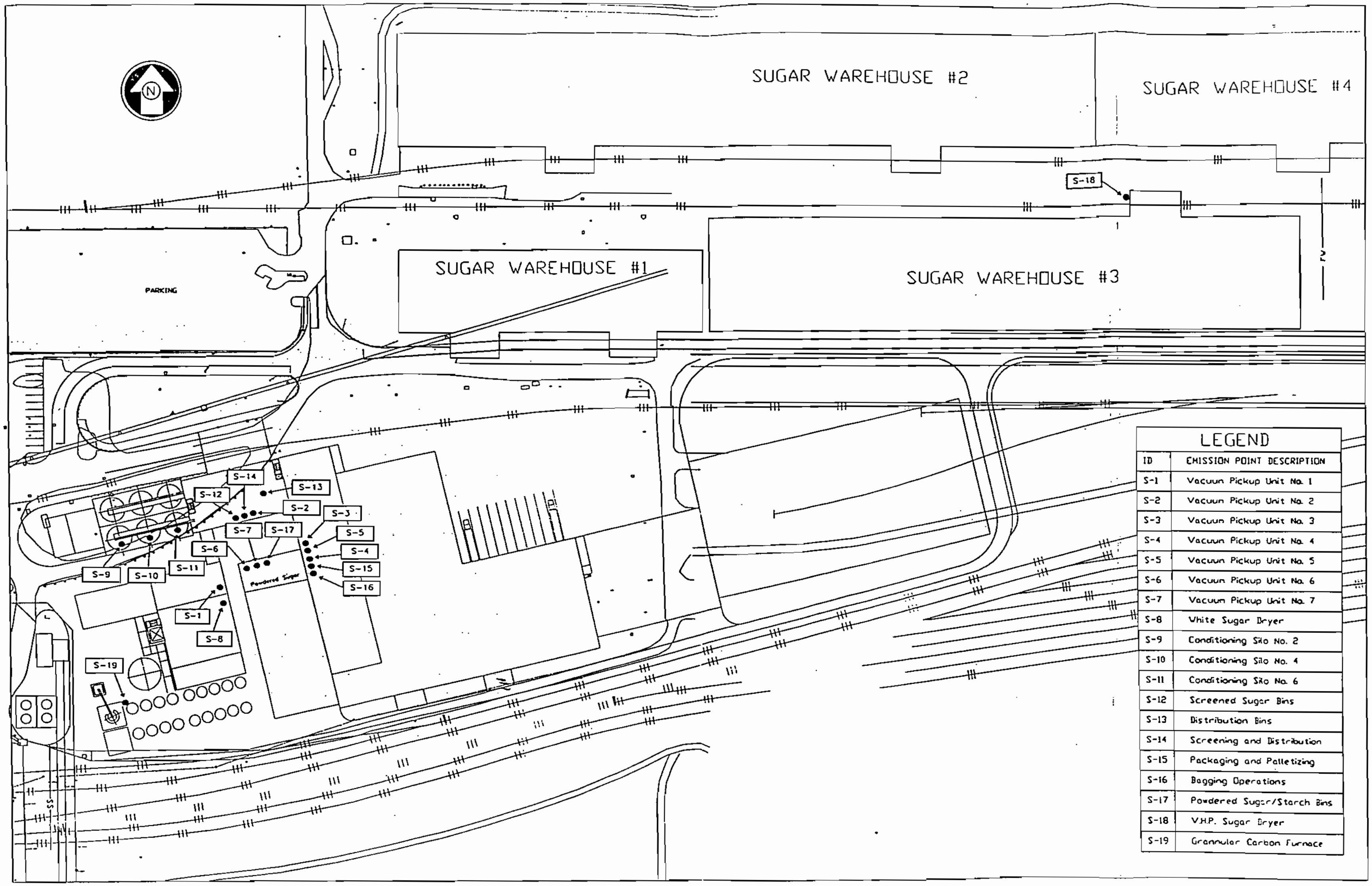
1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

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):

ATTACHMENT UC-FE-2

FACILITY PLOT PLAN



LEGEND

ID	EMISSION POINT DESCRIPTION
S-1	Vacuum Pickup Unit No. 1
S-2	Vacuum Pickup Unit No. 2
S-3	Vacuum Pickup Unit No. 3
S-4	Vacuum Pickup Unit No. 4
S-5	Vacuum Pickup Unit No. 5
S-6	Vacuum Pickup Unit No. 6
S-7	Vacuum Pickup Unit No. 7
S-8	White Sugar Dryer
S-9	Conditioning Silo No. 2
S-10	Conditioning Silo No. 4
S-11	Conditioning Silo No. 6
S-12	Screened Sugar Bins
S-13	Distribution Bins
S-14	Screening and Distribution
S-15	Packaging and Palletizing
S-16	Bagging Operations
S-17	Powdered Sugar/Starch Bins
S-18	V.H.P. Sugar Dryer
S-19	Granular Carbon Furnace

Attachment UC-FE-2B
Mill Expansion Plot Plan

Source: United States Sugar Corporation

KBN
A GOLDER ASSOCIATES COMPANY

Table 3-1. Summary of PM/PM10 Emissions from the Baghouses Associated With the Mill Expansion, U.S. Sugar Corporation

Source / Vent Name	Stack Number	Control Type	Manufacturer/Model ^a	Design Capacity	Control Efficiency (percent)	Operating Hours	PM/PM10 Emissions (gr/dscf)	(lb/hr)	(TPY)
Vacuum Pickup Unit No. 1	S-1	Baghouse	Hoffman	3,000 dscfm	99.9	3,600	0.0025	0.064	0.116
Vacuum Pickup Unit No. 2	S-2	Baghouse	Hoffman	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Vacuum Pickup Unit No. 3	S-3	Baghouse	Hoffman	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Vacuum Pickup Unit No. 4	S-4	Baghouse	Hoffman	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Vacuum Pickup Unit No. 5	S-5	Baghouse	Hoffman	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Vacuum Pickup Unit No. 6	S-6	Baghouse	Hoffman	3,000 dscfm	99.9	3,600	0.0025	0.064	0.116
Vacuum Pickup Unit No. 7	S-7	Baghouse	Hoffman	3,000 dscfm	99.9	3,600	0.0025	0.064	0.116
White Sugar Dryer	S-8	Baghouse	Mikropul	91,000 dscfm	99.9	7,680	0.00184 ^b	1.436 ^c	5.51
Conditioning Silo No. 2	S-9	Baghouse	Torit & Day 100PJD8	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Conditioning Silos No. 4	S-10	Baghouse	Torit & Day 100PJD8	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Conditioning Silos No. 6	S-11	Baghouse	Torit & Day 100PJD8	3,000 dscfm	99.9	7,680	0.0025	0.064	0.247
Screened Sugar Bins	S-12	Baghouse	Torit & Day 100PJD8	100 dscfm	99.9	7,680	0.0025	0.0021	0.0082
Distribution Bins	S-13	Baghouse	Torit & Day 100PJD8	100 dscfm	99.9	7,680	0.0025	0.0021	0.0082
Screening and Distribution	S-14	Baghouse	Torit & Day 100PJD8	3,200 dscfm	99.9	7,680	0.0025	0.069	0.263
Packaging and Palletizing Area	S-15	Baghouse	Torit & Day 36PJD8	1,000 dscfm	99.9	7,680	0.0025	0.021	0.082
Bagging Operations	S-16	Baghouse	Torit & Day 100PJD8	11,900 dscfm	99.9	7,680	0.0025	0.255	0.979
Powdered Sugar / Starch Bins	S-17	Baghouse	Torit & Day 100PJD8 & 9PJD8	5,940 dscfm	99.9	7,680	0.0025	0.127	0.489
V.H.P. Sugar Dryer	S-18	Baghouse	Mikropul	103,000 dscfm	99.9	3,600	0.00184 ^b	1.625 ^c	2.925
							Total =	4.18	12.34

Footnotes:
^a Manufacturer and model are supplied for informational purposes only. Final design specifications will be similar but, manufacturer may differ.
^b. Back calculated from guaranteed emission rate and design flow rate.
^c. Manufacturer's guaranteed emission rate. See dryer baghouses manufacturer emission data.

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 3-2. 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	2.5
NOx	3.0	3.0	11.5
SO2	0.49 (d)	0.49	1.89
CO	3.0	3.0	11.5
VOC	1.0	1.0	3.8

Notes: (a) Estimated emissions obtained from design information provided by BSP Thermal Sytems, Inc.

(b) Based on 7,680 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. See carbon regeneration furnace data for calculations. Scrubber SO2 removal is not considered.

Table 3-3. 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 3-4. Estimated Emissions due to Propane Combustion, USSC Mill Expansion.

Parameter	Propane
OPERATING DATA	
Maximum Operating Hours (hr/yr)	7,000
Heat Input Rate (MMBtu/hr)	1.5
Propane (gal/hr) [a]	15.9
Propane (gal/yr)	111,111
Propane (scf/hr) [a]	588.2
Propane (scf/yr)	4,117,647

Pollutant	Emission Factor [b]	Propane	
		lb/hr	TPY
EMISSIONS DATA			
SO_2: Propane	0.018 lb/Mgal [c]	0.00029	0.0010
NOx: Propane	14 lb/Mgal	0.22	0.78
PM/PM10: Propane	0.4 lb/Mgal	0.0063	0.022
CO: Propane	1.9 lb/Mgal	0.030	0.11
NMVOC: Propane	0.5 lb/Mgal	0.0079	0.028

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 3-6. Stack and Vent Geometry and Operating Data for U.S. Sugar Clewiston Mill Expansion.

Source	Stack Number	Stack/Vent Release Height (ft)	Stack/Vent Diameter (ft)	Air Flow Rate acfm	Air Flow Rate scfm	Air Flow Rate dscfm	Gas Exit Temperature (°F)	Water Vapor Content (%)	Velocity (ft/sec)
Vacuum Pickup Unit No. 1	S-1	105	1.0	3,280	3,093	3,000	100	3	69.6
Vacuum Pickup Unit No. 2	S-2	142	1.0	3,280	3,093	3,000	100	3	69.6
Vacuum Pickup Unit No. 3	S-3	142	1.0	3,280	3,093	3,000	100	3	69.6
Vacuum Pickup Unit No. 4	S-4	45	1.0	3,280	3,093	3,000	100	3	69.6
Vacuum Pickup Unit No. 5	S-5	45	1.0	3,280	3,093	3,000	100	3	69.6
Vacuum Pickup Unit No. 6	S-6	45	1.0	3,280	3,093	3,000	100	3	69.6
Vacuum Pickup Unit No. 7	S-7	45	1.0	3,280	3,093	3,000	100	3	69.6
White Sugar Dryer Baghouse	S-8	142	5.0	105,223	95,789	91,000	120	5	89.3
Conditioning Silo No.2	S-9	142	1.0	3,280	3,093	3,000	100	3	69.6
Conditioning Silo No.4	S-10	142	1.0	3,280	3,093	3,000	100	3	69.6
Conditioning Silo No.6	S-11	142	1.0	3,280	3,093	3,000	100	3	69.6
Screened Sugar Bins	S-12	142	0.5	109	103	100	100	3	9.3
Distribution Bins	S-13	142	0.5	109	103	100	100	3	9.3
Screening and Distribution Area	S-14	142	1.0	3,499	3,299	3,200	100	3	74.2
Packaging and Palletizing Area	S-15	45	1.0	1,093	1,031	1,000	100	3	23.2
Bagging Operations	S-16	45	2.0	13,012	12,268	11,900	100	3	69.0
Powdered Sugar / Starch Bins	S-17	45	2.0	6,495	6,124	5,940	100	3	34.5
V.H.P. Sugar Dryer Baghouse	S-18	55	5.0	119,099	108,421	103,000	120	5	101.1
Granular Carbon Regeneration Furnace Stack	S-19	30	2.0	4,300	3,662	2,746	160	25	22.8

Note: acfm = actual cubic feet per minute
dscfm = dry standard cubic feet per minute
scfm = standard cubic feet per minute

ATTACHMENT UC-EU1-E1

EMISSION POINT INFORMATION

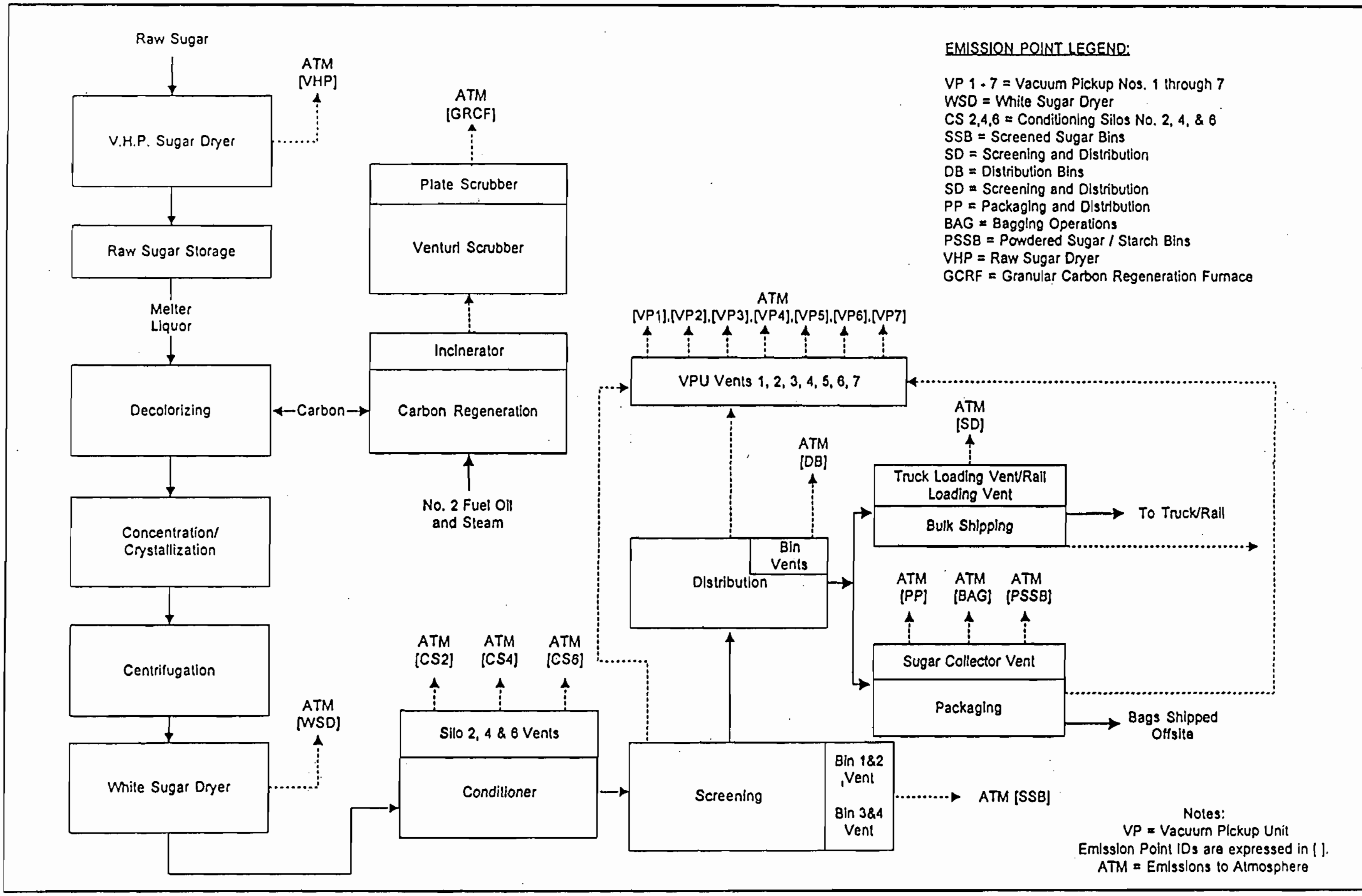
ATTACHMENT UC-EU1-E1
EMISSION POINT INFORMATION

Descriptions of Emissions Points Comprising the Emission Unit:

VP1 = Vacuum Pickup No. 1
VP2 = Vacuum Pickup No. 2
VP3 = Vacuum Pickup No. 3
VP4 = Vacuum Pickup No. 4
VP5 = Vacuum Pickup No. 5
VP6 = Vacuum Pickup No. 6
VP7 = Vacuum Pickup No. 7
WSD = White Sugar Dryer
CS2 = Conditioning Silo No. 2
CS4 = Conditioning Silo No. 4
CS6 = Conditioning Silo No. 6
SSB = Screened Sugar Bins
DB = Distribution Bins
SD = Screening and Distribution
PP = Packaging and Palletizing
BAG = Bagging Operations
PSSB = Powdered Sugar / Starch Bins
VHP = V.H.P. Sugar Dryer
GCRF = Granular Carbon Regeneration Furnace

ATTACHMENT UC-EU1-L1

PROCESS FLOW DIAGRAM



Attachment UC-EU1-L1 Mill Expansion Process Flow Diagram U.S. Sugar Corporation Clewiston, FL	Process Flow Legend Solid/Liquid ————→ Air ············→	Mill Expansion Flow Diagram Filename: UCEU1L1.VSD Date: 12/20/96	KBN A Golder Associates Company

Table 3-5 PSD Source Applicability Analysis for U.S. Sugar Corporation, Clewiston Mill Expansion

Regulated Pollutant	Potential Emissions from Mill Expansion (TPY)					Net Increase in Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Applies?
	Baghouses	GCRF(a)	Alcohol Usage	Propane Heater	Total			
PM(TSP)	12.34	2.50	--	0.022	14.86	14.86	25	No
PM10 (b)	12.34	2.50	--	0.022	14.86	14.86	15	No
Sulfur Dioxide	--	1.89	--	0.001	1.89	1.89	40	No
Nitrogen Dioxide	--	11.5	--	0.78	12.3	12.3	40	No
Carbon Monoxide	--	11.5	--	0.11	11.6	11.6	100	No
VOC	--	3.8	14.61	0.028	18.4	18.4	40	No

Footnote:
(a) GCRF = Granular Carbon Regeneration Furnace
(b) PM10 emission estimates reflect the assumption that all PM is PM10.

ATTACHMENT UC-EU1-L2

FUEL ANALYSIS

ATTACHMENT UC-EU1-L2
Fuel Analysis Specification for U.S. Sugar Corporation
Granular Carbon Regeneration Furnace

Fuel Parameter	Very Low Sulfur No. 2 Fuel Oil (a) (0.03% max S)
Density (lb/gal)	6.83
Approximate Heating Value (Btu/lb)	19,766
Approximate Heating Value (Btu/gal)	135,000
Ultimate Analysis (dry basis):	
Carbon	87.3%
Hydrogen	12.6%
Nitrogen	0.006%
Oxygen	0.04%
Sulfur	0.03%
Ash/Inorganic	< 0.01%
Moisture	--

Note: All values represent average fuel characteristics.

Footnotes:
(a) Source: Perry's Chemical Engineers' Handbook. Sixth Edition.

ATTACHMENT UC-EU1-L3

CONTROL EQUIPMENT PARAMETERS

Control Equipment Parameters for the Off Gas Afterburner on the Granular Carbon Furnace at Clewiston Mill Expansion

Manufacturer	BSP Thermal Systems, Inc.	
Model No.	BSP Zero Hearth Type Afterburner for 10'-9" OD x 8 HTH Furnace	
Outlet Gas Temp (°F) Min/Max	1,200 / 1,400	
Outlet Gas Flow Rate (ACFM) Min/Max	10,600 / 16,300	(a)
Gas residentce time (sec) Min/Max	0.5 / 0.75	
Incinerator Temp (°F) Min/Max	800 / 1,600	
Total VOC Destruction Efficiency (%)	92.0	

(a) Flow Rate at 1400°F

Control Equipment Parameters for Granular Carbon Regeneration Furnace Wet Collection System at Clewiston Mill Expansion

Manufacturer and Model No.	Sly Manufacturing Company High Energy Venturi Wet Scrubber With Tray Type Wet Scrubber
Outlet Gas Temp (°F)	160
Outlet Gas Flow Rate (ACFM)	4,300
Pressure Drop Across Venturi Scrubber (inches of H2O) Min/Max	20 / 30
Pressure Drop Across Tray Scrubber (inches of H2O) Min/Max	3 / 5
Venturi Scrubbant Flow Rate (gal/min) - Min	36
Tray Scrubbant Flow Rate (gal/min) - Min	230
Venturi Scrubbant Supply Pressure (psi) - Min	3
Tray Scrubbant Supply Pressure (psi) - Min	Free Flow
Average Scrubbant pH - Min/Max	6 / 9
Scrubbant Make-up Rate (gal/min)	4.5
Wet Scrubbing System Particulate Removal Efficiency	97%

Note: All values are based on manufacturers design information and are subject to revision.
All values represent typical operating conditions.

Control Equipment Parameters for the Vacuum Pickup Baghouses
Clewiston Mill Expansion

Vacuum Pickup Points No.1 ,2, 3 , 4, 5, 6, and 7 Baghouses Exhausts Vent to Stack Numbers S-1, S-2, S-3, S-4, S-5, S-6, S-7, respectively	
Manufacturer and Model No.	Hoffman (or similar)
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	3,280
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	3,000
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media of each Baghouse (sq. ft)	1,000
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.064

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the White Sugar Dryer Baghouse
Clewiston Mill Expansion

White Sugar Dryer Baghouse Exhaust Vents to Stack Number S-8	
Manufacturer	Micropul (or similar)
Outlet Gas Temp (°F)	120
Outlet Gas Flow Rate (ACFM)	105,223
Exhaust Gas Moisture Content (%)	5
Outlet Gas Flow Rate (DSCFM)	91,000
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media (sq. ft)	30,333
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0018
Pollutants	Outlet Loading lb/hr
Particulate Matter	1.436

Note: Parameters are average values based on manufacturers design specifications.
Outlet loading rate is guaranteed by baghouse manufacturer.

Control Equipment Parameters for the Conditioning Silo Baghouses
Clewiston Mill Expansion

Conditioning Silos No. 2, No.4 and No. 6 Baghouses Exhausts Vent to Stack Numbers S-9, S-10, S-11, respectively	
Manufacturer and Model No.	Torit & Day (or similar) 100PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	3,280
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	3,000
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media of each Baghouse (sq. ft)	1,000
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.064

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the Screened Sugar Bins Baghouse
Clewiston Mill Expansion

Screened Sugar Bins Baghouse Exhaust Vents to Stack Number S-12	
Manufacturer and Model No.	Torit & Day (or similar) 100PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	109
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	100
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media (sq. ft)	33
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.0021

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the Distribution Bins Baghouse
Clewiston Mill Expansion

Distribution Bins Baghouse Exhaust Vents to Stack Number S-13	
Manufacturer and Model No.	Torit & Day (or similar) 100PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	109
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	100
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media (sq. ft)	33
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.0021

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the Screening and Distribution Baghouse
Clewiston Mill Expansion

Screening and Distribution Baghouse Exhaust Vents to Stack Number S-14	
Manufacturer and Model No.	Torit & Day (or similar) 100PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	3,499
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	3,200
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media (sq. ft)	1,067
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.069

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the Packaging and Palletizing Area Baghouse
Clewiston Mill Expansion

Packaging and Palletizing Area Baghouse Exhaust Vents to Stack Number S-15	
Manufacturer and Model No.	Torit & Day (or similar) 36PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	1,093
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	1,000
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media (sq. ft)	333
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.021

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the Bagging Operations Baghouses
Clewiston Mill Expansion

Bagging Operations Baghouses Exhaust Vents to Stack Number S-16	
Manufacturer and Model No.	Torit & Day (or similar) 100PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	13,012
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	11,900
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media of all Baghouses (sq. ft)	3,967
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.255

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

Control Equipment Parameters for the Powdered Sugar / Starch Bin Baghouses
Clewiston Mill Expansion

Powdered Sugar / Starch Bins Baghouses Exhaust Vents to Stack Number S-17	
Manufacturer and Model No.	Torit & Day (or similar) 100PJD8 and 9PJD8
Outlet Gas Temp (°F)	100
Outlet Gas Flow Rate (ACFM)	6,495
Exhaust Gas Moisture Content (%)	3
Outlet Gas Flow Rate (DSCFM)	5,940
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media of all Baghouses (sq. ft)	1,980
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0025
Pollutants	Outlet Loading lb/hr
Particulate Matter	0.127

Note: Parameters are average values based on manufacturers design specifications.

Sample calculations:

Outlet loading rate (lb/hr) = outlet gas flow rate (dscfm) X outlet loading rate (grains/dscf) ÷ 7000 grains/lb X 60 min/hr

**Control Equipment Parameters for the Raw Sugar Dryer Baghouse
Clewiston Mill Expansion**

Raw Sugar Dryer Baghouse Exhaust Vents to Stack Number S-18	
Manufacturer	Micropul (or similar)
Outlet Gas Temp (°F)	120
Outlet Gas Flow Rate (ACFM)	119,099
Exhaust Gas Moisture Content (%)	5
Outlet Gas Flow Rate (DSCFM)	103,000
Cleaning Method	Air Pulse Jet cleaning (Timer Actuated)
Bag Material	Gore-Tex Polyester or Similar
Total Area of Filter Media (sq. ft)	34,333
Air to Cloth Ratio (CFM/sq. ft)	3.0
Manufacturer's Guaranteed Outlet Loading (grains/DSCF)	0.0018
Pollutants	Outlet Loading lb/hr
Particulate Matter	1.625

Note: Parameters are average values based on manufacturers design specifications.
Outlet loading rate is guaranteed by baghouse manufacturer.

CARBON REGENERATION FURNACE DATA

GRANULAR CARBON REGENERATION FURNACE (GCRF) SO_2 STACK EMISSIONS ESTIMATES

Granular carbon is used in the sugar refining process to remove colorants and organic compounds from the cane sugar solution passed through the carbon columns. At the Clewiston facility, after the granular carbon becomes saturated with colorants and organics, the carbon will be regenerated. Regeneration occurs in a large furnace called the granular carbon regeneration furnace (GCRF). The carbon is then reused in the filtration process.

SO_2 emissions from the GCRF originate from combustion of the fuel oil necessary to operate the unit. If sulfur compounds in the cane sugar solution exist in organic form or are bonded to an organic such as a protein, the sulfur will be adsorbed onto the carbon. SO_2 emissions may also result during regeneration from the release of the sulfur that has been adsorbed on the carbon from filtration of the cane liquor. The manufacturer's estimated SO_2 emissions (attached) for the GCRF are considered to be conservative since they are based on its experience in the corn syrup industry. To the best of our knowledge, there is no SO_2 emissions data available for similar GCRF's installed at other refined sugar processing facilities.

U.S. Sugar believes that the amount of sulfur adsorbed by granular carbon in the cane sugar process is significantly lower than for the corn syrup process. To test this hypothesis, U.S. Sugar conducted a series of analytical tests. Observation of the results on the next page shows that for either analytical method performed (HPIC or ICP), effluent concentrations can exceed influent concentrations. This is physically impossible on a mass balance basis. Clearly, the variance in influent and effluent concentrations of the cane liquor can be attributed to standard analytical test error. According to the laboratory, all the results are within the testing equipment analytical error for the specific tests performed.

In theory, at the cane liquor filtration point in the sugar refining process, there should be little or no sulfur either in the form of organic sulfur compounds or sulfur bonded to organic compounds dissolved in solution. As a result, there should be little or no sulfur adsorbed onto the carbon and eventually released in the regeneration process. However, this is not true for corn syrup processing because organic sulfur compounds do exist in the corn liquor stream.

These tests demonstrate that no sulfur was adsorbed by granular carbon in the cane sugar process. Thus, the granular carbon adsorbate does not contribute to SO_2 emissions in the GCRF gas stream during regeneration and the only source of SO_2 emissions is from fuel oil combustion. Calculation of the SO_2 from fuel oil combustion (0.03% sulfur content) is shown below.

120 gal/hr X 0.03% X 6.83 lb sulfur/gal oil X 2 lb SO_2/1 lb sulfur = 0.49176 lb/hr

0.49176 lb SO_2/hr X 7,680 hr/yr X 1 Ton/2000 lb = 1.89 TPY SO_2

UNITED STATES SUGAR CORPORATION
Inter-Office Correspondence
CLEWISTON, FLORIDA

January 24, 1996

TO: Mr. Donald Griffin

FROM: R. P. DeStefano

SUBJECT:

Sulfur Analyses-Granular Carbon Feed and Effluent

We have analyzed the eight samples of syrup delivered to the research Department by Mr. Alex Posada on January 21 and 23. We have used two completely independent methods of analysis, namely high performance ion chromatography (HPIC) and inductively coupled plasma (ICP)spectroscopy. The former method relies on the fact that essentially all of the sulfur in cane sugars has been found to be in the sulfate form. The sulfate content is measured by ion chromatography and then converted to equivalent sulfur. The ICP method, on the other hand determines sulfur directly. Based upon the results of these analyses (Table 1), it appears that sulfur passes through the carbon bed with no measurable absorption or loss.

Table 1. Sulfur (mg/l) in feed and effluent streams of granular carbon adsorber.

	Sulfur (mg/l)	
Sample Identification	HPIC	ICP
1/19/97 1:30PM Start Feed	168	147
1/19/97 7:30PM Effluent	157	151
1/21/97 7:30AM Feed	172	158
1/21/97 7:30AM Effluent	173	145
1/22/97 1:30AM Feed	157	149
1/22/97 7:30AM Effluent	163	144
1/22/97 7:30PM Feed	166	158
1/23/97 1:30AM Effluent	165	144

MEMORANDUM

To: Don Griffin
From: Alex Posada
Subject: Granular Carbon Columns Sulfur Tests
Date: 1/23/97

TEST DESCRIPTION

A homogeneous sample of raw sugar was collected and dissolved into a 65 brix solution. The solution was screened down to 50 microns using a 100 mesh testing sieve and a 50 micron water filtration element. It was then heated to 55 °C in a hot water bath and fed into two glass carbon columns, in series, using a peristaltic pump. The solution was heated to 85 °C by passing it through a hot water bath before entering the columns. The columns were kept at 85 °C by a hot water circulator. Column effluent samples were collected and analyzed for sulfur content.

OPERATION PARAMETERS

Flow into Columns

Volumetric : 1.7 ml/min
Mass : 0.19 lb/hr

Retention Time

6 hrs

Effluent Sampling Frequency

Every 6 hrs

Columns

Width : 1.0 in
Length : 24 in
Volume: 308 ml

12-18-1996 3:57PM FROM **BEST AVAILABLE COPY**
DEC-18-1996 10:05 BSP THERMAL SYSTEMS INC. +1 415 591 1383 P.01

BSP THERMAL SYSTEMS INC.™

BSP THERMAL SYSTEMS, INC.
Continuing The Business of BSP Technology
1121 Industrial Road, Suite D
San Carlos, CA 94070

TEL: (415) 591-6762 / (800) 222-5575
FAX: (415) 591-1383

FAX MESSAGE

DATE: 12/18/96 TIME: 9:47 AM PST

TO: STONE & WEBSTER

FROM: ROB KEELER

ATTN: MR. CHUCK VACHER

CC: *DON GRIFFIN-USSC (BY MAIL)*
AL FOMIN
MAYNARD ISHEIM

FAX #: (770) 481-4120

CC: Joe Buuk
Purchasing

NO. OF PAGES (Including this Page): 3

SUBJECT: ANTICIPATED EMISSIONS FOR 60,000 LBS./DAY
REGENERATED CARBON CAPACITY FURNACE
INVITATION FOR BID #06604-M-731-103096
BSP PROPOSAL #E-1056

IN RESPONSE TO YOUR TELEPHONE REQUEST, THE FOLLOWING IS A TABLE OF ANTICIPATED STACK EMISSIONS FOR THE SUBJECT CAPACITY SIZE MULTIPLE HEARTH FURNACE:

TYPE STACK EMISSIONS	LBS./HR.
PM10	
97% EFF.	0.98
98% EFF.	0.65
NOx	2.76
SO2	
PLAIN RECIRC. WATER SCRUBBING	10.56 •
WITH NaOH WATER TREATMENT	5.46 •
CO	2.64
VOC	1.02

NOTED DEC 18 1996 O. K. Fuchs

• SO2: THESE ARE HIGH FIGURES AND ARE ESTIMATED BEYOND JUST CONSIDERING 0.03% SULFUR CONTENT IN FUEL OIL. A MORE ACCURATE ESTIMATE CAN BE MADE BASED ON YOUR PROCESS SULFUR MATERIAL BALANCE EVALUATION. ALSO, SO2 IS MORE SOLUBLE IN COLDER WATER SO THE LOWER THE SCRUBBER EXIT TEMPERATURE THE LOWER EMISSIONS (WE USE 160 DEG. F).

ENCLOSED IS A COPY OF "STACK EMISSIONS", PG. 12 & 13 FROM OUR PROPOSAL FOR YOUR REVIEW. FURTHER, WE RECOMMEND THAT YOU REVIEW OUR FAX's TO ED LAVERGNE OF 4/18/96 AND 4/22/96.

IF YOU REQUIRE ANY FURTHER INFORMATION, PLEASE DO NOT HESITATE TO CONTACT THE WRITER OR OUR AL FOMIN, CHIEF ENGINEER.

RJK

BEST AVAILABLE COPY

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

FAX MESSAGE

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

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

CC: A. FOMIN
M. ISHEIM

ATTN: [redacted]

FAX #: 1-770-481-4110

NO. OF PAGES (including this page): 2

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

MESSAGE:
ED:

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

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

OUTLET GAS TEMP.	1200 DEG. F - 1400 DEG. F	
OUTLET GAS FLOW RATE	10,600 MIN. 16,300 MAX. ACFM AT 1400 DEG. F.	
GAS RESIDENCE TIME	0.5 SEC. MIN., 0.75 SEC. MAX.	
MHF TEMPERATURE	HTH 1	800 DEG. F.
	HTH 8	1600 DEG. F.
EST. VOC EFF.	ESTIMATE = 92%	

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

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

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

WATER FLOW RATES

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

OTHER POLLUTANTS GIVEN IN PREVIOUS CORRESPONDENCE.

AS ALWAYS PLEASE TREAT THIS INFORMATION AS CONFIDENTIAL.

REGARDS,

ROB KEELER

V.H.P. SUGAR AND WHITE SUGAR DRYER BAGHOUSES
MANUFACTURER GUARANTEED EMISSION DATA

BMA

Master
M Damms
R Johnson
R Duffy

Raw Sugar Dryer

An/to:
United States Sugar Corporation
Attn. Mr. Michael Damms
Assistant to Senior Vice President -
USSC Sugar Houses
Clewiston

Telefax: 001-941-983-4255

Seiten / pages: 1

Von/from:
Dr. Lothar Krell

Telefon: (0531) 804-580
Telefax: (0531) 804-203

Zeichen / ref.:
TT/kr-sp

Datum / date: 11/21/96

VHP-Sugar Dryer/Cooler

Dear Mr. Damms,

As requested in your fax dated 11/20/96 we wish to provide you with the numbers of total particulate dust loading from the dust collector.

The guarantees read as follows:

Maximum emission load:	1.625 lbs/hr
Estimated average emission load:	0.772 lbs/hr

These numbers are related to the process air flow rate 103,000 SCFM.

Feel free to contact us, if you have any further questions.

With best regards,

Braunschweigische Maschinenbauanstalt AG
TAG-Division

i. V. Dr. Krell

NOV 1996
CLEWISTON
SUGAR HOUSE

dokument6

BMA®

White Sugar Dryer

Emission Guarantee:

Max. total dust emission from unit: 1.436 lbs/h.

based on:

Process air flow rate = 91,000 scfm

Maximum particle dust load from D/C
before bag house = 14.0 gr/cft

Sugar grain size distribution:

MA = 450 ±40 micron

CV = 41.6 ±6%.

59371so2.doc

BMA, SUGAR-Division
Braunschweigische
Maschinenbauanstalt AG

Am Alten Bahnhof 5
D-38122 Braunschweig
Postfach 32 25
D-38022 Braunschweig

Germany
Telefon 05 31-804-0
Telefax 05 31-804-216
Telex/Teletex 17531107 12

Sitz der Gesellschaft
Braunschweig
Handelsregister HRB 69

Vorsitzender des Aufsichtsrats
Dr. Jürgen Deilmann
Vorstand Rolf W. Könnecke, Vors.
Dipl.-Ing. Siegfried Matusch

KBN
A GOLDER ASSOCIATES COMPANY

December 21, 1996

Mr. David Knowles
District Air Program, Administrator, South District
Florida Department of Environmental Protection
2295 Victoria Avenue, Suite 364
Fort Myers, FL 33901-2896

Re: U.S. Sugar Corporation
Clewiston Sugar Mill Expansion
Permit No.0510003-001-AC
Hendry County -AP

Dear Mr. Knowles:

United States Sugar Corporation (U.S. Sugar) recently obtained the above referenced non-PSD air construction permit to expand the existing Clewiston sugar mill. Since the construction permit was issued, U.S. Sugar's final design engineering of the expansion has resulted in certain changes to the plant, which in turn will result in emissions changes.

In order to meet anticipated product sales demand, a conditioning silo and a sugar pulverizer will need to be added. Also a fluidized bed V.H.P. sugar dryer/cooler will be added to produce very high pole sugar. The higher quality feed material will allow U.S. Sugar's final product to compete in the dynamic sugar market. In addition, the granular carbon regeneration furnace (GCRF) charging rate will be increased from 40,000 lb/day to 60,000 lb/day of carbon to meet sugar processing needs. The addition of these new sources will increase pollutant emissions above those stated in the original construction permit.

The current construction permit for the mill expansion was issued based on maximum PM/PM10 emissions of 14.0 TPY. The estimated increase in emissions aggregated with PM/PM10 emissions from currently permitted emissions units is 18.0 TPY and exceeds the 15 tons per year (TPY) PM10 PSD significant emission rate by 3.0 TPY (4.0 TPY PM over that stated in the original construction permit application). U.S. Sugar plans to offset this increase in PM/PM10 emissions by reducing the hours of operation of the newly constructed Boiler No. 7, permit no. AC26-238006; PSD-FL-208, to achieve a 4.0 TPY PM reduction for the project. A copy of the letter to Mr. Linero requesting this revision is attached.

Since the maximum emissions from the new baghouse sources are estimated to much less than 100 TPY, U.S. Sugar requests that the PM compliance test be waived in favor of the alternate 5 percent opacity limit set forth in the Rule 62-297.620(4), F.A.C. The GCRF associated with the expansion is properly defined as an incinerator under Rule 62-210.200 (150), F.A.C. Its new charging rate will be less than 50 TPD, and therefore the applicable emission limiting standards are contained in Rule 62-296.401(1), F.A.C. Compliance with the standards in this rule will be demonstrated by performing a visible emissions test not to exceed the 5 percent opacity specified in the rule.

In addition to the new sources described above, some of the original mill expansion design specifications have been modified for such items as the baghouses and their associated stacks. The attachments provided should

9651057Y/F1/WP/2

replace their counterpart pages in the original permit application dated August 12, 1996. Changes to the project description and a number of the specific conditions of permit no. 0510003-001-AC will also be necessary. Enclosed is the permit modification application fee of $250.

If you have any comments or questions concerning this request, or desire additional information, please contact me directly.

Sincerely,

David A. Buff

David A. Buff, P.E.
Principal, KBN
Florida P.E. #19011
(SEAL)

DB/arz
Enclosures

cc: Don Griffin, U.S. Sugar Corporation
Peter Oppenheimer, Bryan Cave LLP
Paul Wesson, KBN
File (2)

MEMORANDUM

TO: Clair Fancy, BAR
Pat Comer, OGC

FROM: Bob Van Voorhees

Date: January 21, 1997

Re: Emissions Offsets Available from Clewiston Boiler No. 7

I. INTRODUCTION

To obtain PM-10 emissions offsets for its mill expansion, the United States Sugar Corporation (U.S. Sugar) recently requested that the Department of Environmental Protection (DEP) amend Clewiston Boiler No. 7's air construction permit to reduce its annual hours of operation. The reduction in Boiler No. 7's hours of operations would accommodate an increase in PM-10 emissions associated with changes made in the final design engineering of the mill expansion, while maintaining the status of the mill expansion as a minor source. A detailed explanation of the projected PM-10 emission increases resulting from design engineering changes at the mill expansion and offsetting PM-10 emissions decreases requested from Clewiston Boiler No. 7 was presented in a letter dated December 21, 1996 from David Buff to A. A. Linero (copy attached).

U.S. Sugar obtained a PSD air construction permit for Clewiston Boiler No. 7 on February 2, 1995. Construction commenced soon thereafter and was completed in December, 1996. The boiler was officially started up in early January, 1997,[1/] and is in the process of being commissioned. Compliance testing is scheduled to occur either before the end of the 1996-97 crop season, or at the beginning of the 1997-98 crop season. Clewiston Boiler No. 7 is currently permitted to operate 8,760 hours per year.

The analysis presented below demonstrates that the proposed PM-10 emissions decreases from Clewiston Boiler No. 7 should be and are creditable as offsets for the proposed mill expansion.

II. EXECUTIVE SUMMARY

Under federal and Florida air regulations, a modification to an existing major source that results in a significant net increase in emissions is subject to PSD preconstruction

1/ "Startup" is a regulatory term indicating that an emissions unit has begun operating. See Rule 62-210.200(272), F.A.C., and 40 CFR § 52.01(e) (1995).

review and permitting.[2/] An increase of PM-10 emissions is significant if it exceeds 15 tons per year (TPY).

Under both the Florida and federal PSD regulations, an increase in potential emissions from a proposed unit can be offset by a decrease in actual emissions from another unit at the same source if the decrease in actual emissions is contemporaneous, federally-enforceable, and otherwise creditable. A decrease in emissions is creditable from a unit that has been constructed, even if that unit has not yet begun normal operation.[3/] For such a unit, actual emissions equal potential (or allowable) emissions.[4/] Therefore, a federally-enforceable permit condition reducing the unit's potential emissions creates a creditable emissions decrease that can be used to offset an emissions increase from a proposed unit at the same source.

Plainly, emissions decreases from Clewiston Boiler No. 7 would be creditable, since the unit has been constructed, started-up, and is currently operating. Additionally, since the boiler is in the commissioning phase and has not yet begun normal operation, its actual emissions are equal to its potential emissions. The PM-10 emissions decreases from Clewiston Boiler No. 7 requested by U.S. Sugar sufficiently offset the proposed PM-10 emissions increases from the mill expansion, subjecting the proposed expansion to DEP's minor new source preconstruction rules rather than its PSD preconstruction rules.

III. DISCUSSION

Under the Florida air rules, a modification (*i.e.*, the mill expansion) at an existing major facility (*i.e.*, the Clewiston Mill) triggers the requirements of the state's PSD regulations only if the modification would result in a significant net emissions increase.[5/] Florida's PSD rules define "modification" as:

> "... any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any air

---

2/ Florida has delegated authority to administer the federal PSD program. See 40 CFR § 52.520(c)(78)(i)(A) and 40 CFR § 52.530. The federal PSD rules were promulgated at 45 Fed. Reg. 52676 (Aug. 7, 1980).

3/ Based on an apparent misunderstanding of Clewiston Boiler No. 7's operating status, staff at EPA Region IV were reportedly uncomfortable with an emissions decrease being granted from this unit. Reference was made to page A.38 of EPA's draft New Source Review Workshop Manual (Oct. 1990), which states that an emissions decrease can not be credited from a unit that has never been constructed or operated. This statement is plainly inapplicable to Clewiston Boiler No. 7, since the unit has been constructed and is now operating. More to the point is page A.29 of that reference, which states that the "new" emissions levels for a new or modified emissions unit which has not begun normal operation is its potential to emit.

4/ DEP rules define both "allowable emissions" [Rule 62-210.200(24), F.A.C.] and potential emissions" [Rule 62-210.200(225), F.A.C.]. The major distinction is that the definition of "allowable emissions" takes into account state enforceable restrictions when calculating maximum emissions, while the definition of "potential emissions" does not. In this instance, the terms are functionally synonymous since the relevant terms and conditions of Clewiston Boiler No. 7's construction permit are both state and federally enforceable.

5/ See Rule 62-212.400(2)(b)4., F.A.C. See also 40 CFR § 52.21(b)(2).

pollutant subject to regulation under the [Clean Air] Act, including any not previously emitted, from any emissions unit or facility."[6/]

A net emissions increase occurs as the result of a "modification" when:

"... the sum of all of the contemporaneous creditable increases and decreases in the actual emissions of the facility, including the increase in emissions of the modification itself and any increases and decreases in quantifiable fugitive emissions, is greater than zero."[7/]

A net emissions increase is "significant" if it is equal to or greater than the applicable emissions rate listed in Table 212.400-2 (Regulated Air Pollutants - Significant Emission Rates).[8/] For PM-10, the significant emissions rate is 15 TPY.[9/]

For an emissions unit (other than an electric utility steam generating unit) which has not yet begun normal operation on a particular date, DEP rules state that "actual emissions shall equal the potential emissions of the emissions unit on that date."[10/]

Thus, to determine if a significant net emissions increase that would trigger the Department's PSD rules has occurred, changes in actual emissions at the source must be summed. If PM-10 emissions increases associated with the proposed modification (*i.e.*, the mill expansion) minus creditable PM-10 emissions decreases from existing units at the source (*i.e.*, from reduced operating hours at Clewiston Boiler No. 7) are less than 15 TPY, then the net emissions increase is not significant and PSD review is not triggered.

6/ Rule 62-210.200(185), F.A.C. See also 40 CFR § 52.01(d).

7/ Rule 62-212.400(2)(e)1., F.A.C. See also 40 CFR § 52.21(b)(3)(i).

8/ Rule 62-212.400(2)(e)2., F.A.C. See also 40 CFR § 52.21(b)(23)(i).

9/ Table 212.400-2, F.A.C. See also 40 CFR § 52.21(b)(23)(i).

10/ Rule 62-210.200(12)(c), F.A.C. "Actual emissions" are defined by the Florida rules as:
"The actual rate of emissions of a pollutant from an emissions unit as determined in accordance with the following provisions:

(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.
(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.
(c) For any emissions unit (other than an electric utility steam generating unit specified in subparagraph (d) of this definition) which has not begun normal operation on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date."

(Emphasis supplied.) See also 40 CFR § 52.21(b)(iv), which contains a virtually identical definition.

Boiler No. 7 is not an electric utility steam generating unit as defined by Rule 62-210.200(106), F.A.C.,[11] a fact reflected in Specific Condition No. 11 of its permit, AC 26-238006/PSD-FL-208.

Subparagraph (c) of Florida's definition of "actual emissions, " Rule 62-210.200(12), F.A.C., makes clear that emissions offsets may be obtained from a unit which has been constructed, even though the unit has not yet begun normal operation. This point is reinforced by EPA's draft New Source Review Workshop Manual (Oct. 1990), which states that "An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that received a PSD permit."[12] The implicit corollary of this statement is that emissions decreases from a source which has been constructed and is operating are creditable. For such a unit, actual emissions are equal to potential emissions. Boiler No. 7 has not yet begun normal operation because it is still in the process of being commissioned in preparation for compliance testing. Therefore, actual emissions for Boiler No. 7 "shall equal the potential to emit of the unit on that date."[13] Boiler No. 7's potential emissions are equal to emissions allowed by its federally-enforceable PSD construction permit, and further restrictions on potential emissions as requested by U.S. Sugar would be both contemporaneous and creditable as emissions decreases.

Accordingly, the emissions offsets from Clewiston Boiler No. 7 should be credited, resulting in no significant net emissions increase in PM-10 emissions from the proposed mill expansion.

33092.03

11/ "Electric utility steam generating unit" is defined by DEP as "any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the unit." See also 40 CFR § 51.165(xx).

12/ EPA New Source Review Workshop Manual (Draft, Oct., 1990), at p. A.38.

13/ Rule 62-210.200(12)(c), F.A.C.

Golder Associates Inc.

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

Golder Associates

January 16, 1997

RECEIVED
JAN 21 1997
BUREAU OF
AIR REGULATION

Mr. Clair Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

Re: U. S. Sugar Corporation
Clewiston Boiler No. 7
DEP File No. AC26-238006; PSD-FL-208

Dear Mr. Fancy:

As you are aware, United States Sugar Corporation (U.S. Sugar) recently requested that emissions offsets from the new Boiler No. 7 at the Clewiston mill be approved to allow the construction of a mill expansion without triggering PSD review. Boiler No. 7 has been constructed and the boiler started operations this month. It has been requested that Boiler No. 7 operating hours be decreased from 8,760 hr/yr (365 days/yr) to 8,400 hr/yr (350 days/yr) to provide an emissions offset of 3.0 TPY of particulate matter (PM).

It is our understanding that EPA Region 4 has raised some concerns about this request, citing page A.38 of the draft document entitled "New Source Review Workshop Manual" (October 1990) (copy of this page attached). This reference, under Section III.B.3, discusses creditable contemporaneous emissions changes allowed under PSD rules. The pertinent sentence from this section reads as follows:

> An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that received a PSD permit.

This statement was meant to apply to a situation where a source received a permit, but never built the emissions unit(s) for which the permit was granted. The source then requested the use of these"paper" emissions as offset credit. This clearly does not apply in the current case since Boiler No. 7 has in fact been constructed, and is now operating. I find no regulatory basis for extending this restriction to cases where a source has been built and is operating.

In the present case, Boiler No. 7 has been constructed and is now operating. To date, U.S. Sugar has spent approximately $10 million in designing, permitting, installing and starting up Boiler No. 7. This boiler is the first of its kind in the industry, with an ESP for PM control. There is nothing "paper" about the boiler or the emissions offsets to be obtained by decreasing its annual hours of

9651057A/04

operation. But due to the newness of the boiler, there is currently no test data and little operating history.

To the best of my knowledge there is no state rule which would prohibit offsets from Boiler No. 7 to be granted. I do not believe the draft guidance cited by EPA is relevant, or that it can be used as the basis for denying this request.

EPA has also raised a concern that Boiler No. 7 is "over-permitted", i.e., that it was permitted with no intention of operating 8,760 hr/yr. This concern is unfounded and not supported by the facts. The following facts demonstrate that the boiler was in fact designed and built with the intention of operating 8,760 hr/yr:

- During the crop season, Boiler No. 7 will provide steam for several purposes. The crop season generally runs from late October to mid-March. Steam needs during this time including the following:

  1. Provide steam to the sugar mill, replacing steam previously provided by Boiler Nos. 5 and 6, which have been placed on standby status as a specific condition of Boiler No. 7's construction permit.

  2. Provide steam to the new mill expansion (sugar processing system).

  3. Generate electricity for use in the sugar mill and in the new mill expansion.

  4. Generate electricity for sale to the grid and/or use by a nearby citrus processing plant (Southern Gardens Citrus Processing Corporation). The electric needs of the citrus processing facility are high due to the large refrigeration systems required to store citrus products.

- During the off-season, Boiler No. 7 will provide steam for several purposes. The off-season is the from approximately mid-March to late October, when the sugar mill is not operating. Steam needs during this period include the following:

  1. Provide steam to the new mill expansion (sugar processing system). The new mill expansion is scheduled to operate up to 325 to 350 days per year, depending on market demand and other factors. Thus, it will operate year-around. The permit application for the mill expansion requests 8,760 hr/yr operation.

2. Generate electricity for use in the sugar mill (to power lights, electrical equipment, etc.), and for the new mill expansion.

3. Generate electricity for sale to the grid and/or use by the nearby citrus processing plant. The electric needs of this facility are high throughout the year due to the large refrigeration systems required to store citrus products.

As described above, Boiler No. 7 was designed and built to operate year around to support the sugar mill, the new mill expansion, and the citrus processing plant. The fuel supply for Boiler No. 7 will come from bagasse during the crop season, and during the off-season, from excess bagasse generated from both the Clewiston and Bryant mills. Excess bagasse from both mills is now sold to Great Lakes Chemical for furfural production. This excess bagasse will be stockpiled and used in Boiler No. 7 as needed. As needed, Boiler No. 7 can also burn No. 2 fuel oil as a supplemental fuel. The large capital investment in Boiler No. 7 also dictates that it be utilized to the greatest extent practical.

As demonstrated by the above discussion, this boiler is not "over-permitted". U.S. Sugar would prefer to maintain the ability to operate the boiler 8,760 hr/yr. However, in order to permit the new mill expansion, U.S. Sugar is giving up some of this ability. This will require the company to purchase electricity during days on which the boiler cannot operate due to the restriction on operating hours. This will have an economic impact on U.S. Sugar.

In addition, it is very clear in the Florida PSD rules that offset credit can be taken from Boiler No. 7 in this case. The key lies in the definition of "actual emissions". Rule 62-210.200(12)(c), F.A.C., states that:

> For any emissions unit...which has not begun normal operations on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date.

Since Boiler No. 7 has not yet begun normal operations, the actual emissions of Boiler No. 7 equals the boiler's potential emissions. Therefore, the decrease in allowable (potential) emissions from Boiler No. 7 which we are requesting also represents the decrease in Boiler No. 7 actual emissions. This rule was adopted specifically to address the situation presented here: normal operation of the source has yet to begin, and there is little operating history.

In addition, Rule 62-210.200(12)(b), F.A.C., states the following:

> The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.

These PSD rules and definitions were adopted by Florida and approved by EPA. The rules provide the requirements for determining creditable emissions offsets for sources which have not begun normal operations. Based on these rules, the reduction in potential emissions from Boiler No. 7 should be allowed for offset credit. The guidance which EPA refers to is not applicable to this situation, since this boiler has been built and is operating.

Based on the above considerations, I request that the Department approve U.S. Sugar's request for offset credit for Boiler No. 7. I appreciate your consideration of these comments. Please contact me directly if you have any questions concerning this request, or desire additional information.

Sincerely,

David A. Buff

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

DAVID A. BUFF CERTIFICATE NO. 19011 STATE OF FLORIDA REGISTERED ENGINEER SEAL

DB/vjp

cc: Murray Brinson
Don Griffin
Lisa Gefen
Peter Oppenheimer
David Knowles
Willard Hanks
File (2)

cc: a. linero

9651057A/04

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 10, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. David A. Buff, P.E.
KBN Engineering & Applied Sciences
6241 Northwest 23rd Street
Suite 500
Gainesville, FL 32653-1500

Re: U. S. Sugar Corporation, Clewiston Boiler No. 7
AC 26-238006, PSD-FL-208

Dear Mr. Buff:

The Department has reviewed the November 22, 1996, proposed Operation and Maintenance (O&M) plan to control carbon monoxide and volatile organic compound emissions from the referenced boiler. EPA's Compliance Assurance Monitoring (CAM) regulation should be reviewed before finalizing the O&M plan. It may help avoid duplicate and unnecessary monitoring.

The Department is approving your November, 1996 O&M plan for boiler No. 7 with the additional condition that U. S. Sugar implement the CAM plan that applies to good combustion practices for this boiler no later than the following crop season after it is promulgated. Should the CAM plan not impose monitoring of the flue gases, the Department will require either an oxygen, carbon dioxide, or carbon monoxide gas monitoring instrument be installed on the boiler and used to confirm good combustion practice of the boiler.

If you have any questions on this matter, please contact Willard Hanks at 904/488-1344.

Sincerely,

AA Linero 1/10

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/wh/h

cc: Mr. David Knowles, SD
Mr. Don Griffin, U. S. Sugar

Fold at line over top of envelope to
the right of the return address

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:
David A. Buff, P.E.
Golder Assoc
6241 NW 23rd St.
Gainesville, Fl
32653-1500

4a. Article Number
P 265 659 146

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

7. Date of Delivery
1/13/97

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X Karen Allen

PS Form **3811,** December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 146

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

Sent to David Buff	
Street & Number Golder Assoc	
Post Office, State, & ZIP Code Gainesville, 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 1-10-97 PSD-Fl-208 / CB No. 7	

PS Form **3800**, April 1995

A GOLDER ASSOCIATES COMPANY

0510003-003-AC

December 21, 1996

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

RECEIVED
DEC 24 1996
BUREAU OF
AIR REGULATION

RE: U.S. Sugar Corporation
Clewiston Boiler No. 7
DEP File No. AC26-238006; PSD-FL-208
Hendry County -AP

Dear Mr. Linero:

United States Sugar Corporation (U.S. Sugar) recently obtained a non-PSD air construction permit from the South District Office to expand their existing Clewiston sugar mill. This construction permit (0510003-001-AC), issued by the South district office on October 25, 1996, was based on permit was issued based on the associated construction permit application which presented maximum PM/PM10 emissions as 14.0 TPY.

Since the original construction permit was issued, U.S. Sugar's final design engineering of the plant has resulted in some changes to the plant. This has resulted in some changes in emissions along with some additional sources. Total maximum PM/PM10 emissions now are 18.0 TPY from the new mill expansion.

In order to accommodate this increase in PM/PM10 emissions from the new mill expansion, and maintain non-PSD applicability, U.S. Sugar desires to obtain emissions offsets from the new Boiler No. 7, which has not yet started operations. Startup of Boiler No. 7 is planned for January, 1997.

According to the Florida PSD rules (Rule 62-212.400, F.A.C.), modifications to major facilities do not require PSD review if the modification would not result in a significant net emissions increase [Rule 62-212.400(2)(d)4., F.A.C.]. For PM, the significant emission rate is 25 TPY; for PM10 it is 15 TPY. The net emissions increase is determined by summing the increase in emissions from the modification itself (i.e., the new mill expansion), and any contemporaneous creditable increases or decreases in the actual emissions of the facility.

The requested total PM10 emissions from the mill expansion are now 18.0 TPY. Standing alone, this increase in emissions exceeds the PSD significant emission rate for PM10 of 15 TPY. To avoid PSD review, a contemporaneous net decreases in emissions of 3.0 TPY or more is required. The contemporaneous emission offsets will be obtained from Boiler No. 7 by reducing the boiler's permitted operating days.

Since Boiler No. 7 has not yet begun normal operations, the actual emissions of Boiler No. 7 equals the boiler's potential emissions [Rule 62-210.200(12)(b), F.A.C.]. Therefore, the decrease in actual emissions from Boiler No. 7 is equal to the decrease in its potential emissions. To provide the offset, Boiler No. 7

16101A/13

6241 Northwest 23rd Street, Suite 500, Gainesville, Florida 32653-1500, 352-336-5600 FAX 352-336-6603
5405 West Cypress Street, Suite 215, Tampa, Florida 33607, 813-287-1717 FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910 FAX 407-994-9393
7785 Baymeadows Way, Suite 105, Jacksonville, Florida 32256, 904-739-5600 FAX 904-739-7777
1616 'P' Street NW, Suite 350, Washington, DC 20036, 202-462-1100 FAX 202-462-2270

operating hours will be limited to 8,400 hr/yr (equivalent to 350 days per year at 24 hrs/day). The offset in PM10 emissions is calculated as follows:

Current permitted PM10 emissions = 97.0 TPY

Proposed revised permitted PM10 emissions =
22.14 lb/hr x 8,400 hr/yr ÷ 2,000 lb/ton = 93.0 TPY

Emissions offset = 97.0 TPY - 93.0 TPY = 4.0 TPY

Net increase in PM10 emissions due to project:

Sugar Processing Facility	18.0 TPY
Boiler No. 7 offsets	-4.0 TPY
Net increase	14.0 TPY

The net increase in emissions for PM10 will be less than 15 TPY, and therefore PSD review does not apply to the revised mill expansion. It is also noted that the net increase in new PM/PM10 emissions is equal to the increase in emissions presented in the original application for the sugar processing facility (14.0 TPY).

The planned changes to the plant, and the associated increase in emissions, is being requested through the South District office. Mr. David Knowles of the South District has been advised of our plans, and is in agreement with our approach to use emission offsets from Boiler No. 7. Revisions to the construction permit for the mill expansion are being submitted concurrently with this request to your office concerning Boiler No. 7.

The table below presents the revised allowable emissions for Boiler No. 7 based on the decrease in allowable operating hours to 8,400 hr/yr:

ALLOWABLE EMISSIONS

	Bagasse			No.2 Fuel Oil		
Pollutant	lb/MMBtu	lbs/hr	tons/yr	lb/MMBtu	lb/hr	tons/yr
Particulate Matter (PM)	0.03	22	93	0.03	7.5	9.7
PM_{10}	0.03	22	93	0.03	7.5	9.7
Sulfur Dioxide	0.17	125	527	0.05	12.5	16.10
Nitrogen Oxides	0.25	185	775	0.2	50.0	64.40
Carbon Monoxide	0.70	516	2,170	0.066	16.5	21.25
Volatile Organic Compounds	0.212	157	657	0.004	1.0	1.29
Sulfuric Acid Mist	0.017	13	53	0.005	1.25	1.60

These changes should be incorporated into a construction permit modification for Boiler No. 7. Specific Condition 1 of the construction permit should be revised to incorporate these revised allowable emissions, as well as the decreased maximum operating hours.

The creditable emission offsets due to this reduction in maximum operating hours is documented below, based on the allowable emissions in the original permit, and the revised allowables shown above:

PM/PM10: 97 TPY - 93 TPY = 4.0 TPY

Sulfur dioxide: 550 TPY - 527 TPY = 23 TPY

Nitrogen oxides: 809 TPY - 775 TPY = 34 TPY

Carbon monoxide: 2,262 TPY - 2,170 TPY = 92 TPY

Volatile organic compounds: 685 TPY - 657 TPY = 28 TPY

Enclosed is permit modification fee of $250. It is believed that this change to Boiler No. 7 would not require a public notice, since allowable emissions are being decreased.

If you have any comments or questions concerning this request, or desire additional information, please contact me directly.

Sincerely,

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

DB/arz

cc: Murray Brinson
Don Griffin
Lisa Gefen
Peter Oppenheimer
David Knowles
File (2)

cc: W. Hanks, BAR
EPA
NPS

C

021845

KBN ENGINEERING AND APPLIED SCIENCES, INC.

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	12/23/96	Permit Application Fee		$250.00

KBN Engineering and Applied Sciences, Inc.

GENERAL DISBURSEMENT ACCOUNT

PH. 352-336-5600

6241 N.W. 23RD ST., SUITE 500

GAINESVILLE, FL 32653-1500

First Union National Bank of Florida

Gainesville, Florida 32605

021845

December 23 1996

PAY ********250**********DOLLARS AND 00 CENTS $ **250.00

TO THE ORDER OF Florida Dept. of Environmental Protection

KBN ENGINEERING AND APPLIED SCIENCES, INC.

Bernard F. Kirby

AUTHORIZED SIGNATURE

[redacted]

BEST AVAILABLE COPY

KBN
A GOLDER ASSOCIATES COMPANY

Date ?

November 22, 1996

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: US Sugar Corporation
Clewiston Boiler No. 7
DEP File No. AC26-238006; PSD-FL-208
Boiler Operation and Maintenance Plan

Dear Mr. Linero:

The purpose of this letter is to submit for approval an Operation & Maintenance (O&M) plan to minimize CO and VOC emissions from United States Sugar Corporation's Clewiston Boiler No. 7. The O&M plan is required by Specific Condition 22 of the above referenced air construction permit. US Sugar will implement the O&M plan for VOC and CO emissions upon approval by the Department. If you have any comments or questions concerning this proposed O&M plan, or desire additional information, please contact me directly.

Sincerely,

David A. Buff

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

cc: W. Hanks, BAR

DB/arz

cc: Murray Brinson
Don Griffin
Lisa Gefen
Peter Oppenheimer
David Knowles

16101A/11

UNITED STATES SUGAR CORPORATION
CLEWISTON MILL BOILER NO. 7

OPERATION AND MAINTENANCE GUIDELINES FOR CO AND VOC EMISSIONS

PURPOSE OF O&M PLAN

An air construction permit was issued by the Florida Department of Environmental Protection (FDEP) for Clewiston Boiler No. 7 on January 31, 1995 (AC26-238006; PSD-FL-208). Specific Condition No. 22 of this permit requires that carbon monoxide (CO) and volatile organic compound (VOC) emissions from Boiler No. 7 be maintained at the lowest possible level through implementation of an Operation and Maintenance (O&M) plan that has been approved by the Department. The O&M plan presents operating procedures and guidelines for the minimization of CO and VOC emissions, consistent with good combustion practices and the pollution control equipment installed on the boiler.

PREPARATION FOR OPERATION

1. The boiler, air ductwork, and air heaters will be properly cleaned, inspected and repaired during routine boiler maintenance.

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 proper 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. The settings of the combustion controls and linkages to fuel feeders, forced draft fan, and overfire air fan will be checked during routine boiler maintenance.

9. All instruments for boiler operation and control will be inspected, repaired and calibrated as required during routine boiler maintenance. These activities will be 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 operations so as to minimize emissions of CO and VOC. This instructional program 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 of CO and VOC.

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, the following procedures will be implemented:

Startup Procedures

1. During startup of the boiler, the fuel feed and combustion air are gradually increased. Care is taken not to overload the fuel bed, until a clean, brisk fire is obtained over the entire grate area. If excessive smoking is observed during the start-up period, the amount of fuel being fed to the grates is reduced until the condition is corrected.

2. After a good burning fuel bed is established over the entire grate, the fuel bed is checked for proper distribution by observing through the observation sight glasses in the side walls.

3. During the start-up period, all of the stoker control components are normally operated on manual, and the maximum stoker operation is limited to about 40% of rated capacity.

4. All fuel feed and air control linkages are adjusted prior to switching the stoker over to the automatic control mode. During this adjustment, the settings are made at minimum fuel feed, maximum fuel feed, and several points between.

Normal Operation

1. Reasonably clean settling chambers are maintained in the furnace, breaching and heat traps, where cinders can accumulate.

2. The combustion control system is kept in proper adjustment and working freely.

3. The fans and fan blades are periodically cleaned, and any blades that may have become loose or damaged are repaired.

4. The grates are examined periodically to be certain that all air holes are open.

5. The fuel and air are maintained in proper proportion to the extent practicable so that fuel burns cleanly and the amount of smoke is minimized.

6. Ash present in the ash pits is removed as necessary in order to minimize any furnace draft upsets.

7. At one week intervals, or as operating experience indicates, the stoker and forced draft fan are stopped to clean out the siftings chamber(s).

8. After the siftings chambers have been cleaned, all access doors and ash pit doors are tightly closed and sealed to minimize air leakage.

9. At regular intervals, checks are made to identify air leaks at all air swept fuel distributor spout joints and between spout and mounting plate. If any leaks are detected, the joint is repaired with furnace cement as necessary.

10. At regular intervals, checks are made for air leaks between the air supply duct, damper housing and fuel distributor spouts. If any leaks are detected, the leaks are repaired with furnace cement.

11. 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.

12. Once per day, on the day shift, the boiler is given a walk-around inspection with the following items being checked and repaired as needed and in coordination with the production schedule:

    A. Fans
    B. Pumps
    C. Casing
    D. Ducting
    E. Electrostatic precipitator

13. On every shift, burners are inspected and cleaned if dirty.

14. On every shift, precautions are taken as necessary to control visible emissions of fugitive particulate matter (dust, bagasse, etc.)

15. The boiler operator will maintain steam rate at the 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 the highest possible excess air) in order to promote good combustion.

16. 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.

17. Bagasse moisture content will be maintained at or below 55%.

Shutdown of Boiler

1. When the furnace has cooled, the interior components of the stoker are inspected, and any slag or other obstructions to the air openings of the grates, rear tuyeres and apron tuyeres are removed.

2. Any slag formation on the front wall is removed and refractory under apron tuyeres are checked.

3. The boiler is inspected to identify any air leaks that may have developed between the grates and the walls of the boiler. Repair as needed.

4. The internal lower surfaces (removable wear liner) of the air swept fuel distributor spouts are inspected to determine wear rates. This will determine need for replacement during a scheduled outage.

ASP

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

April 9, 1996

Certified Mail–Return Receipt Requested

Mr. Murray T. Brinson.
Vice President, Sugar Processing
U.S. Sugar Corporation
Post Office Drawer 1207
Clewiston, Florida 33440

Dear Mr. Brinson:

Enclosed is a copy of an administrative order concerning the request for approval to use periodic EPA Method 9 opacity evaluations in lieu of the continuous opacity monitor required by 40 CFR 60 Subpart Db for visible emissions from Boiler No. 7.

If you have any questions about the above, please call Ramesh Menon at 904/488-6140, or write to me.

Sincerely,

Michael D. Harley, P.E., DEE
P.E. Administrator
Emissions Monitoring Section
Bureau of Air Monitoring and
Mobile Sources

/MH

Enclosure

cc: Pat Comer, FDEP
David Knowles, FDEP South District
David Buff, KBN

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	Permit No.	AC 26-238006
	)		PSD-FL-208
United States Sugar Corporation,	)		AO 26-242733
	)		
Petitioner.	)	ASP No.	95-B-01

ORDER ON REQUEST
FOR
ALTERNATE PROCEDURES AND REQUIREMENTS

Pursuant to Rule 62-297.620, Florida Administrative Code (F.A.C.), United States Sugar Corporation, petitioned for approval to use periodic EPA Method 9 opacity evaluations in lieu of a continuous opacity monitor for visible emissions from Petitioner's Boiler No. 7 (AC 26-238006/PSD-FL-208 and AO 26-242733) located in Hendry County.

Having considered Petitioner's written request and all supporting documentation, the following Findings of Fact, Conclusions of Law, and Order are entered:

FINDINGS OF FACT

1. Petitioner's Boiler No. 7 is an industrial boiler regulated under 40 CFR 60, Subpart Db which burns bagasse as the primary fuel and low sulfur No. 2 fuel oil as the supplemental fuel. Pursuant to 40 CFR 60.48b(a), Petitioner is required to install, calibrate, operate, and maintain a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere when burning No. 2 fuel oil.

2. The federally enforceable construction permit, permit number AC 26-238006/PSD-FL-208, limits Petitioner to an annual firing capacity of no more than 10 percent for No. 2 fuel oil.

3. On May 2, 1995, Petitioner specifically requested approval of a periodic EPA Method 9 evaluation protocol for Boiler No. 7 during those periods when No. 2 fuel oil is burned. [Exhibit 1]

4. Petitioner described the proposed opacity protocol as follows:

"A Method 9-trained and certified visible emission observer performs a 6-minute opacity test once a daylight shift during the period of the highest anticipated fuel oil firing rate.

A Method 9-trained and certified visible emission observer performs a 6-minute opacity test when Boiler No. 7 achieves the normal operational load after a cold boiler startup with No. 2 oil.

If the opacity readings exceed 10 percent, the observer continues the readings for another 12 minutes to obtain two additional data sets for a total of 3 data sets.

The observer logs in the reading results along with the date and time and submits the data to the Department's South District Office once per calendar quarter if distillate oil was fired during that quarter. As required by specific condition 24 of Air Construction Permit AC 26-238006/PSD-FL-208, fuel usage and fuel analysis data will be submitted to the Department's South District Office on a quarterly basis to verify that the 10 percent capacity limit is not exceeded." [Exhibit 1]

5. Petitioner further stated, "U.S. Sugar Corporation will follow the boiler manufacturer's maintenance schedule and procedures to assure that serviceable components are well maintained." [Exhibit 1]

6. As justification for the use of the alternate opacity monitoring procedure, Petitioner stated, "In light of the infrequency with which Boiler No. 7 will be burning No. 2 fuel oil and in light of the low ash content of No. 2 fuel oil emissions, U.S. Sugar requests the establishment and approval of the alternate opacity monitoring protocol set forth at Exhibit A, which has been deemed an acceptable alternative by U.S. EPA and Region IV." [Exhibit 1]

7. The Region 4 Office of the U.S. EPA has determined that an annual capacity factor of ten percent constitutes infrequent operation for purposes of alternative methods pursued under 40 CFR 60.13(i)(2). [Exhibit 2]

8. The Region 4 Office of the U.S. EPA recommends approval of Petitioner's request with minor revisions. [Exhibit 2]

9. Pursuant to the federally approved State Implementation Plan (SIP) [Rule 62-297.330(1)(b)3., F.A.C.], the minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit with an applicable opacity standard is twelve minutes.

CONCLUSIONS OF LAW

1. The Department has jurisdiction to consider Petitioner's request pursuant to Section 403.061, Florida Statutes (F.S.), and Rule 62-297.620, F.A.C.

2. Pursuant to Rule 62-297.340(2), F.A.C., the Department may

require Petitioner to conduct compliance tests that identify the nature and quantity of pollutant emission if, after investigation, it is believed that any applicable emission standard or condition of a permit is being violated.

3. Petitioner has provided reasonable justification that proposed periodic EPA Method 9 evaluations of opacity will provide a sufficient substitute for the required continuous opacity monitoring providing the capacity factor of 10 percent for combustion of No. 2 fuel oil is not exceeded and the applicable visible emission limiting standard in 40 CFR 60.43b(f) is not exceeded when Boiler No. 7 is operated on No. 2 fuel oil.

ORDER

Having considered Petitioner's written request and supporting documentation, it is hereby ordered that:

1. In lieu of continuous opacity monitoring, Petitioner may use the following procedure in order to determine the opacity of emissions when Boiler No. 7 burns No. 2 fuel oil:

1.1 An individual who is trained in the use of EPA Method 9 and currently certified as a visible emission observer by the State of Florida shall perform a twelve-minute opacity test once per daylight shift during the period that the highest oil firing rate occurs;

1.2 An individual who is trained in the use of EPA Method 9 and currently certified as a visible emission observer by the State of Florida shall perform a twelve-minute opacity test when the boiler achieves the normal operational load after a cold boiler startup with No. 2 fuel oil;

1.3 Observations required pursuant to 1.1 and 1.2 shall be made in accordance with the provisions of EPA Method 9;

1.4 The observer shall maintain a log which includes all of the information required by EPA Method 9 for each set of observations and the quantity of No. 2 oil being burned at the time of observation;

1.5 A copy of the observation log shall be submitted to the Department's South District Office once per calendar quarter if distillate oil was fired during that quarter. Information regarding fuel usage and fuel analysis shall also be submitted to the Department's South District Office on a quarterly basis to verify that the 10 percent capacity limit is not exceeded;

2. Petitioner shall follow the boiler manufacturer's maintenance schedule and procedures to assure that serviceable components are well maintained; and,

3. Petitioner shall install and operate a continuous opacity monitor if either the capacity factor of 10 percent for combustion of No. 2 fuel oil is exceeded or the applicable visible emission limiting standard in 40 CFR 60.43b(f) is not regularly complied with when Boiler No. 7 is operated on No. 2 fuel oil.

4. The Department reserves the right to require Petitioner to install and operate a continuous opacity monitor pursuant to 40 CFR 60.48b(a), if after investigation, if it is believed that a continuous opacity monitoring system is necessary to more accurately assess the compliance status of the affected source.

PETITION FOR ADMINISTRATIVE REVIEW

1. A person whose substantial interests are affected by the Department's decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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, Tallahassee, Florida 32399-3200, within 21 days of receipt of this Order. The petitioner shall mail a copy of the petition to the applicant at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

2. The petition shall contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, and the Department File Number;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by each petitioner, if any;

(e) A statement of facts which each petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement of which rules or statutes each petitioner contends require reversal or modification of the Department's action or proposed action; and,

(g) A statement of the relief sought by each petitioner, stating precisely the action each petitioner wants the Department to take with respect to the Department's action or proposed action.

3. If a petition is filed, the administrative hearing process

is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform with the requirements specified above and be filed (received) within 21 days of receipt of this notice in the Office of General Counsel at 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3200. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

4. This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3200; 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 of Appeal must be filed within 30 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 1st day of April, 1996 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

HOWARD L. RHODES
Director
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

(904) 488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a true copy of the foregoing was mailed to Mr. Murray T. Brinson, Vice President, Sugar Processing, United States Sugar Corporation, Post Office Drawer 1207, Clewiston, Florida 33440, on this 1st day of April 1996.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Martha Jane Weese 4/1/96

Clerk Date

fuel

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

August 15, 1995

Mr. Brian Beals, Chief
Source Evaluation Unit
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division
United States Environmental
Protection Agency, Region 4
345 Courtland Street, Northeast
Atlanta, Georgia 30365

RECEIVED
SEP 5 1995
Bureau of
Air Regulation

Re: United States Sugar Corporation~~, Clewiston, Florida~~
Boiler No. 7, Permit Number AC 26-238006, AO 26-242733
Request for Approval of an Alternate Opacity Monitoring Procedure

Dear Mr. Beals:

On May 2, we received a request from the above referenced facility to use an alternate opacity monitoring procedure for their Boiler Number 7. The affected source is an industrial boiler regulated under 40 CFR 60, Subpart Db which burns bagasse as the primary fuel and low sulfur No. 2 fuel oil as the supplemental fuel. Pursuant to 40 CFR 60.48b(a), the facility should install a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere when burning No. 2 fuel oil.

The federally enforceable construction permit, AC 26-238006, limits U.S. Sugar Corporation to an annual firing capacity of no more than 10 percent for No. 2 fuel oil. Pursuant to 40 CFR 60.13(i)(2), the company proposes to use an alternate opacity monitoring method based on the premise that the facility is infrequently operated on oil. The company cites John B. Ransic's (Director, Stationary Source Compliance Division, USEPA) memorandum of January 19, 1993, in support of their justification. The memorandum approves Emory University's request for an alternate opacity monitoring procedure for a Subpart Db boiler which was infrequently fired with No. 2 fuel oil. Although both the U.S. Sugar boiler and the boiler identified in the memorandum burn No. 2 oil on an infrequent basis, the primary fuels used at these sources are different. The boiler at Emory University uses natural gas as the primary fuel whereas the primary fuel for Boiler No. 7 at U.S. Sugar is bagasse.

Mr. Ransic's memorandum of January 19, 1993 allows Emory University to perform EPA Method 9 for a 6-minute period once a daylight shift during the period of the highest oil firing rate as well as when the boiler achieves the operational load after a cold boiler startup with No. 2 oil.

Pursuant to the federally approved State Implementation Plan (SIP) [Rule 17-297.330(1)(b)3., Florida Administrative Code], the minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit with an applicable opacity standard is twelve minutes.

Please review the attached material and provide guidance concerning appropriate opacity monitoring requirements. Also, please advise as to whether the minimum observation period should be twelve minutes based on the above referenced provision of the SIP. We would appreciate written comments by September 10. If you have any questions, please call Ramesh Menon or me at 904/488-6140.

Sincerely,

Michael D. Harley

Michael D. Harley, P.E., DEE
Administrator
Emissions Monitoring Section
Bureau of Air Monitoring and
Mobile Sources

MDH/rm

cc: Dotty Diltz
Al Linero
Ramesh Menon
David Knowles

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

August 1, 1995

Certified Mail - Return Receipt Requested

Mr. David A. Buff, P.E.
Principal Engineer
KBN Engineering and Applied Sciences, Inc.
6241 Northwest 23rd Street, Suite 500
Gainesville, Florida 32653-1500

Re: United States Sugar Corporation - Request for Approval of Alternate Opacity Monitoring Procedure - AC 26-238006

Dear Mr. Buff:

The Department has received the additional information requested in our letter of June 7, 1995.

Requests for approval of alternate opacity monitoring procedures are evaluated on a case-by-case basis and copies of each request are sent to the Region 4 office of the EPA, DEP district offices and approved local programs for review and comment. Until an Order approving an alternate procedure is signed, compliance with the applicable emission limitations is to be determined using the procedures described in 40 CFR Subpart Db.

If you have any questions, please call Ramesh Menon at 904/488-6140 or write to me.

Sincerely,

for Michael D. Harley, P.E., DEE
Administrator
Emissions Monitoring Section

MDH/rm

cc: Dotty Diltz
Al Linero STATE
Ramesh Menon
David Knowles SD

KBN

RECEIVED

MAY 8 1995

Bureau of Air Regulation

May 2, 1995

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: United States Sugar Corp. - Clewiston Boiler No. 7
DEP File No. AC26-238006/PSD-FL-208
Request for Alternate Opacity Monitoring Procedure

Dear Mr. Fancy:

On behalf of U.S. Sugar Corporation, we respectfully request that the Department approve an alternate opacity monitoring procedure for Clewiston Boiler No. 7 pursuant to 40 CFR 60.13(i)(2) and Rule 62-297.620, F.A.C.

Clewiston Boiler No. 7 will be an industrial boiler regulated under 40 CFR 60, Subpart Db. It will fire bagasse as its primary fuel and very low sulfur No. 2 distillate oil ("No. 2 fuel oil") as a supplemental fuel.

When burning No. 2 fuel oil, Boiler No. 7 is subject to the opacity standards in 40 CFR 60.43b(f)[1] and Rule 62-296.800(2)(a)3, F.A.C.[2] Specific Condition 9 of the above-referenced construction permit limits the annual capacity for No. 2 fuel oil to no more than 10 percent. This is a federally-enforceable requirement.

<u>40 CFR 60.13(i)</u>

40 CFR 60.13(i)(2) allows facility owners or operators to propose alternative opacity monitoring methods for facilities that are operated infrequently.[3]

---

[1] 40 CFR 60.43b(f) prohibits the atmospheric discharge of gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

[2] Rule 62-296.800(2)(a)3, F.A.C. adopts and incorporates by reference 40 CFR 60, Subpart Db.

[3] 40 CFR 60.13(i)(2) states:

KBN ENGINEERING AND APPLIED SCIENCES, INC.

6241 Northwest 23rd Street, Suite 500, Gainesville, Florida 32653-1500, 904-336-5600 FAX 904-336-6603
5405 West Cypress Street, Suite 215, Tampa, Florida 33607, 813-287-1717 FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910 FAX 407-994-9393
7785 Baymeadows Way, Suite 105, Jacksonville, Florida 32256, 904-739-5600 FAX 904-739-7777
1616 'P' Street N.W., Suite 450, Washington, D.C. 20036, 202-462-1100 FAX 202-462-2270

In a memorandum dated January 19, 1993, John B. Rasnic, Director, Stationary Source Compliance Division, USEPA (copy enclosed), confirmed that a 10 percent annual capacity factor can reasonably be considered "infrequent operation." Accordingly, a Subpart Db boiler with a 10 percent annual capacity for No. 2 fuel oil would be allowed to use an alternative opacity monitoring method.

The Rasnic Memorandum outlines one possible alternative monitoring program for "infrequently operated" facilities that is considered acceptable under 40 CFR 60.13(i)(2). U.S. Sugar proposes to adopt this alternative monitoring protocol whenever No. 2 Fuel Oil is being combusted in Boiler No. 7. (See Exhibit A).

Rule 62-297.620, F.A.C.

Rule 62-297.620, F.A.C. allows owners or operators of emissions units to request an alternate emissions test methodology for an emissions unit by demonstrating that the proposed alternative is adequate to demonstrate compliance with applicable emissions limiting standards.

U.S. Sugar requests that the Department approve the proposed alternative opacity monitoring protocol for Boiler No. 7 set forth at Exhibit A.

Currently, no independent Florida rule in Chapter 62-297, F.A.C. requires the installation of a continuous monitoring device to measure the opacity of emissions from Clewiston Boiler No. 7. Rule 62-297.500, F.A.C., cited in specific condition 9 of the above-referenced construction permit, was repealed on November 23, 1994. Thus, such monitoring is required only under Subpart Db, which has been incorporated by reference in the Florida Rules.

In light of the infrequency with which Boiler No. 7 will be burning No. 2 fuel oil and in light of the low ash content of No. 2 fuel oil emissions, U.S. Sugar requests the establishment and approval of the alternate opacity monitoring protocol set forth at Exhibit A, which has been deemed an acceptable alternative by U.S. EPA and Region IV.

"After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(2) Alternative monitoring requirements when the affected facility is infrequently operated."

Please contact me or Bob Van Voorhees (202-508-6014) if you have any questions about this request.

Sincerely,

David A. Buff

David A. Buff, P.E.
Principal Engineer

Enclosure

cc: Al Linero, DEP
Mike Harley, DEP
Cleve Holladay, DEP
David Knowles, DEP South District
Jewell Harper, EPA Region IV
Stan Kukier, EPA Region IV
John Bunyak, NPS
Murray Brinson, U.S. Sugar
Peter Briggs, U.S. Sugar
Don Griffin, U.S. Sugar
Robert Van Voorhees, Bryan Cave
File (2)

Department of Environmental Protection

ROUTING AND TRANSMITTAL SLIP

To: (Name, Office, Location)

1. Dotty Diltz
2. Mike Harley

Remarks:

Attached for your action is a request for an Alternate Sampling Procedure (ASP) from U.S. Sugar Corporation. We have no objection to the request. Let us know if an ASP is applicable as well as your final action so we can, if necessary, amend the affected permit. If we need to amend the permit, we will need to advise the applicant to send us the $250 permit amendment fee so there is no delay in processing the request.

Kim - for Patty's Files. I added to docket. Al

From	Date 5/09/95
Al Linero	Phone 1-9532

UNITED STATES SUGAR CORPORATION
Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121 Telex: 510-952-7753

February 15, 1995

BY UPS OVERNIGHT

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Fl. 32399-2400

Re: United States Sugar Corp. - Clewiston Boiler No. 7
DEP File No. AC26-238006/PSD-FL-208
Request to Amend Construction Permit

Dear Mr. Fancy:

U. S. Sugar Corporation appreciates the time and effort the Department and its staff spent on the above-referenced permit and appreciates the cooperative manner in which we were able to work with the Department to have this permit issued.

We have reviewed the final permit, and recognize that several provisions need to be corrected or clarified to avoid future misunderstandings. First, U. S. Sugar requests that the Department correct the expiration date of the permit. As properly stated in the Final Determination, the permit expiration date should read March 31, 1998 rather than September 1, 1996. Additional revisions and clarifications requested are as follows:

A. Specific Condition 10

All ~~stationary fuel oil burning equipment~~ boilers at the plant shall be equipped with integrated fuel oil flow meters or continuous recorders to measure the amount of fuel oil consumed by the equipment. Fuel oil meter readings on ~~all fuel oil consuming equipment~~ the boilers shall be read and logged at least once every three hours, unless fuel oil consumption ~~for the equipment~~ is recorded continuously, and these records shall be kept for at least five years for Department inspection. Each meter shall be calibrated annually by a method approved by the Department.

EXPLANATION:

10.1

Permits for stationary fuel-oil burning equipment other than the boilers at the plant (i.e., Diesel Electric Generators Nos. 1 & 2) contain different requirements. To avoid any appearance of conflicting requirements for measuring, monitoring and record keeping under this pre-existing Construction Permit No. AC26-259722, U. S. Sugar requests that the Department amend specific condition 10 as indicated.

B. Specific Condition 17 (relevant part)

~~In such circumstances, the tests shall be conducted as close to each other as is possible. In accordance with 40 CFR 60.486 the permittee shall install calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions. The monitoring devise shall meet the applicable requirements under Chapter 62-297, F.A.C., and 40 CFR 60, Appendix B.~~

EXPLANATION:

17.1

This paragraph contains an erroneous reference to 40 CFR 60.486 [Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry]. Presumably, a reference to 40 CFR 60.48b was intended. Since this requirement is already expressly addressed in Specific Condition 9, Specific Condition 17 should be deleted in its entirety.

C. Specific Condition 18

Pursuant to Rule 62-296.310 (3), F.A.C., reasonable precautions shall be used to minimize unconfined emissions of particulate matter when reclaiming dry bagasse for the boiler. Reasonable precautions may include but shall not be limited to the following:

(1) Paving and maintenance of roads, parking areas and yards.
(2) Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
(3) Application of asphalt, water, oil, chemicals or dust suppressants to unpaved roads, yards, open stock piles and similar sources.

(4) Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the source to prevent reentrainment, and from building or work areas to prevent particulate from becoming airborne.
(5) Landscaping or planting of vegetation.
(6) Use of hoods, fans, filters, and similar equipment to contain capture and/or vent particulate matter.
(7) Confining abrasive blasting where possible.
(8) Enclosure or covering of conveyor systems.
(9) Wind breaks shall be installed around the dry bagasse ~~load-out~~ storage area.
(10) Floors in the enclosed area shall be cleaned periodically.
(11) ~~Loading~~ Storage areas for bagasse not currently being used as fuel shall be cleaned or wetted as needed to minimize fugitive dust.
(12) Trucks transporting bagasse shall be covered.

EXPLANATION:

18.1

Words were inadvertently omitted from the language in F.A.C. Rule 62-296.310(3) (c) (6) and should be added.

18.2

U. S. Sugar understands that (3) does not apply to the bagasse fuel storage area during the operating season. Wetting or otherwise treating this bagasse will inhibit its combustion. We would appreciate receiving confirmation of this understanding.

18.3

The bagasse fuel storage area is addressed in (9) and (11). A phrase should be added to (11) to clarify this understanding.

We hope that adequate explanations have been provided for the requested amendments. Please call me (813-983-8121) or Bob Van Voorhees (202-508-6014) if you have any questions about the requested amendments. Thank you again for your assistance.

Sincerely,

UNITED STATES SUGAR CORPORATION

Murray T. Brinson
Vice President, Sugar Processing

cc: David Knowles, DEP, South District
Bert Starrett, USSC
Donald Griffin, USSC
Peter Briggs, USSC
David Buff, KBN
Bob Van Voorhees, Bryan Cave

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

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Bureau of Air Regulation

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JAN - 6 1995

Mr. Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: United States Sugar Corporation (USSC), Clewiston, Hendry County, Florida (PSD-FL-208)

Dear Mr. Fancy:

This is to acknowledge receipt of USSC's response to United States Environmental Protection Agency (USEPA) - Region 4's comment regarding emissions netting calculations by copy of a letter dated December 8, 1994, from Mr. David A. Buff of KBN Engineering and Applied Sciences, Inc. (KBN) to Ms. Teresa M. Heron of your staff. Additional information regarding the particulate matter impact analyses was received by a letter dated December 15, 1994, from Mr. Robert F. Van Voorhees of Bryan Cave. The proposed project consists of the addition of a new 738 mm BTU/hr bagasse/fuel oil fired spreader stoker/vibrating grate boiler (No. 7) at the Clewiston mill. As discussed between Mr. Willard Hanks of your staff and Mr. Stan Kukier of my staff on December 20, 1994, we have the following additional comment regarding emissions netting calculations and the Prevention of Significant Deterioration (PSD) applicability analysis for particulate matter:

> Emissions netting calculations included in Table II of a letter dated September 23, 1994, from Mr. Buff to Ms. Heron of your staff indicates that Clewiston Boiler No. 7 particulate matter emissions are not subject to PSD review. The net emissions increases listed in Table II for particulate matter (PM) and inhalable particulate matter (PM_{10}) are 17.2 and 12.2 tons per year (TPY), respectively. However, contemporaneous emissions decreases for Boiler Nos. 5 and 6 included in Table II netting calculations are based on an allowable PM emission rate. Contemporaneous decreases calculated by KBN for Boiler Nos. 5 and 6 are as follows based on an allowable PM emission rate limit of 0.3 lb/mm BTU.

TABLE I

Contemporaneous Decreases (TPY)

Criteria Pollutant	Boiler 5	Boiler 6	Totals
PM	52.8	59.3	112.1
PM_{10}	47.6	53.3	100.9

Page A.41 of the New Source Review Workshop Manual, Draft October 1990 Edition, indicates that source-specific allowable emissions may be used only in certain limited circumstances where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level. Stack test results for particulate matter were requested and received via fax from Mr. Hanks on December 15, 1994. Revised netting calculations using actual 1992 and 1993 stack test results and annual heat input values from the September 23, 1994, Table IIa note for both Boiler Nos. 5 and 6 are as follows.

TABLE II

Annual PM/PM_{10} Emissions

Emission Unit	Stack Test Date	PM Test Result (lb/mm BTU)	Heat Input (mm BTU/ yr)	PM Emissions (TPY)	PM_{10} Emissions (TPY)[1]
Boiler 5	1/30/92	0.169	349,000	29.5	
	3/12/93	0.14	356,000	24.9	
Total				54.4	
Average				27.2	24.5
Boiler 6	2/5/92	0.153	423,000	32.4	
	2/3/93	0.184	367,000	33.8	
Total				66.2	
Average				33.1	29.8
Total - Boiler 5 and 6				60.3	54.3

1 Assumes PM_{10} = 0.90(PM) based on limited source testing conducted on bagasse boilers.

TABLE III

U.S. Sugar Clewiston Boiler No. 7 - PSD Applicability Analysis

Criteria Pollutant	Total Emissions Decreases (TPY)	Boiler No.7 Emissions Increases	Net Emissions Increase (TPY)	PSD Significant Emission Rates	PSD App-lies ?
PM	60.3	129.3	69.0	25	Yes
PM_{10}	54.3	113.1	58.8	15	Yes

Actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. As shown in Table II above, contemporaneous emission decreases are significantly less for Boiler Nos. 5 and 6 when actual emissions data and annual heat input values are used as the basis of calculation. The revised PSD applicability analysis in Table III indicates that the applicant may not "net out" of PSD applicability for particulate matter emissions increases associated with the proposed major modification. The applicant should reevaluate PSD applicability for particulate matter emissions, and perform or revise air quality and Best Available Control Technology (BACT) analyses accordingly.

We also have the following comment regarding BACT for Boiler No. 7 particulate matter emissions:

Based on information previously submitted by USSC, as well as other recent BACT determinations for bagasse fired boilers, USEPA - Region 4 would recommend that electrostatic precipitator (ESP) technology be considered BACT for control of Clewiston mill Boiler No. 7 particulate emissions. However, the applicant should clarify the basis of both the allowable PM and PM_{10} emission limits listed on page 5 of 11 of the draft permit included in the preliminary determination package dated October 24, 1994. The draft permit lists allowable PM and PM_{10} emission limits of 0.04 and 0.035 lb/mm BTU, respectively, for bagasse fuel firing. Identical allowable PM and PM_{10} emission limits of 0.04 lb/mm BTU are listed for Boiler No. 7 No. 2 fuel oil firing. A letter dated September 9, 1994, from Mr. Van Voorhees to Ms. Heron indicates that less stringent emission limits were selected since the original applicability analysis showed that particulate matter emissions would not be subject to PSD requirements. Page 3 of a letter dated June 27, 1994, from Mr. Murray T. Brinson of USSC to Mr. John C. Brown of your staff indicates that at least one ESP vendor can guarantee a particulate matter emission rate limit of 0.03 lb/mm BTU for the proposed Clewiston mill Boiler No. 7. A particulate emission rate limit of 0.03 lb/mm BTU has recently been determined BACT for several new biomass/fossil fuel fired boilers at both Okeelanta and Osceola sugar mills. ESP systems at both facilities have collection efficiencies in excess of 98%. Beryllium is also condensed and captured by the ESP systems at Okeelanta and Osceola mills.

If you have any additional questions, please contact Mr. Stan Kukier of my staff at (404) 347-3555, voice mail box extension 4143.

Sincerely yours,

Jewell A. Harper
Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

KBN

December 8, 1994

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JAN 10 1995

Bureau of
Air Regulation

Ms. Teresa Heron, P.E.
Florida Department of
Environmental Protection
111 South Magnolia, Suite 4
Tallahassee, FL 32301

RE: United States Sugar Corporation
Clewiston Boiler No. 7

Dear Ms. Heron:

Thank you for forwarding a copy of the comments received from U.S. EPA Region IV (EPA), on the proposed permit for U.S. Sugar Clewiston Boiler No. 7. U.S. Sugar Corporation (U.S. Sugar) has reviewed the comments and has discussed them with Mr. Stan Kukier at EPA to make sure that we have a clear understanding of his concerns.

With respect to his comment about the "predetermined limits for cost effectiveness," U.S. Sugar understands that EPA has not established a rigid cutoff for cost effectiveness determinations and that these are made on a case-by-case basis. We also understand from our discussion with Mr. Kukier that this comment was made for informational purposes and was not intended to limit EPA's acceptance of BACT determinations made by Florida Department of Environmental Protection (FDEP).

With respect to the second comment, Mr. Kukier indicated that this comment was included to ensure that the netting determinations and calculations made by KBN, as reflected in the FDEP's technical evaluation and preliminary determination, had been made in accordance with the applicable EPA requirements and guidelines. This letter will serve to confirm that KBN followed the procedures established in the October 1990 New Source Review Workshop Manual, entitled "Prevention of Significant Deterioration and Nonattainment Area Permitting." Accordingly, KBN included all source-wide creditable and contemporaneous (occurring within 5 years prior to the commencement of construction) emissions increases and decreases in the netting calculation reflected in our letter dated September 23, 1994, (copy enclosed), and in Table 2 of the technical evaluation and preliminary determination. By way of clarification, Table 2 focuses on a comparison between the operation of Boilers Nos. 5 and 6 and the new proposed Boiler No. 7 because these are the only contemporaneous decreases and increases in actual emissions that are appropriate to take into account in making the netting determination.

14015A1.7

This letter should serve to satisfy the concerns expressed in the EPA letter. We are forwarding a copy of the letter to Mr. Kukier for his review. Accordingly, we trust that the FDEP can proceed with issuance of the final permit for Clewiston Boiler No. 7.

Sincerely,

David A. Buff

David A. Buff, P.E.
Principal Engineer

P.E. #19011
SEAL

Enclosure

cc: Stan Kukier, U.S. EPA Region IV
Don Griffin
Murray Brinson
Peter Briggs
Bob Van Voorhees
File (2)

DB/mlb

O. Knowles, SF Dist.
J. Harper, EPA
J. Bunyak, NPS

BRYAN CAVE

700 THIRTEENTH STREET, N.W.
WASHINGTON, D.C. 20005-3960
(202) 508-6000
FACSIMILE: (202) 508-6200

ST. LOUIS, MISSOURI
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KANSAS CITY, MISSOURI

IRVINE, CALIFORNIA
SANTA MONICA, CALIFORNIA
OVERLAND PARK, KANSAS
LONDON, ENGLAND
RIYADH, SAUDI ARABIA
FRANKFURT AM MAIN, GERMANY

ROBERT F. VAN VOORHEES

DIRECT DIAL NUMBER
(202) 508-6014

December 15, 1994

BY FEDERAL EXPRESS

Mr. Stan Kukier
U.S. Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Re: United States Sugar Corporation -
Clewiston Bill Boiler No. 7 PM Analysis

Dear Mr. Kukier:

We have spoken with David Buff regarding his discussion with you of the PM analyses conducted as part of the Clewiston Boiler No. 7 construction permit application. As Mr. Buff indicated, U.S. Sugar prepared PM impact analyses for Boiler No. 7 before deciding to use an ESP to control PM emissions. As demonstrated by the enclosed materials, the impact analyses were submitted as part of the initial PSD application in September 1993, and in revised form earlier this year. Thus, even though Boiler No. 7 "netted out" of PSD for PM after the decision to use an ESP was made, all of the impact analyses required under PSD had already been conducted and submitted to the Florida Department of Environmental Protection for their consideration.

Please call me if we can provide you with any additional information.

Sincerely,

Robert F. Van Voorhees

Robert F. Van Voorhees

cc: Teresa Heron, P.E., DEP
Murray Brinson, U.S. Sugar
Peter Briggs, U.S. Sugar
David Buff, P.E., KBN

Enclosures: Letter from Jewell Harper, Region IV to Clair Fancy, DEP, dated November 30, 1994.

cc: J. Bunyak, NPS
D. Knowles, S Dist.

Letter from Robert Van Voorhees, Bryan Cave to Teresa Heron, DEP, dated September 9, 1994.
Letter from James Coleman, National Park Service to Clair Fancy, DEP, dated June 28, 1994.
Letter from Murray Brinson, U.S. Sugar to John Brown, DEP, dated June 27, 1994.
Letter from Robert Van Voorhees, Bryan Cave to John Brown, DEP, dated June 7, 1994.
Letter from Peter Kroll, ICF Kaiser to John Brown, DEP, dated May 10, 1994.

Post-it® Fax Note 7671	Date 12-5-94	# of pages 3
To Peter Oppenheimer	From [illegible]	
Co./Dept.	Co.	
Phone #	Phone # 404/[illegible]	
Fax # 202/508-6200	Fax #	

UNITED STATES ENVIRO[NMENTAL PROTECTION AGENCY]
R[EGION IV]
345 COUR[TLAND STREET]
ATLANTA

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RECEIVED
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Bureau of Air Regulation

Mr. Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: United States Sugar Corporation (USSC), Clewiston, Hendry County, Florida (PSD-FL-208)

Dear Mr. Fancy:

This is to acknowledge receipt of your preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the major modification to the above referenced sugar cane processing facility by your letter dated October 24, 1994. The proposed project consists of the addition of a new 738 mm BTU/hr bagasse/fuel oil fired spreader stoker/vibrating grate boiler at the Clewiston mill. As discussed between Mr. Martin Costello of your staff and Mr. Stan Kukier of my staff on November 3, 1994, we have reviewed the package as submitted and have no adverse comments regarding the Best Available Control Technology (BACT) determination.

We agree that electrostatic precipitator (ESP) technology may be recommended as BACT for control of boiler particulate and beryllium emissions. The 0.04 lb/mm BTU particulate matter (PM) emission limit is significantly lower than the 0.15 and 0.1 lb/mm BTU PM emission limits proposed in the original PM BACT determination for bagasse and No. 6 fuel oil firing, respectively. The use of very low-sulfur No. 2 fuel oil ($\leq$ 0.05 percent sulfur by weight) may be considered representative of BACT for control of sulfur dioxide (SO_2) and sulfuric acid mist emissions. We also agree that good combustion practices may be recommended as BACT for Boiler No. 7 carbon monoxide (CO) and volatile organic compound (VOC) emissions. The use of low-nitrogen No. 2 fuel oil ($\leq$ 0.015 percent nitrogen by weight), overfire air, and good combustion practices may be considered BACT for control of boiler nitrogen oxides (NO_x) emissions. The boiler will also be equipped with low-NO_x burner technology. The heat input provided by the No. 2 fuel oil will not exceed ten percent of the total annual heat input to the new Clewiston No. 7 boiler. The maximum fuel oil sulfur and nitrogen contents originally proposed by USSC were 0.5 and 0.3 weight percent,

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respectively. Boiler No. 7 will not be operated as a cogeneration unit.

However, as discussed between Ms. Teresa Heron of your staff and Mr. Stan Kukier of my staff on November 8, 1994, we have the following comments related to cost effectiveness and emissions netting.

1. Page 10 of a letter dated February 22, 1994, from Mr. Peter Kroll of ICF Kaiser Engineers, Inc., to Mr. John Brown of your staff, indicates that the United States Environmental Protection Agency (USEPA) has set an upper \$/ton of NO_x removed limit on cost effectiveness for evaluating NO_x emission control technologies. This is incorrect. USEPA - Region 4 does not have predetermined limits for cost effectiveness when evaluating the feasibility of control technologies for any criteria pollutant. All BACT determinations are made strictly on a case-by-case basis.

2. Additional information must be provided by the applicant before an analysis of the emissions netting calculations may be completed. In order to correctly determine the net emissions increase of any criteria pollutant for PSD applicability, it is necessary to include <u>all</u> source-wide creditable and contemporaneous emissions increases and decreases in the netting calculations. Table 2 on page 2 of the BACT determination includes only emissions decreases associated with the proposed operation of Boiler Nos. 5 and 6 in a standby mode. A source may not selectively decide which applicable source specific emissions increases and decreases to include in the netting calculations. Creditable and contemporaneous emissions increases and decreases associated with the operation of Boiler Nos. 1, 2, 3, and 4 must be included. The applicant must also clarify the basis of all criteria pollutant emissions increases and decreases. Decreases are creditable reductions in actual emissions from an emissions unit that are, or can be made, federally enforceable. An emissions increase or decrease is creditable only if it has not been previously relied upon in issuing a PSD permit for USSC, and the permit is still in effect when the increases in actual criteria pollutant emissions from the addition of Boiler No. 7 occur. It is also unclear from information provided in the preliminary determination package if all criteria pollutant emissions limitations contained in existing operating permits for all USSC Clewiston facility emissions units are federally enforceable.

The proposed No. 7 boiler will be subject to the requirements of 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

Thank you for the opportunity to comment on this package. If you have any questions, please contact Mr. Stan Kukier of my staff at (404) 347-3555, voice mail box extension 4143.

Sincerely yours,

Jewell Grubbs for

Jewell A. Harper
Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Dewy
C. Holladay
D. Knowles, S Dist.
J. Bunyal, NPS
D. Buff, KBN
CHF/SB

BACT proposed for nitrogen oxides (NO_x), the latter package does not. Use of video camera recording as an alternative opacity monitoring method is unacceptable since it would not provide opacity data in terms of the applicable standard.

The monitoring program outlined on page two of the memorandum dated January 19, 1993, as well as some similar programs, may be considered acceptable only for industrial boilers firing No. 2 oil on an infrequent basis. Alternative opacity monitoring plan requests for infrequently operated industrial boilers fired with heavier oils will be subject to separate determinations by the EPA. Copies of any other alternative Clewiston Boiler No. 7 opacity monitoring method proposals should be submitted to EPA for review.

Thank you for the opportunity to review and comment on this alternate opacity monitoring procedure. If you have any questions, please contact Mr. Stan Kukier of my staff at (404) 347-3555, voice mail box extension 4143.

Sincerely yours,

Jewell A. Harper
Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

Enclosure

cc: J. Heron
M. Harley
D. Knowles, SF Dist.
J. Bunyak, NPS
D. Buff, KBN
C. Holladay

UNITED STATES SUGAR CORPORATION
Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121

November 3, 1994

RECEIVED
NOV 9 1994
Bureau of
Air Regulation

CERTIFIED MAIL NO. P-288-952-958

Mr. John C. Brown, Jr., P.E.
Administrator
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl. 32399-2400

Subject: Comments on Proposed Permit and Technical Determination for United States Sugar Corp. -- Clewiston Boiler No. 7 AC26-238006 and PSD-FL-208

Dear Mr. Brown:

Thank you for the opportunity to review the proposed PSD permit and the Technical Evaluation and Preliminary Determination for the construction/installation of Clewiston Boiler No. 7. The United States Sugar Corporation ("U. S. Sugar") offers the following comments on these documents, and requests the following specific revisions:

A. Expiration Date: U. S. Sugar requests and expiration date of March 31, 1998 rather than September 1, 1996. Initially, we anticipate that Boiler No. 7 will be operated only during the sugar cane processing crop season, which falls between October 1 and March 31. We do not anticipate that actual construction work on the boiler will be completed very much in advance of December 31, 1996. Initial startup and debugging work will proceed for the remainder of the 1996-97 crop season and may be completed by March 31, 1997. This means that operation to achieve full capacity will not begin until the start of the 1997-98 crop season in October 1997, and full commissioning of the boiler, including compliance testing will proceed during the 1997-98 crop season and be completed by March 31, 1998. Under no circumstances do we anticipate that the boiler will be fully constructed, commissioned and tested by September 1, 1996.

B. The second sentence should be deleted from Specific Condition 11. The limitation placed on the use of the boiler in that sentence exceeds the restriction set forth in the regulations cited as authority for the limitation. The regulations in 40 CFR Part 60, Subpart Da do not prohibit the sale of electricity generated by an industrial boiler to any utility power distribution system at the levels specified in the second sentence. 40 CFR § 60.41a simply provides that any boiler constructed for the purpose of providing more than one-third of its potential electric output capacity and more than 25 MW to any utility power distribution system is subject to the NSPS for electric utility boilers. The question is one of intended use at the time of permitting. U. S. Sugar has no intent to use the boiler to supply electricity to any utility power distribution systems at levels that exceed these criteria. Moreover, to exceed the criteria, it would be necessary to be planning to supply more than 25 MW, or more than 70% of the potential electric output capacity of the boiler since the criterion is two-fold and conjunctive.

Accordingly, the sentence should be deleted [or, at the very most, U. S. Sugar could be asked to provide notice to the Department if it ever does supply electricity at a rate that exceeds 25 MW. This would allow the Department to assess whether or not it wants to assert at that time that the boiler was, in fact, constructed with the intent of supplying electricity at such a rate to any utility power distribution system.]

{NOTE: There is a third alternative -- namely, requesting that the sentence be revised to read: "Not more than 25 MW electricity output shall be supplied to any utility power distribution system." If this boiler is incapable of generating 75 MW, that limitation should be completly sufficient.}

C. Specific Condition No. 14 should be revised to provide that stack tests be performed "no later than 180 operating days after initial (I) startup." It is necessary to state this requirement in terms of operating days because U. S. Sugar operates its boilers on a seasonal basis only during the sugar cane crop harvesting season. Initially, Boiler No. 7 will also be operated on a seasonal basis. Thus, it is quite possible that the boiler will be started up during the latter portion of the 1996-97 crop season, but will not achieve maximum capacity until sometime during the 1997-98 crop season. To allow for this contingency, the 180-day requirement should be stated in terms of operating days.

D. Specific Condition No. 18 should be revised to read as follows:

I think there is a good argument for keeping emissions down - ~~[illegible]~~ to include when winds are strong

"Visible emission from the bagasse handling systems shall not exceed 10 percent opacity over any 6 minute period as measured by EPA Reference Method 9, provided, however, that this visible emissions limit shall not apply during periods of high winds (wind speed of 18 miles per hour or greater) if reasonable precautions (covered conveyors, windbreaks, and the height of drop points are minimized) to control fugitive emissions have been taken. The company shall maintain a meteorological instrument to record the wind speed at the plant which shall be located at its Research Center, about one mile "south" of the Clewiston Mill.

This is the exact wording of the requirement as it appears in the current permit for Clewiston Boiler No. 4. Since the same bagasse handling system will be used for both boilers, and since this is the established requirement under which U. S. Sugar and the Department have operated in the past, the same provision should be retained for purposes of consistency. There is no evidence suggesting that this provision has not been adequate to satisfy the Department's requirements.

E. Several corrections should be noted for the Technical Evaluation and Preliminary Determination.

1. On page 3, in line 10 of the paragraph under the heading "III.1 Background Information," the reference should be to No. 6 fuel oil, rather than No. 2 fuel oil, since No. 6 fuel oil is the only fuel oil currently burned in the existing boilers.

Check w/EPA - Do they mean 180 oper. days? ✓

What is the basis of the 10% opac. rule, BACT, ? Does the rule on BACT address wind speed?

Look into this w/ M.H. Why should w/s be a factor. Does that invalidate the test method?

2. On page 4, in line 5 of the first paragraph under the heading "V.1 control Technology Review," the statement should be corrected to read "existing bagasse fired Boilers No. 5 and No. 6," since Boilers No. 5 and 6 are exclusively bagasse fired boilers. Neither one of these boilers burns fuel oil.

Again, we thank you for the opportunity of providing these comments with the hope that our reasons for requesting specific changes are sufficiently clear and understandable. If you have any questions or want to discuss these comments, please call me at (813) 983-8121 or Bob Van Voorhees at (202) 508-6014. We look forward to receiving the final permit and to working with the Department during the commissioning and testing process for this boiler.

Very truly yours,

UNITED STATES SUGAR CORPORATION

Murray T. Brinson
Vice President
Sugar Processing

MTB:jt

CC: Mr. C. H. Fancy, P.E.
Mr. David Knowles
Mr. Robert Van Voorhees
Mr. David Buff
Mr. Peter Briggs
Mr. Donald Griffin

UNITED STATES SUGAR CORPORATION
Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121

November 3, 1994

RECEIVED
NOV 9 1994
Bureau of
Air Regulation

CERTIFIED MAIL NO. P288-952-957

Mr. Clair Fancy, P.E.
Bureau Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Fl. 32399-2400

RE: U S. Sugar Corporation - New Boiler No. 7
Proposed Construction/Installation Permit
No. AC26-28006 and PSD-FL-208

Dear Mr. Fancy:

We are enclosing an Affidavit of Publication certifying that the Notice of Proposed Agency Action included with your letter dated October 24, 1994 was duly published in the legal section of the November 2, 1994 issue of *The Clewiston News* newspaper.

Very truly yours,

UNITED STATES SUGAR CORPORATION

Donald Griffin

DG:jt
Enclosure

cc: Mr. John C. Brown, Jr.
Mr. David Knowles
D. Buyon
C. Holladay
D. Knowles, S F Dist
G. Harper, EPA
J. Bunyak, NPS

The Clewiston News

Published Weekly Clewiston, Florida

AFFIDAVIT OF PUBLICATION

State of Florida
County of Hendry

Before the undersigned authority, personally appeared Richard Hitt, who on oath says he is the Publisher 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

November 2, 1994

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.

Richard Hitt

Sworn to and subscribed before me this 2nd day of November, A.D. 19 94.

B K Christiansen

Notary Public

OFFICIAL NOTARY SEAL
B K CHRISTIANSEN
NOTARY PUBLIC STATE OF FLORIDA
COMMISSION NO. CC289381
MY COMMISSION EXP. JUNE 27,1997

Lyons Printing

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENT PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT
AC26-238006
PSD-FL-208

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit to the U.S. Sugar Corporation, P.O. Box 1207, Clewiston, Florida 33440, to install a 738 MMBtu/hr bagasse/fuel oil fired boiler. The No. 2 fuel oil (maximum 0.05% sulfur content and 0.015% nitrogen content, by weight)fired in the new Boiler No. 7 will be limited to 10% of the total potential heat input to the boiler in any calendar year. The proposed facility will be located at the U.S. Sugar Corporation's sugar mill on W.C. Owens Avenue and Clewiston Street, Clewiston, Hendry County, Florida. The increased emissions from the boiler will be offset by the reduction in emissions from the existing boilers (No. 5 and No. 6). Boilers No.5 and No.6 will be on standby when the new Boiler No.7 is in operation. The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations for the following pollutants: sulfur dioxide, nitrogen oxides, volatile organic compounds, sulfuric acid mist and beryllium. A determination of Best Available Control Technology (BACT) was required for these pollutants. The maximum predicted PSD Class II sulfur dioxide increments consumed by all sources, including this project, after this project is constructed are the following: 3.96 ug/m3, annual average, or 20% of the avaiable annual increment of 20 ug/m3; 36.7 ug/m3, 24-hour average, or 40% of the available 24-hour increment of 91 ug/m3; and 203 ug/m3, 3-hour average, or 40% of the available 3 hour increment of 512 ug/m3. The maximum predicted PSD Class I sulfur dioxide increments consumed are the following: 0.39 ug/m3, annual average or 20% of the available annual increment of 2.0 ug/m3; 3.82 ug/m3, 24 hour average or 76% of the available 24 hour increment of 5.0 ug/m3 ; and 22.1 ug/m3, 3 hour average, or 88% of the available 3 hour increment of 25 ug/m3. The maximum predicted PSD Class II nitrogen dioxide increment consumed is 2.24 ug/m3 annual average, or 9% of the available increment of 25 ug/m3. The maximum predicted PSD ClassI nitrogen dioxide increment consumed is 0.17 ug/m3, annual average, or 7% of the available increment of 2.5 ug/m3. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statues petitioner contends require reversal or modification of the Department's action or proposed action; and, (g) A statement of the relief sougt by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petiton must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The application 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
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Department of Environmental Protection
South District
2295 Victoria Ave., Ste. 364
Fort Myers, Florida 33901

Any person may send written comments on the proposed action to Mr. John Brown at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

CN 94-500
November 2, 1994

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

OCT 27 1994

RECEIVED
OCT 31 1994
Bureau of
Air Regulation

4APT-AEB

Mr. Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental
Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: United States Sugar Corporation, Clewiston, Hendry County, Florida (PSD-FL-208)

Dear Mr. Fancy:

This letter is in response to your request for review of an alternate opacity monitoring procedure for Clewiston Boiler No. 7 by your letter dated September 26, 1994. A request for Florida Department of Environmental Protection (FDEP) approval of an alternative opacity monitoring approach is included in a letter dated September 9, 1994, from Mr. Robert F. Van Voorhees of Bryan Cave to Ms. Teresa M. Heron of the FDEP. The alternative opacity monitoring approach proposed by U.S. Sugar for Boiler No. 7 consists of the installation of a video camera to be operated when Boiler No. 7 is firing No. 2 fuel oil. A memorandum dated January 19, 1993, from Mr. John B. Rasnic, Director, Stationary Source Compliance Division (SSCD) to the United States Environmental Protection Agency (EPA)-Region IV (copy enclosed), provides guidance regarding alternative opacity monitoring plan requirements for Subpart Db boilers firing primary and secondary fuels. Additional information from two Best Available Control Technology (BACT) packages received by EPA on February 28, 1994, and July 15, 1994, was also considered in the analysis of the proposed video monitoring plan.

An alternative opacity monitoring method may be proposed if the firing of No. 2 fuel oil in Clewiston Boiler No. 7 is considered an "infrequent operation". In order for fuel oil firing to be considered an "infrequent operation", there must be a federally enforceable permit condition limiting the annual capacity factor (ACF) for No. 2 fuel oil to 10 percent or less. If the above criteria for "infrequent operation" is met, an alternative opacity monitoring method may be considered. Although the earlier BACT information package referred to above includes a 10 percent fuel oil ACF restriction as part of the

File Copy

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

October 24, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Murray T. Brinson
Vice President, Sugar Processing
U.S. Sugar Corporation
P. O. Drawer 1207
Clewiston, Florida 33440

Dear Mr. Brinson:

RE: AC26-238006 and PSD-FL-208

Attached is one copy of the Technical Evaluation and Preliminary Determination, proposed Best Available Control Technology, and proposed permit for the construction/installation of the U.S. Sugar Corporation's new Boiler No. 7 to be located at the existing sugar mill on W.C. Owens Avenue and Clewiston Street, Clewiston, Hendry County, Florida.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. John Brown of the Bureau of Air Regulation.

Sincerely,

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

CHF/TH/bjb

Attachments

cc: David Knowles, SFD
Jewell Harper, EPA
John Bunyak, NPS
Robert Van Voorhees, Esquire
David Buff, KBN
Reading File
Teresa
Clair
} 10/24/94

Printed on recycled paper.

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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.

WEST PALM BEACH FL 33405

3. Article Addressed to:
Mr. Murray T. Brinson
Vice President, Sugar Processing
U.S. Sugar Corporation
P. O. Drawer 1207
Clewiston, Florida 33440

4a. Article Number
Z 751 859 997

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

7. Date of Delivery
10-26-94 RJ

5. Signature (Addressee)

6. Signature (Agent)
USSC Rayen Lawless

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

PS Form 3811, December 1991 ★U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

Z 751 859 997

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
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Sent to Mr. Murray T. Brinson	
Street and No. P. O. Drawer 1207	
P.O., State and ZIP Code Clewiston, Florida 33440	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 10/24/94 AC26-238006 & PSD-FL-208	

PS Form 3800, March 1993

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DEP File No. AC26-238006
PSD-FL-208
Hendry County

Mr. Murray T. Brinson
Vice President
U. S. Sugar Corporation
P. O. Drawer 1207
Clewiston, Florida 33440
______________________________/

INTENT TO ISSUE

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

The applicant, U.S. Sugar Corporation, applied on September 17, 1993, to the Department of Environmental Protection for a permit to construct one 738 MMBtu/hr bagasse/fuel oil fired boiler (Boiler No. 7) located at W.C. Owens Avenue and Clewiston Street, Clewiston, Hendry County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, F.S., and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "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. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within seven days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will issue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

for Johnie Brown Jr
C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 10/24/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell 10/24/94
Clerk Date

Copies furnished to:

David Knowles, SFD
Jewell Harper, EPA
John Bunyak, NPS
Robert VanVoorhees, Esquire
David Buff, KBN

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF INTENT TO ISSUE PERMIT

AC26-238006

PSD-FL-208

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit to the U.S. Sugar Corporation, P. O. Box 1207, Clewiston, Florida 33440, to install a 738 MMBtu/hr bagasse/fuel oil fired boiler. The No. 2 fuel oil (maximum 0.05% sulfur content and 0.015% nitrogen content, by weight) fired in the new Boiler No. 7 will be limited to 10% of the total potential heat input to the boiler in any calendar year. The proposed facility will be located at the U.S. Sugar Corporation's sugar mill on W.C. Owens Avenue and Clewiston Street, Clewiston, Hendry County, Florida. The increased emissions from the boiler will be partially offset by the reduction in emissions from the existing boilers (No. 5 and No. 6). Boilers No. 5 and No. 6 will be retained on standby when the new Boiler No. 7 is in operation. The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations for the following pollutants: sulfur dioxide, nitrogen oxides, volatile organic compounds, sulfuric acid mist and beryllium. A determination of Best Available Control Technology (BACT) was required for these pollutants. The maximum predicted PSD Class II sulfur dioxide increments consumed by all sources, including this project, after this project is constructed are the following: 3.96 ug/m^3, annual average, or 20% of the available annual increment of 20 ug/m^3; 36.7 ug/m^3, 24-hour average, or 40% of the available 24-hour increment of 91 ug/m^3; and 203 ug/m^3, 3-hour average, or 40% of the available 3-hour increment of 512 ug/m^3. The maximum predicted PSD Class I sulfur dioxide increments consumed are the following: 0.39 ug/m^3, annual average or 20% of the available annual increment of 2.0 ug/m^3; 3.82 ug/m^3, 24-hour average or 76% of the available 24-hour increment of 5.0 ug/m^3; and 22.1 ug/m^3, 3-hour average, or 88% of the available 3-hour increment of 25 ug/m^3. The maximum predicted PSD Class II nitrogen dioxide increment consumed is 2.24 ug/m^3, annual average, or 9% of the available increment of 25 ug/m^3. The maximum predicted PSD Class I nitrogen dioxide increment consumed is 0.17 ug/m^3, annual average, or 7% of the available increment of 2.5 ug/m^3. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and, (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The application 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
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Department of Environmental Protection
South District
2295 Victoria Ave., Ste. 364
Fort Myers, Florida 33901

Any person may send written comments on the proposed action to Mr. John Brown at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

U.S. Sugar Corporation
Clewiston, Hendry County, Florida

738 MMBtu/hr Bagasse/Fuel Oil Fired Boiler

File No.: AC26-238006
PSD-FL-208

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

October 24, 1994

1. SYNOPSIS OF APPLICATION

I.1 Applicant Name and Address

U.S. Sugar Corporation, Clewiston
P. O. Drawer 1207
Clewiston, Florida 33440

I.2 Reviewing and Process Schedule

Date of Receipt of Application: September 17, 1993

Application Completeness Date: July 12, 1994

Waiver of the 90-day clock: October 31, 1994

II. FACILITY INFORMATION

II.1 Facility Location

The U.S. Sugar Corporation is located at W.C. Owens Avenue and Clewiston Street in Clewiston, Florida. The UTM coordinates are 506.1 km E and 2956.9 km N.

II.2 Standard Industrial Classification Code

This facility is classified as follows:

Major Group	20
Group No.	206
Industry No.	2061

II.3 Facility Category

The U.S. Sugar Corporation, Clewiston mill, in Clewiston, is classified as a major emitting facility for particulate matter (PM), particulate matter greater than 10 microns (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). The proposed project (Boiler No. 7) will increase emissions of all these pollutants except PM and CO above the PSD significant emission levels.

III. PROJECT DESCRIPTION

The U.S. Sugar Corporation proposes to install a new bagasse and fuel oil fired boiler at the Clewiston mill. Due to contemporaneous

Table 2. Revised PSD Source Applicability for U.S. Sugar Clewiston Boiler No.7

Regulated Pollutant	Contemporaneous Decreases (TPY) Boiler 5	Boiler 6	Total	Increase Due to Boiler No.7 (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	52.8	59.3	112.1	129.3[a]	17.2	25	No
Particulate(PM10)	47.6	53.3	100.9	113.1[b]	12.2	15	No
Sulfur dioxide	11.1	12.3	23.5	549.5	526.05	40	Yes
Nitrogen oxides	26.4	29.6	56.1	808.1[c]	752.05	40	Yes
Carbon monoxide	1,180.1	1,323.7	2,503.8	2,262.7[d]	-241.1	100	No
Volatile Org.Compds.	44.0	49.4	93.4	685.3	591.85	40	Yes
Lead	-	-	-	0.018	0.018	0.6	No
Mercury	-	-	-	0.0021	0.0021	0.1	No
Beryllium	-	-	-	0.0027	0.0027	0.0004	Yes
Fluorides	-	-	-	0.0041	0.0041	3	No
Sulfuric acid mist [b]	1.1	1.2	2.35	55.0[e]	52.6	7	Yes
Total reduced sulfur	-	-	-	-	-	10	No
Asbestos	-	-	-	-	-	0.007	No
Vinyl Chloride	-	-	-	-	-	0	No

[a]. Based on PM emission limit of 0.04 lb/MMBtu.
[b]. Based on PM10 emission limit of 0.035lb/MMBtu.
[c]. Based on NOx emission limit of 0.25lb/MMBtu.
[d]. Based on CO emission rate of 0.70 lb/MMBtu.

emission commitments, the U.S. Sugar Corporation is committed to placing two existing bagasse fired boilers (No. 5 and No. 6) on a standby status while the new Boiler No. 7 is in operation. The increased emissions from the proposed new boiler would be offset by the reduction in emissions from the existing boilers. In addition, U.S. Sugar Corporation is proposing to raise the stacks of the existing Boilers Nos. 1, 2 and 3 to height of the Boiler No. 4 stack (150 feet above grade).

The proposed boiler will combust primarily bagasse to generate up to 350,000 lbs/hr of steam for the mill. The total heat release of Boiler No. 7 at this maximum steam production rate will be 738 MMBtu/hr. The No. 2 fuel oil fired in Boiler No. 7 will be limited to 10% of the maximum potential heat input to the boiler in any calendar year. The No. 2 fuel oil for Boiler No. 7 will be limited to maximum contents of 0.05% sulfur and 0.015% nitrogen, by weight.

III.1 Background Information

The U.S. Sugar Corporation's sugar cane processing mill in Clewiston consists of six existing bagasse boilers. Bagasse is a fuel of varying composition, consistency, and heating value. These characteristics depend on the climate, type of soil upon which the cane is grown, variety of cane, harvesting method, amount of cane, washing, and the efficiency of the milling process. In general, bagasse has a heating value between 3,000 and 4,000 Btu/lb on a wet, as-fired basis. Most bagasse has a moisture content between 50 and 55%, by weight. High-pressure process steam for the mill is provided by burning bagasse in six boilers and occasionally No. 2 fuel oil in four boilers. This steam is used to power the grinding mill turbines, electrical turbogenerators, and other equipment drives. The exhaust steam is sent to the boiling house for use in juice heaters, evaporators, vacuum pans, and other processing equipment. About 3.4 lbs of steam is needed to produce 1 lb of raw sugar.

IV. RULE APPLICABILITY

The proposed project, construction of a 738 MMBtu/hr bagasse boiler at an existing sugar mill (SIC 2061) in Hendry County, is subject to the preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-210, 62-212, 62-272, 62-275, 62-296, and 62-297, Florida Administrative Code (F.A.C.).

The proposed source will be located in an area designated attainment for all criteria pollutants (Rule 62-275.400, F.A.C.).

The facility is a major source for PM, SO_2, NO_x, CO, and VOC. The potential emissions of each of these air pollutants exceed 100 TPY (Rule 62-212.200, F.A.C.). The proposed facility is subject to the Prevention of Significant Deterioration (PSD) regulations (62-212.400, F.A.C.) because the requested increase in SO_2, NO_x, VOC, sulfuric acid mist (H_2SO_4), and beryllium (Be) exceed the significant emission rates (Rule Table 212.400-2, F.A.C.). PM and CO emissions are below the significant emission rates due to contemporaneous net emission reductions. The allowable emissions of the pollutants with significant emissions rate increases will be established by a Best Available Control Technology (BACT) determination (Rule 62-212.410, F.A.C.). The proposed source is also subject to the applicable requirements of the federal new source performance standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db), adopted by reference pursuant to Rule 62-296.800, F.A.C.

V. SOURCE IMPACT ANALYSIS

V.1 Control Technology Review

The proposed 738 MMBtu/hr boiler will be capable of burning bagasse and will use an electrostatic precipitator (ESP) for PM, PM_{10}, and Be control; overfire air and low nitrogen fuel oil for NO_x control; and, good combustion practices for VOC and CO control. During Boiler No. 7 operation, existing bagasse and fuel oil fired Boilers No. 5 and No. 6 will be placed on standby status at the U.S. Sugar Corporation's existing sugar mill.

The primary fuel will be bagasse. The No. 2 fuel oil will be used as an auxiliary or supplementary fuel. Heat input from the No. 2 fuel oil will be restricted to 10 percent of the maximum potential heat input to the boiler in any calendar year. PM and PM_{10} emissions from the new boiler will be controlled by an ESP that has a design efficiency in excess of 98 percent. The ESP will be capable of meeting the PM standard of 0.04 lb/MMBtu heat input and the PM_{10} standard of 0.035 lb/MMBtu heat input while firing bagasse; and, 0.04 lb/MMBtu for both PM and PM_{10} while firing fuel oil. The NSPS visible emissions standard is 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Compliance with the PM standard and the PM_{10} standard will be determined by periodic stack tests and the visible emissions will be continuously monitored. The proposed boiler is not subject to the PSD new source review regulations for PM or PM_{10}.

SO_2 and H_2SO_4 acid mist emissions will be controlled by the use of low sulfur fuel oil. Bagasse, the primary fuel, averages about 0.1 percent sulfur content, by weight, on a dry basis. The No. 2 fuel oil shall have a maximum sulfur content of 0.05 percent, by weight. Compliance with the SO_2 emission standards will be demonstrated by fuel analysis and stack testing. The facility is subject to PSD and BACT for SO_2 emissions and H_2SO_4 mist, because the increase in annual emissions for each one of these pollutants exceeds the associated significant emission rate.

CO and VOC emissions will be controlled through boiler design and good combustion practices. The requested emissions are shown in Table 2. The project is expected to result in a significant emission increase of VOC. Thus, the project is also subject to PSD for this pollutant. Compliance with the emission standards will be determined by stack tests. Good operation practices, based on the guidance in the document titled "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls", is acceptable as BACT to control VOC emissions.

Table 1 lists the allowable emissions from the new 738 MMBtu/hr boiler.

Table 2 summarizes the emissions of air pollutants subject to PSD review.

V.2 Air Quality Report

a. Introduction

The proposed project will emit five pollutants in PSD significant amounts. These pollutants are SO_2, NO_x, and VOC, along with the non-criteria pollutants, Be and H_2SO_4 mist.

The air quality impact analyses required by the PSD regulations for these pollutants include:

* An analysis of existing air quality;
* A PSD increment analysis (SO_2 and NO_2);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts; and,
* A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The PSD increment and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department of Environmental Protection (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 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 modeling methodology and required analyses follows.

b. Analysis of Existing Air Quality and Determination of Background Concentrations

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimus concentration. Pollutants which do not have a specified de minimus level may also be exempt from preconstruction monitoring requirements. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Even if preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants may be necessary for use in the AAQS analysis for each pollutant. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from previously 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.

Table 3 shows that NO_2 and Be impacts from the project were predicted to be less than the de minimus levels. There is no monitoring de minimus level for H_2SO_4 mist. Therefore, preconstruction ambient air quality monitoring is not required for these three pollutants. The net emissions increase of VOC is greater than 100 tons per year; therefore, preconstruction ambient air monitoring for ozone is required. Since the Florida Sugar Cane League (FSCL) has for several years operated a continuous ambient SO_2 monitor which represents existing air quality in the sugar cane growing area, no SO_2 de minimus analysis was done. However, had SO_2 impacts been specifically determined for comparison with the de minimus monitoring level, the level would have been exceeded. Because of this, the applicant used the data from its SO_2 monitor to satisfy preconstruction monitoring requirements. This monitor is located at the Florida Celery Exchange in Belle Glade, which is about 25 km east of the U.S. Sugar Corporation-Clewiston sugar mill.

Data from the FSCL SO_2 monitor were also used for background purposes in the SO_2 modeling analysis. The second highest 3-hour and 24-hour and highest annual average SO_2 concentrations measured at the Belle Glade monitor during the period of 1989-1991 were used. The background SO_2 concentrations for the appropriate averaging times are shown in the AAQS table, Table 6.

VOC is the regulated pollutant for ozone. In lieu of requiring preconstruction monitoring of ozone in the vicinity of the plant, the Department accepted the use of existing data from the Delray Beach ozone monitor in West Palm Beach. This data was collected during 1991-1993. The background concentration determined from this monitor is 91 parts per billion, 1 hour average, and it conservatively represents existing air quality in the area of the Clewiston plant.

In addition, a background concentration for NO_2 was determined. The background NO_2 concentration was based on data collected during 1987-1992 from the state and local air monitoring system (SLAMS) monitor located in West Palm Beach, and it is shown in the AAQS table, Table 6.

c. Modeling Methodology

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used to evaluate the pollutant emissions from the proposed emissions unit and its facility 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 ISCST2 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.

Initially, for the significant impact analysis, concentrations were predicted at 900 receptors located in a radial grid centered on the proposed boiler. Receptors were located in 25 concentric rings at distances ranging from 0.35 to 100 km away from the proposed boiler. Each ring contained 36 receptors spaced at 10-degree intervals. For the AAQS and PSD Class II analyses, receptor grids were based on the size of the significant impact area for each pollutant. The radius of significant impact ranged from 100 km for SO_2 to only 15 km for NO_2. The receptor grids within 15 km were the same for each pollutant and included 36 receptors per ring (again, spaced at 10-degree intervals) located at the following distances from the proposed boiler: 0.3, 0.4, 0.5, 0.6, 0.7, 0.8, 0.9, 1.0, 2.0, 3.0, 4.0, 5.0, 6.0, 7.0, 8.0, 10.0, and 15.0 km. In addition, impact analyses for pollutants with significant impacts beyond 15 km included the following distances as necessary: 20, 25, 30, 40, 50, 65, 80, and 100 km.

The Everglades National Park is a PSD Class I area that is located 102 km from the Clewiston plant site at its closest point. In the PSD Class I analysis, Everglades National Park is represented by 51 discrete receptors, including 47 receptors covering the eastern and northern boundaries of the park from the Florida Keys to the Gulf of Mexico and 4 receptors inside the northeast corner of the Park.

Meteorological data used in the ISCST2 model to determine air quality impacts 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. The 5-year period of meteorological data was from 1985 through 1989. The NWS station at West Palm Beach, located approximately 100 km east of the Clewiston site, 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 plant site. The surface observations included wind direction, wind speed, temperature, cloud cover and cloud ceiling.

Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the significant impact area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to the significant impact levels.

d. Significant Impact Analysis

As stated in the section above, the maximum air quality impacts due to SO_2 and NO_x emissions from the proposed project are greater than the significant impact levels. The radii of significant impact for SO_2 and NO_2 are 100 km and 15 km, respectively.

e. PSD Increment Analysis

1. Class II Area

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. The results, summarized in Table 4, show that the maximum SO_2 and NO_2 PSD increment consumption will not exceed the allowable Class II PSD increments.

2. Class I Area

A proposed source subject to PSD review must conduct a dispersion modeling analysis of its impacts on any PSD Class I area located near the source. The closest receptor point in the Class I Everglades National Park is approximately 102 km from the Clewiston plant site. The modeling results are summarized in Table 5. Based on these results, the proposed facility along with all other increment consuming sources in the area will meet the allowable SO_2 and NO_2 PSD increments in the Class I area.

f. AAQS Analysis

For the pollutants subject to an AAQS review, the total impact on ambient air 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 for SO_2 and NO_2 are summarized in Table 6. The proposed project is also subject to an AAQS analysis for ozone since the projected increase in VOC emissions is greater than 100 TPY. However, there are no currently available air dispersion models for use in modeling VOC point sources in relation to ozone concentrations. For this reason and also since the proposed project is located in an ozone attainment area, VOC emissions will be regulated through the BACT requirements; and, PSD review for these emissions will be based primarily on the BACT determination. Emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

g. Air Toxics Analysis

The maximum impacts of regulated and non-regulated toxic air pollutants that will be emitted by the U.S. Sugar Corporation-Clewiston mill project are presented in Table 5. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the Department's draft Acceptable Ambient Concentrations (AAC). Except for H_2SO_4 mist, the table shows that all toxic pollutant impacts will be below their respective reference concentrations. H_2SO_4 mist is also a non-criteria pollutant, which means that neither an AAQS nor a PSD increment has been defined for this pollutant. The boiler is subject to stringent "top down" BACT for this pollutant because it is a regulated pollutant. H_2SO_4 mist emissions will be controlled by the use of low sulfur fuel oil.

V.3 <u>Additional Impacts Analysis</u>

a. Impacts on Soils, Vegetation, and Wildlife

The maximum ground-level concentrations predicted to occur for SO_2 and NO_x as a result of the proposed project, including background concentrations and 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.

b. Impact on Visibility

Visual Impact Screening and Analysis (VISCREEN), the EPA-approved Level I visibility computer model, was used to estimate the impact of the proposed project's stack emissions on visibility in the Everglades National Park. The results indicate that the maximum visibility impacts do not exceed the screening criteria inside or outside the Everglades National Park Class I area. As a result, there is no significant impact on visibility predicted for the Class I area.

c. Growth-Related Air Quality Impacts

There will be a small number of temporary construction workers during construction. However, there will be no significant impacts on air quality caused by associated population growth.

d. GEP Stack Height Determination

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 Boiling House is the most significant structure associated with Boiler No. 7. This building has a height of 27.4 m and is 66.1 by 69.8 m wide. From the above formula, the GEP stack height is 27.4 + (1.5 x 27.4) = 68.6 m (225 ft). The stack for Boiler No. 7 will be 68.6 m high. This stack will not exceed the GEP stack height.

VI. **CONCLUSION**

Based on the information provided by the U.S. Sugar Corporation, the Department has reasonable assurance that the proposed construction/installation of the 738 MMBtu/hr boiler, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any AAQS, PSD increment, or any other technical provision of Chapter 62-212 of the Florida Administrative Code.

John Browning
10-24-94

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

PERMITTEE:
U.S. Sugar Corporation
P. O. Box 1207
Clewiston, Florida 33440

Permit Number: AC26-238006
PSD-FL-208
Expiration Date: September 1, 1996
County: Hendry
Latitude/Longitude: 26°44'05"N
80°56'20"W
Project: Boiler No. 7

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-210 through 62-297 and 62-4, Florida Administrative Code (F.A.C.); and, 40 CFR 52.21. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and specifically described as follows:

Construction of a 738 MMBtu/hr heat input (350,000 lbs/hr steam) boiler designed to burn bagasse and No. 2 fuel oil. The consumption of fuel oil shall not exceed 10% of the maximum potential heat input to the new boiler in any calendar year. Boiler No. 7 will be constructed/installed at the U.S. Sugar Corporation's existing sugar mill that is located near the intersection of W. C. Owens Avenue and Clewiston Street in Clewiston, Hendry County, Florida. The UTM coordinates of this site are 17-506.1 km East and 2956.9 km North.

The emissions unit shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Application received September 17, 1993.
2. Department's letter dated October 15, 1993.
3. U.S. Sugar Corporation's letter dated December 22, 1993.
4. U.S. Sugar Corporation's letter dated February 22, 1994.
5. Department's letter dated February 28, 1994.
6. Department's letter dated March 18, 1994.
7. U.S. Sugar Corporation's letter dated May 10, 1994.
8. U.S. Sugar Corporation's letter dated June 7, 1994.
9. U.S. Sugar Corporation's letter dated June 29, 1994.
10. U.S. Sugar Corporation's letter dated July 13, 1994.
11. U.S. Sugar Corporation's letter dated July 28, 1994.

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. a description of and cause of non-compliance; and,

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

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

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

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

GENERAL CONDITIONS:

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

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

13. This permit also constitutes:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration (PSD)
(x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and,
- the results of such analyses.

GENERAL CONDITIONS:

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.

SPECIFIC CONDITIONS:

EMISSION LIMITATIONS

1. Based on a maximum heat input to the boiler of 738 MMBtu/hr for bagasse and 250 MMBtu/hr for fuel oil, stack emissions shall not exceed the following limits:

ALLOWABLE EMISSIONS

Pollutant	Bagasse			No. 2 Fuel Oil		
	lb/MMBtu	lbs/hr	tons/yr	lb/MMBtu	lbs/hr	tons/yr
Particulate Matter (PM)	0.04	30	129	0.04	10	12.88
PM_{10}	0.035	26	113	0.04	10	12.88
Sulfur Dioxide	0.17	125	550	0.05	12.5	16.10
Nitrogen Oxides	0.25	185	809	0.2	50.0	64.40
Carbon Monoxide	0.70	516	2,262	0.066	16.5	21.25
Volatile Organic Compounds	0.212	157	685	0.004	1.0	1.29
Sulfuric Acid Mist	0.017	13	55	0.005	1.25	1.60

CONSTRUCTION AND OPERATIONAL REQUIREMENTS

2. Construction of Boiler No. 7 shall conform to the plans described in the application.

3. The boiler shall be of the spreader-stroker vibrating-grate type.

4. The boiler's stack shall have a minimum height of 225 feet. After Boiler No. 7 becomes operational, Boilers Nos. 1, 2, and 3 stacks shall have a minimum height of 150 feet. The stack sampling facilities for each stack shall comply with Rule 62-297.345, F.A.C.

5. The boiler shall be equipped with instruments to measure fuel oil flowrate, steam production, steam pressure, and steam temperature.

SPECIFIC CONDITIONS:

6. The boiler shall be equipped with an electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

The permittee shall submit to the Department copies of technical data pertaining to the selected ESP and to the boiler design within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency, emission rate and major design parameters.

Nitrogen oxides emissions will be controlled by overfire air and good combustion practices; and, will be minimized using low-nitrogen fuel oil (max. 0.015% N content, by weight). Carbon monoxide and volatile organic emissions will be controlled by good combustion practices. Sulfur dioxide and sulfuric acid mist emissions, when firing fuel oil, will be controlled by using very low-sulfur No. 2 fuel oil (max. 0.05% S content, by weight).

7. Boiler No. 7 shall be operated in accordance with the capabilities and specifications described in the application. Steam production, heat input, and bagasse consumption shall not exceed the following:

Steam Pressure psig	Steam Temp. F°	Averaging Time	Steam Production lbs/hr	Heat Input MMBtu/hr	Bagasse Feedrate lbs/hr-wet
600	750	1-hr max. Max. 24-hr avg.	385,000 350,000	812 738	203,060 184,600

8. Heat input from No. 2 fuel oil (0.05% S content, by weight) shall not exceed 250 MMBtu/hr (which is approximately equivalent to 1,785 gallons per hour of oil and 175,000 pounds per hour of steam). The boiler shall be operated so that not more than two burners with two oil guns each (total of four oil guns) can be used with a total maximum capacity not to exceed the permitted fuel oil input rate.

9. During any calendar year, the maximum quantity of No. 2 fuel oil (maximum 0.05% S content, by weight) burned in Boiler No. 7 shall not exceed 4,600,000 gallons. The consumption of fuel oil shall not exceed 10% of the maximum potential heat input to the boiler in any calendar year.

10. All stationary fuel-oil burning equipment at the plant shall be equipped with integrating fuel oil flow meters or continuous

SPECIFIC CONDITIONS:

recorders to measure the amount of fuel oil consumed by the equipment. Fuel oil meter readings on all fuel oil consuming equipment shall be read and logged at least once every three hours, unless fuel oil consumption for the equipment is recorded continuously, and these records shall be kept for at least five years for Department inspection. Each meter shall be calibrated annually by a method approved by the Department.

11. The fuel oil system for Boiler No. 7 shall be designed, constructed, and operated so that it cannot exceed the fuel feed rate equivalent to or greater than 250 MMBtu/hr heat input (high heating value of the fuel oil, 1-hour average). Not more than 1/3 of the potential electric output capacity and not more than 25 MW electricity output shall be supplied to any utility power distribution system for sale. The permittee shall maintain records of the hourly fuel oil feed rate to the boiler, the percentage of electrical power output distributed to any utility power distribution system, and the amount of electrical power (MW) distributed to any utility power distribution system (40 CFR 60, Subpart Da).

12. Boilers No. 5 and No. 6 may be retained as standby boilers at the Clewiston Mill. Boilers No. 5 and No. 6 may be operated during initial start-up, debugging, and testing of Boiler No. 7. After Boiler No. 7 becomes operational, Boilers No. 5 and No. 6 may be operated only when one or more boilers of equal or greater permitted heat input at the Clewiston Mill are shut down. During operation, Boilers No. 5 and No. 6 must comply with all requirements in their current operating permits. The operation permits for Boilers No. 5 and No. 6 shall be amended to reflect this condition.

13. Prior to operation of the emissions unit, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor the emissions control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

COMPLIANCE REQUIREMENTS

14. Performance Stack Tests. Within 60 calendar days after achieving the maximum capacity at which this unit will be operated, but no later than 180 days after initial (I) startup and annually (A) thereafter, the permittee shall conduct performance tests for: sulfur dioxide (I and upon permit renewal), sulfuric acid mist (I), particulate matter (I,A), nitrogen oxides (I,A), volatile organic compounds (I,A), and carbon monoxide (I,A) while burning bagasse. The performance tests shall be conducted in accordance with the provisions of 40 CFR 60.45b and 60.46b. Testing of emissions shall be conducted with the emission unit operating at permitted

SPECIFIC CONDITIONS:

capacity. Permitted capacity is defined as 90-100% of the maximum operating rate allowed by the permit. If it is impracticable to test at permitted capacity, then Boiler No. 7 may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once Boiler No. 7 is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for the purposes of additional compliance testing to regain the permitted capacity in the permit. Results of the tests shall be submitted to the Department's South Florida District office within 45 days after testing. The Department's South Florida District office shall be notified 30 days prior to any compliance test to allow witnessing.

The EPA Reference Methods shall be performed in accordance with 40 CFR Part 60 (Standards of Performance for New Stationary Sources), Appendix A, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), Appendix B. No other test method may be used until authorization has been obtained in writing from the Department. An alternate sampling procedure can be acquired in accordance with Chapter 62-297, F.A.C. A test protocol shall be submitted for approval to the Department's Bureau of Air Regulation at least 90 days prior to testing.

15. Particulate matter (PM/PM_{10}) emissions from Boiler No. 7 shall not exceed 0.04 lb/million Btu heat input for bagasse fuel (PM) and 0.035 lb/million BTU heat input for bagasse fuel (PM_{10}) or 0.04 lb/million Btu heat input for No. 2 fuel oil (PM/PM_{10}). In the event that both fuels are burned concurrently, the allowable particulate matter emissions shall be prorated from the allowable standards for each fuel by their respective heat inputs. Compliance with the PM and PM_{10} standards shall be determined by EPA Reference Methods 1, 2, 3 or 3A, 4, 5 or 17 and 201 or 201A, respectively, in accordance with 40 CFR 60, Appendix A. The compliance test results shall be calculated by assuming the thermal efficiency of Boiler No. 7 to be 55%. For information purposes only, the particulate matter emission rates shall also be calculated by utilizing the short-form ASME boiler-efficiency test results (once every five years: required for the initial operation permit and to be on the same schedule as the operation permit).

16. Unconfined Particulate Matter emissions during land clearing and site preparation shall be minimized using wetting operations or other soil treatment techniques appropriate for controlling unconfined particulate matter emissions including, but not limited to, grass seedings and mulching of disturbed areas. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations.

SPECIFIC CONDITIONS:

17. Visible emissions from Boiler No. 7 shall not exceed 20% opacity, except that 27% opacity is allowed for 6-minutes during any 1-hour period. Compliance with the standard shall be determined using EPA Reference Method 9 pursuant to Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. The particulate matter emissions and visible emissions tests shall be determined concurrently. Under circumstances when this is not feasible, the company shall obtain approval from the Department's South Florida District to conduct the tests at separate times.

In such circumstances, the tests shall be conducted as close to each other as is feasible. In accordance with 40 CFR 60.486 the permittee shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions. The monitoring device shall meet the applicable requirements under Chapter 62-297, F.A.C., and 40 CFR 60, Appendix B.

18. Visible emissions from the bagasse handling systems shall not exceed 10% opacity over any 6-minute period as measured by EPA Reference Method 9. Reasonable precautions shall be used to minimize fugitive emissions when reclaiming dry bagasse for the boiler. The permittee shall maintain a meteorological instrument to record the wind speed at the plant, which shall be located at its Research Center located about one mile "south" of the Clewiston mill.

19. No. 2 fuel oil burned in this boiler shall contain no more than 0.05% sulfur content, by weight. Compliance with this condition shall be determined from certified analyses of the oil by ASTM Method D-129, D-1552, D-2622 or D-4294, by the fuel supplier or the permittee. Records of the quantity and analysis of fuel oil consumed in Boiler No. 7 and invoices for the fuel oil purchases shall be kept for a minimum of five years for regulatory agency inspection.

20. Sulfur dioxide emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.17 lb/million Btu heat input, as determined by EPA Reference Method 6 and in accordance with 40 CFR 60, Appendix A. Sulfuric acid mist emissions from Boiler No. 7, while it is burning 100% bagasse fuel, shall not exceed 0.017 lb/Million Btu heat input as determined by EPA Reference Method 8 and in accordance with 40 CFR 60, Appendix A.

21. Nitrogen oxides emissions, expressed as NO_2, shall not exceed 185 lbs/hr as determined by EPA Reference Method 7 and in accordance with 40 CFR 60, Appendix A. The fuel oil shall contain no more than 0.015% nitrogen content, by weight, as determined using ASTM D4629.

SPECIFIC CONDITIONS:

2. Carbon monoxide and volatile organic compounds emissions shall be maintained at the lowest possible level through the implementation of an Operation and Maintenance plan that has been approved by the Department. Emissions of carbon monoxide shall not exceed 0.70 lb/million Btu as determined by EPA Method 10 and in accordance with 40 CFR 60, Appendix A. Emissions of nonmethane volatile organic compounds shall not exceed 1.7 lb/ton of wet bagasse or 0.21 lb/MMBtu as determined by EPA Method 25 or 25A in conjunction with EPA Method 18 and in accordance with 40 CFR 60, Appendix A.

23. Thermal efficiency. A test shall be conducted on Boiler No. 7 to determine its actual thermal efficiency in accordance with the ASME short-form procedure each time the operating permit for this boiler is renewed. The test shall be done while the tubes are clean and within 14 days of the compliance test, unless an alternative schedule is approved by the Department. A current report on the thermal efficiency tests must be included with the application to operate this boiler.

REPORTING REQUIREMENTS

24. Fuel usage, fuel analysis data, and sulfur dioxide emissions calculations for fuel oil combustion shall be reported to the Department's South District Office on a quarterly basis commencing with the start of full-time operation in accordance with 40 CFR 60, Sections 60.7 and 60.49b.

RULE REQUIREMENTS

25. This emissions unit shall comply with all applicable provisions of Chapter 403, F.S.; Chapter 62-4 and Chapters 62-210 through 297, F.A.C.; 40 CFR 60; and, applicable requirements of 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

26. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62.210.300(1), F.A.C.).

27. This source shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS) Subpart Db; Rule 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation Problems.

SPECIFIC CONDITIONS:

28. Pursuant to Rule 62-210.370(2), F.A.C., Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual reports shall be sent to the Department's South Florida District office.

29. The permittee shall install permanent stack sampling facilities in accordance with Rule 62-297.345, F.A.C.

30. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

31. An application for an operation permit must be submitted to the Department's South District office at least 90 days prior to the expiration date of this construction permit or within 45 days after completion of compliance testing, whichever occurs first. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.220, and 17-4.055, F.A.C.).

Issued this ______ day
of ______________, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

____
Virginia B. Wetherell, Secretary
Department of Environmental
Protection

Best Available Control Technology (BACT) Determination
U. S. Sugar Corporation
Hendry County
Boiler No. 7
PSD-FL-208

The applicant proposes to install a new bagasse and fuel oil fired boiler at its Clewiston sugar mill. This new boiler, No. 7, will provide steam to the sugar cane processing operations. Two existing bagasse boilers (Nos. 5 and 6) will be retained on standby. In addition, U.S. Sugar Corporation is proposing to raise the stacks of the existing Boilers Nos. 1, 2 and 3 to 150 feet above grade.

The boiler will combust primarily bagasse to generate an average of 350,000 lbs/hr of steam for the mill. The total heat input of Boiler No. 7 at this steam production rate will be 738 MMBtu/hr. Steam production due to fuel oil firing will be approximately 175,000 lbs/hr. Heat input from the No. 2 fuel oil (max. 0.05% sulfur content, by weight) shall not exceed 250 MMBtu/hr. The consumption of fuel oil shall not exceed 10% of the total potential heat input to the boiler in any calendar year. Table I lists the pollutants potentially subject to PSD analysis. Table II shows the PSD source applicability. The applicant has proposed the maximum annual tonnage of regulated air pollutants emitted from this boiler based on operation for 8760 hours per year and burning bagasse.

TABLE 1

Boiler No. 7

Pollutant	Potential Emissions (Tons/Yr)		PSD Significant Emission Rate (Tons/Yr)
	Oil	Bagasse	
NO_x	64.40	809	40
SO_2	16.10	550	40
PM	12.88	129	25
PM_{10}	12.88	113	15
CO	21.25	2,262	100
VOC	1.29	685	40
H_2SO_4	1.60	55	7
Be	0.003		0.0004
Hg	0.002		0.1
Pb	0.02		0.6

Rule 62-2.410, Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Table 2. Revised PSD Source Applicability for U.S. Sugar Clewiston Boiler No.7

Regulated Pollutant	Contemporaneous Decreases (TPY) Boiler 5	Boiler 6	Total	Increase Due to Boiler No.7 (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	52.8	59.3	112.1	129.3[a]	17.2	25	No
Particulate(PM10)	47.6	53.3	100.9	113.1[b]	12.2	15	No
Sulfur dioxide	11.1	12.3	23.5	549.5	526.05	40	Yes
Nitrogen oxides	26.4	29.6	56.1	808.1[c]	752.05	40	Yes
Carbon monoxide	1,180.1	1,323.7	2,503.8	2,262.7[d]	-241.1	100	No
Volatile Org.Compds.	44.0	49.4	93.4	685.3	591.85	40	Yes
Lead	-	-	-	0.018	0.018	0.6	No
Mercury	-	-	-	0.0021	0.0021	0.1	No
Beryllium	-	-	-	0.0027	0.0027	0.0004	Yes
Fluorides	-	-	-	0.0041	0.0041	3	No
Sulfuric acid mist [b]	1.1	1.2	2.35	55.0[e]	52.6	7	Yes
Total reduced sulfur	-	-	-	-	-	10	No
Asbestos	-	-	-	-	-	0.007	No
Vinyl Chloride	-	-	-	-	-	0	No

[a]. Based on PM emission limit of 0.04 lb/MMBtu.
[b]. Based on PM10 emission limit of 0.035lb/MMBtu.
[c]. Based on NOx emission limit of 0.25lb/MMBtu.
[d]. Based on CO emission rate of 0.70 lb/MMBtu.

Date of Receipt of a BACT Application:

September 17, 1993

Date Application Complete:

July 12, 1994

Waiver of the 90-day Clock:

October 31, 1994

BACT Determination Requested by the Applicant:

Pollutant	Determination
NO_X	Low-NO_X burners/low nitrogen fuel oil Bagasse: 0.25 lb/MMBtu Fuel oil: 0.2 lb/MMBtu
VOC	Good combustion practices
SO_2	Firing very low-sulfur No. 2 fuel oil (maximum of 0.05% sulfur content, by weight), not to exceed 10% of the total potential annual heat input. Bagasse: 0.17 lb SO_2/MMBtu Oil: 0.05 lb SO_2/MMBtu
H_2SO_4 mist	Firing very low-sulfur No. 2 fuel oil (maximum of 0.05% sulfur content, by weight)
Be	Electrostatic Precipitator

BACT DETERMINATION PROCEDURE

In accordance with Rule 62-212.410, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted above the significant levels which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, 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).

(b) All scientific, engineering, and technical material and other information available to the Department

(c) The emission limiting standards or BACT determination of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically infeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. The air pollutant emissions from this boiler can be grouped into categories based upon what control equipment and techniques are available to control emissions from these types of emission units. Using this approach, the emissions can be classified as follows:

- Combustion Products (PM, PM_{10}, and Heavy Metals). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (CO, VOC, and Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.

- Acid Gases (SO_x, NO_x, HCl, Fl, and H_2SO_4). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT ANALYSIS

Combustion Products (Be):

U. S. Sugar Corporation's projected contemporaneous emission rate changes for PM and PM_{10} are below the significant emission rates since Boilers No. 5 and No. 6 will be placed on standby status while Boiler No. 7 is in operation. Beryllium emissions are subject to PSD review because they are above the significant levels as given in Rule 62-2.400, Table 212.400-2, F.A.C. In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium from boilers. BACT for these heavy metals is typically represented by the level of particulate control and, in this case, through the use of an electroststic precipitator. As this is the case, the emission factor of 0.04 lb/MMBtu for PM is judged to represent BACT for beryllium.

Products of Incomplete Combustion (VOC):

The emissions of volatile organic compounds (VOC) are above the significant level and therefore require a BACT analysis. VOC is formed during the incomplete combustion of the fuel. High combustion temperatures, adequate excess air and good fuel/air mixing during combustion will minimize VOC emissions.

The EPA BACT/LAER/RACT Clearinghouse has few BACT determinations for VOC emissions from bagasse combustion in boilers. Historically, BACT emission limits for VOC on bagasse and fuel oil fired boilers have been based on the use of good combustion practices, rather than add-on control system.

In bagasse-fired boilers, the fuel characteristics and the combustion practices result in VOC emissions that are somewhat high, relative to fossil fuel fired boilers. The use of flue gas recirculation (FGR) could theoretically reduce VOC emissions by reburning a portion of the VOCs in the recirculated exhaust. However, the overall effectiveness of FGR is limited and it has never been applied to a bagasse boiler.

Post combustion-VOC controls have not been applied to bagasse fired boilers. Such common techniques as direct-flame incineration, catalyst oxidation, and carbon absorption techniques were analyzed by the applicant and found not to be technically feasible technologies.

The applicant has proposed good combustion practices and an emission limit of 0.212 lb/MMBtu (bagasse) and 0.004 lb/MMBtu (fuel oil) emissions as BACT for VOC.

<u>Acid Gases</u> (SO_2, H_2SO_4, NO_x):

The emissions of sulfur dioxide, nitrogen oxides, and sulfuric acid mist represent a significant proportion of the total emissions and need to be controlled, if deemed appropriate. Sulfur dioxide emissions from boilers are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of very low-sulfur No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight, to control sulfur dioxide and sulfuric acid mist emissions. Fuel oil use will not exceed 10% of the maximum potential annual heat input.

The applicant has stated that BACT for nitrogen oxides will be met by using low-nitrogen fuel oil (maximum of 0.015% nitrogen content, by weight). When burning bagasse, NO_x emissions shall not exceed 0.25 lb/MMBtu.

Given the applicant's proposed BACT level for nitrogen oxides emissions, as stated above, an evaluation was made of the cost and associated benefit of using each one of the technologies available. The applicant identified the different available control technologies capable of reducing NO_x emissions as: Selective Non Catalytic Reduction (SNCR); Flue Gas Recirculation (FGR); Low-NO_x Burners (LNB); and, low-nitrogen fuel oil. This economic analysis was included in the application (see pages 5-19 through 5-30). The results of this analysis were included in Table 5-6 through Table 5-8.

The incremental cost effectiveness (ICE) values reported are: \$6,021/ton SNCR, \$10,561/ton using FGR, (\$26,725)/ton using LNB and \$9,621/ton using low-nitrogen fuel oil. The applicant has proposed the use of low-nitrogen fuel oil (max. 0.015% N content, by wt.) and very low-sulfur fuel oil (max. 0.05% S content, by wt.) as BACT for this emission unit.

<u>BACT Determination by Department:</u>

Based on the information presented by the applicant, the Department believes that the use of low-nitrogen fuel oil (oil firing shall not exceed 10% of the annual potential heat input), an emission limit of 0.25 lb/MMBtu (bagasse firing), and good combustion practices are justifiable as BACT for NO_x control.

For volatile organic compounds emissions, good combustion practices is determined as BACT for the proposed boiler.

For sulfur dioxide and sulfuric acid mist emissions, BACT is represented by firing very low-sulfur No. 2 fuel oil (max. 0.05% S content, by wt.).

For the heavy metal beryllium, BACT is being addressed through the particulate limitation of 0.04 lb/MMBTU, which will be achieved by the installation of an electrostatic precipitator as a control device.

The BACT emission limits for the U.S. Sugar Corporation project are thereby established as follows:

BACT EMISSION LIMITS

Pollutant	lb/MMBtu		lbs/hr	
	Bagasse	Oil	Bagasse	Oil
NO_x	0.25	0.20	185	50
SO_2	0.17	0.05	125	12.5
H_2SO_4	0.017	0.005	13	1.25
VOC	0.212	0.004	157	1.0

Details of the Analysis May be Obtained by Contacting:
Mr. Martin Costello, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

_____________________, 1994
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

_____________________, 1994
Date

UNITED STATES SUGAR CORPORATION
Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121

September 28, 1994

RECEIVED
SEP 30 1994
Bureau of
Air Regulation

Via Facsimile to (904) 922-6979

Teresa Heron, P. E.
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Fl. 32399-2400

Re: Clewiston Boiler No. 7 - Waiver

Dear Ms. Heron:

Enclosed please find a duly-signed waiver of the 90 day time limit in which DEP is normally required to approve or deny a construction permit application.

As discussed with Robert Van Voorhees, we understand that DEP expects to complete its review of all outstanding permit application issues as soon as practicable and issue its determination by October 31.

Sincerely,

UNITED STATES SUGAR CORPORATION

Murray T. Brinson
Vice President
Sugar Processing

MTB:jt
Attachment

cc: Clair Fancy, DEP, Tallahassee
John Brown, DEP, Tallahassee
Robert F. Van Voorhees, Bryan Cave

WAIVER OF 90 DAY TIME LIMIT

UNDER SECTIONS 120.60(2) AND 403.0876, FLORIDA STATUTES

Permit Application No: AC26-238006 & PSD-FL-208

Applicant's Name: UNITED STATES SUGAR CORPORATION - CLEWISTON BOILER NO. 7

The undersigned has read Sections 120.60(2) and 403.0876, Florida Statutes (F.S.), and fully understands the applicant's rights under that section.

With regard to the above referenced permit application, the applicant hereby with full knowledge and understanding of its rights under Sections 120.60(2) and 403.0876, F.S., waives the right under Sections 120.60(2) and 403.0876, F.S., to have the application approved or denied by the State of Florida Department of Environmental Protection within the 90 day period prescribed in Sections 120.60(2) and 403.0876, F.S. Said waiver is made freely and voluntarily by the applicant, in its self-interest, and without any pressure or coercion by anyone employed by the State of Florida Department of Environmental Protection.

This waiver shall expire on the 31st day of October 1994.

The undersigned is authorized to make this waiver on behalf of the applicant.

September 29, 1994
Date

Murray T. Brinson
Vice President, Sugar Processing
United States Sugar Corporation

September 23, 1994

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SEP 26 1994
Bureau of
Air Regulation

Ms. Teresa Heron
Florida Department of Environmental Protection
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Re: United States Sugar Corporation--Clewiston Boiler No. 7

Dear Ms. Heron:
At the request of United States Sugar Corporation (U.S. Sugar), and in follow up to our recent discussions, I am providing information related to the permit application and draft construction permit for Boiler No. 7.

PSD Source Applicability Analysis
Attached is a revised source applicability table for the project (Table II from the draft BACT determination). I have also developed an additional table (Table IIa) which presents the basis and calculations for the baseline emissions for Boilers 5 and 6. The footnotes at the bottom of Table IIa further explain the basis for the baseline emissions. Activity factors for calendar year 1992 and 1993 were used.

The only change in the calculations from our discussion is related to the baseline CO emissions. Upon further review of the available test data, I concluded that the CO test data from Clewiston Boiler 4 would be the most representative of CO emissions from Boilers 5 and 6, lacking any significant test data from Boilers 5 and 6. The test data from Clewiston Boiler 4 are attached. These are the same data that have been submitted in relation to the PSD permit application for Boiler 4 requesting that the CO limit be raised. The average CO emissions from Boiler 4, based on more than 60 individual test runs, was 6.7 lb/MMBtu. This is the emission factor used in Table IIa for the baseline CO emissions for Boiler 5 and Boiler 6.

The maximum emissions for proposed Boiler 7 for bagasse firing are based on the following:

PM - 0.04 lb/MMBtu
PM10 - 0.035 lb/MMBtu
SO_2 - 0.17 lb/MMBtu
NO_x - 0.25 lb/MMBtu
CO - 0.70 lb/MMBtu
VOC - 0.212 lb/MMBtu
Sulfuric acid mist - 0.017 lb/MMBtu

The PM10 limit of 0.035 lb/MMBtu is slightly lower than the limit requested by U.S. Sugar in Bryan Cave's submittal dated September 9, 1994. This limit is selected to avoid triggering PSD review for PM10 (see Table II).

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189
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The 0.25 lb/MMBtu limit for NO_x is also slightly lower than the limit requested in Bryan Cave's submittal dated September 9, 1994. As we discussed, the 0.25 lb/MMBtu limit is consistent with the BACT determination for Clewiston Boiler 4 issued in 1985 and reissued in 1987. I have attached copies of these determinations for your convenience. U.S. Sugar hereby requests that the NO_x BACT limit for Boiler 7 be set at 0.25 lb/MMBtu.

Proposed SO_2 Emission Limit

In regards to the proposed SO_2 emission limit of 0.17 lb/MMBtu when firing bagasse, the following discussion provides additional justification for this limit. In the original application for Boiler 7, the 0.17 lb/MMBtu limit was proposed, even though this limit was based on a wet scrubber for PM control, which was assumed to provide some SO_2 removal (32 percent removal based on theoretical SO_2 emissions). The PM control method now to be employed is an electrostatic precipitator (ESP). An acceptable SO_2 emission limit is based upon the fuel characteristics and any potential reduction in SO_2 in the boiler/ESP system.

U.S. Sugar has reviewed all available bagasse analysis from samples taken at Bryant and Clewiston mills. These data indicate an average sulfur content of 0.1 percent on a dry basis, with a theoretical SO_2 emission rate of 0.25 lb/MMBtu. There is some variability in sulfur content, generally ranging from 0.02 to 0.13 percent sulfur, dry basis. The sulfur content of a few isolated samples was even higher.

The SO_2 emission rate from the Boiler 7 stack will be a function of the sulfur content of the bagasse and any inherent removal in the boiler/ESP system. There are several reports published by the National Council for Air and Stream Improvement (NCASI) which indicate a significant degree of inherent SO_2 removal in wood/bark-fired boilers equipped with an ESP. There are several factors which affect the degree of removal, including the fuel composition, amount of free sulfur versus sulfate sulfur in the fuel, and the ash content and composition including metals composition. The reaction of sulfur, oxygen, and ash minerals to produce sulfates in the combustion process is responsible for preventing the full conversion of fuel sulfur to SO_2. The studies also indicate that sulfur removal increases with the time of contact with the flue gases, and with the fineness and alkalinity of the dust particles.

The NCASI studies indicate inherent SO_2 removal in wood/bark-fired boilers with ESP control to range as high as 90 percent and above. For the proposed Boiler 7, there are many unknowns, such as alkalinity of bagasse ash, effects of metals, effect of the ESP, free sulfur/sulfate sulfur ratios, etc. Therefore, such high removals may not be experienced. Bagasse-fired boilers have not been investigated insofar as inherent SO_2 removal. There are no operating bagasse boilers equipped with ESP control devices.

In spite of a lack of information for bagasse boilers, it is reasonable to expect some inherent SO_2 removal in the Boiler 7 boiler/ESP system. Based on the average sulfur content of bagasse, theoretical SO_2 emissions are approximately 0.25 lb/MMBtu. The proposed emission limit of 0.17 lb/MMBtu translates into an average inherent SO_2 removal of 32 percent. This degree of removal appears reasonable based on the available data from wood/bark-fired boilers. However, due to the large uncertainty, U.S. Sugar cannot agree to any lower emission rate. Testing after startup of the proposed boiler will confirm the actual SO_2 removal.

In regards to the Okeelanta and Osceola cogeneration projects, each of these projects was permitted for SO_2 limits of 0.1 lb/MMBtu (24-hour average) when burning biomass (i.e., bagasse and wood chips). However, these projects presented different fuel characteristics and sulfur contents than the U.S. Sugar data provide for its bagasse fuel. Okeelanta and Osceola have assumed a sulfur content of 0.009 percent (dry basis) for their biomass fuel, while U.S. Sugar's data show that bagasse alone has an average sulfur content of 0.1 percent (dry basis). U.S. Sugar's proposed technology is the same as that permitted for Okeelanta/Osceola, i.e., an ESP control device.

At an SO_2 emission rate of 0.17 lb/MMBtu while burning bagasse, the overall weighted average SO_2 emissions from Boiler 7 will be lower than from the Okeelanta Power facility. Assuming a 10 percent capacity factor for fuel oil, the weighted average SO_2 emissions from Boiler 7 will be 0.16 lb/MMBtu, while the weighted average SO_2 emissions from the Okeelanta Power boilers, as calculated by the Department in its September 17, 1993, BACT determination for Okeelanta Power, will be 0.21 lb/MMBtu. This average emission rate also compares favorably with rates determined as BACT for other power plants, including Bechtel Indiantown (0.17 lb/MMBtu) and OUC Stanton Unit 2 (0.25 lb/MMBtu), as cited by the Department in the Okeelanta Power BACT determination.

Modeling Analysis

In regards to the modeling analysis for proposed Boiler 7, Cleve Holladay has indicated that it will not be necessary to conduct any further modeling for Boiler 7. The existing modeling analysis can be used in conjunction with the revised emission rates to provide assurance that all ambient standards will be complied with by the project.

Professional Engineer's Certification

Finally, by means of this letter, I hereby certify that the engineering calculations and other information presented in Bryan Cave's submittal dated September 9, 1994, as well as the information contained in this letter, have been examined by me and found to be in conformity with good engineering principles and practices.

Please call if you have any questions concerning this matter.

Sincerely,

David A. Buff

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

SEAL

DABuff/vjp
cc: Don Griffin
Murray Brinson
Peter Briggs
Bob Van Vorhees
File (2)

Table II. Revised PSD Source Applicability Analysis for U.S. Sugar Clewiston Boiler No. 7

Regulated Pollutant	Contemporaneous Decreases (TPY)[a] Boiler 5	Boiler 6	Totals	Increases Due To Boiler No. 7 (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	52.8	59.3	112.1	129.3 [b]	17.2	25	No
Particulate (PM10)	47.6	53.3	100.9	113.1 [c]	12.2	15	No
Sulfur dioxide	11.1	12.3	23.5	549.5	526.05	40	Yes
Nitrogen oxides	26.4	29.6	56.1	808.1 [d]	752.05	40	Yes
Carbon monoxide	1,180.1	1,323.7	2,503.8	2,262.7 [e]	-241.1	100	No
Volatile org. compds.	44.0	49.4	93.4	685.3	591.85	40	Yes
Lead	--	--	--	0.018	0.018	0.6	No
Mercury	--	--	--	0.0021	0.0021	0.1	No
Beryllium	--	--	--	0.0027	0.0027	0.0004	Yes
Fluorides	--	--	--	0.0041	0.0041	3	No
Sulfuric acid mist	1.1	1.2	2.35	55.0 [f]	52.6	7	Yes
Total reduced sulfur	--	--	--	--	--	10	No
Asbestos	--	--	--	--	--	0.007	No
Vinyl Chloride	--	--	--	--	--	0	No

[a] Refer to Table IIa for basis of baseline emissions.
[b] Based on PM emission limit of 0.040 lb/MMBtu.
[c] Based on PM10 emission limit of 0.035 lb/MMBtu.
[d] Based on NOx emission rate of 0.25 lb/MMBtu.
[e] Based on CO emission rate of 0.70 lb/MMBtu.
[f] Based on 10% of SO2 emissions.

CLEW7NET
09/22/94

Table IIa. Baseline Emissions for Clewsiton Boilers 5 and 6

Regulated Pollutant	Emission Factor	Boiler 5 Activity Factor	Boiler 5 Emission Rate (TPY)	Boiler 6 Activity Factor	Boiler 6 Emission Rate (TPY)
Particulate (TSP)	0.3 lb/MMBtu[a]	3.52E+11 Btu/yr	52.8	3.95E+11 Btu/yr	59.3
Particulate (PM10)	90% of PM[b]	--	47.6	--	53.3
Sulfur dioxide	0.5 lb/ton[c]	44,470 tons/yr	11.1	49,392 tons/yr	12.3
Nitrogen oxides	1.2 lb/ton[d]	44,035 tons/yr	26.4	49,392 tons/yr	29.6
Carbon monoxide	6.7 lb/MMBtu[e]	3.52E+11 Btu/yr	1,180.1	3.95E+11 Btu/yr	1,323.7
Volatile org. compds.	2.0 lb/ton[f]	44,035 tons/yr	44.0	49,392 tons/yr	49.4
Lead	--	--	--	--	--
Mercury	--	--	--	--	--
Beryllium	--	--	--	--	--
Fluorides	--	--	--	--	--
Sulfuric acid mist[e]	10% of SO2	--	1.1	--	1.2
Total reduced sulfur	--	--	--	--	--
Asbestos	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--

[a] Based on allowable PM emission rate.
[b] Based on limited source testing conducted on bagasse boilers.
[c] Based on 0.1% sulfur content for wet bagasse.
[d] Based on AP-42 factor.
[e] Based on average CO emission rate of 6.7 lb/MMBtu from actual stack testing conducted on Clewiston Boiler No. 4.
[f] Based on NEDS Source Classification Code manual emission factor.

Note: Activity factors based on actual operation as follows:

Average bagasse heating value = 4,000 Btu/lb

Year	Boiler 5 Wet Bagasse (TPY)	Boiler 5 Heat Input (Btu/yr)	Boiler 6 Wet Bagasse (TPY)	Boiler 6 Heat Input (Btu/yr)
1992	43,599	3.49E+11	52,912	4.23E+11
1993	44,470	3.56E+11	45,871	3.67E+11
2-Year Average:	44,035	3.52E+11	49,392	3.95E+11

Table B1. Summary of CO Emission Tests Performed on Clewiston Boiler No. 4 Using EPA Method 10

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input (MMBtu/hr)	Bagasse Firing Rate^a (TPH wet)	CO Emissions lb/hr	CO Emissions lb/MMBtu	CO Emissions lb/ton,wet	CO Emissions Compliance Average lb/MMBTU
U.S. Sugar - Clewiston									
Boiler 4	Traveling Gate	02/20/90	308,636	691.7	96.07	1,940	2.79	20.19	2.75
Boiler 4	Traveling Gate	02/20/90	306,666	690.3	95.87	1,520	2.24	15.85	
Boiler 4	Traveling Gate	02/20/90	310,298	698.8	97.06	2,240	3.23	23.08	
Boiler 4	Traveling Gate	02/15/91	289,091	624.9	86.79	4,760	7.62	54.84	5.27
Boiler 4	Traveling Gate	02/15/91	291,200	629.5	87.43	2,710	4.30	31.00	
Boiler 4	Traveling Gate	02/15/91					3.90		
Boiler 4	Traveling Gate	02/18/91	288,358	622.8	86.50	2,430	3.90	28.09	3.78
Boiler 4	Traveling Gate	02/18/91	285,224	616.4	85.61	2,640	4.28	30.84	
Boiler 4	Traveling Gate	02/18/91	302,647	653.3	90.74	2,060	3.16	22.70	
Boiler 4	Traveling Gate	02/19/91	290,769	627.9	87.21	4,430	7.05	50.80	5.43
Boiler 4	Traveling Gate	02/19/91	294,583	637.1	88.49	3,400	5.33	38.42	
Boiler 4	Traveling Gate	02/19/91	293,382	633.5	87.99	2,480	3.92	28.19	
Boiler 4	Traveling Gate	02/22/91	300,000	647.9	89.99	4,900	7.56	54.45	11.23
Boiler 4	Traveling Gate	02/22/91	293,382	634.2	88.08	9,450	14.90	107.28	
Boiler 4	Traveling Gate	01/07/92	293,425	613.6	85.22	3,200	5.22	37.55	7.91
Boiler 4	Traveling Gate	01/07/92	282,800	591.3	82.12	6,270	10.60	76.35	
Boiler 4	Traveling Gate	01/08/92	299,178	623.2	86.56	2,030	3.26	23.45	4.66
Boiler 4	Traveling Gate	01/08/92	297,973	621.5	86.32	3,160	5.09	36.61	
Boiler 4	Traveling Gate	01/08/92	300,811	627.4	87.14	3,540	5.64	40.62	
Boiler 4	Traveling Gate	01/09/91	302,055	630.0	87.50	2,770	4.40	31.66	4.40
Boiler 4	Traveling Gate	01/09/91	295,135	615.8	85.53	2,710	4.40	31.69	
Boiler 4	Traveling Gate	01/13/93					7.50		8.03
Boiler 4	Traveling Gate	01/13/93					8.59		
Boiler 4	Traveling Gate	01/13/93					7.99		
Boiler 4	Traveling Gate	01/14/93					15.00		11.48
Boiler 4	Traveling Gate	01/14/93					7.95		
Boiler 4	Traveling Gate	02/02/93					7.19		7.94
Boiler 4	Traveling Gate	02/02/93					6.71		
Boiler 4	Traveling Gate	02/02/93					9.92		
Boiler 4	Traveling Gate	02/04/93					6.78		7.64
Boiler 4	Traveling Gate	02/04/93					9.13		
Boiler 4	Traveling Gate	02/04/93					7.01		
Boiler 4	Traveling Gate	01/13/94		628.52			5.55		7.37
Boiler 4	Traveling Gate	01/13/94		614.06			5.26		
Boiler 4	Traveling Gate	01/13/94		615.24			11.31		
Boiler 4	Traveling Gate	01/14/94		639.11			5.18		9.59
Boiler 4	Traveling Gate	01/14/94		629.38			6.11		
Boiler 4	Traveling Gate	01/14/94		635.50			17.49		
Boiler 4	Traveling Gate	02/01/94		592.17			1.84		5.22
Boiler 4	Traveling Gate	02/01/94		595.17			8.59		
Boiler 4	Traveling Gate	02/07/94		587.52			4.65		7.53
Boiler 4	Traveling Gate	02/07/94		599.46			5.47		
Boiler 4	Traveling Gate	02/07/94		582.08			13.03		
Boiler 4	Traveling Gate	02/07/94		586.88			6.97		
Boiler 4	Traveling Gate	02/09/94		620.29			6.99		6.99
Boiler 4	Traveling Gate	02/11/94		622.97			5.78		4.43
Boiler 4	Traveling Gate	02/11/94		580.67			1.53		
Boiler 4	Traveling Gate	02/11/94		625.28			7.89		
Boiler 4	Traveling Gate	02/11/94		644.24			2.51		
Boiler 4	Traveling Gate	02/17/94		608.74			9.47		6.95
Boiler 4	Traveling Gate	02/17/94		584.52			4.86		

Boiler 4	Traveling Gate	02/17/94	623.65		6.68		
Boiler 4	Traveling Gate	02/17/94	631.71		6.78		
Boiler 4	Traveling Gate	02/22/94	625.33		7.48		7.70
Boiler 4	Traveling Gate	02/22/94	633.82		7.38		
Boiler 4	Traveling Gate	02/22/94	616.86		7.58		
Boiler 4	Traveling Gate	02/22/94	585.45		7.99		
Boiler 4	Traveling Gate	02/22/94	580.29		8.06		
Boiler 4	Traveling Gate	02/23/94	616.93		3.99		5.48
Boiler 4	Traveling Gate	02/23/94	633.14		6.07		
Boiler 4	Traveling Gate	02/23/94	617.98		6.39		
Boiler 4	Traveling Gate	03/04/94	636.45		3.02		3.99
Boiler 4	Traveling Gate	03/04/94	614.71		2.34		
Boiler 4	Traveling Gate	03/04/94	598.50		4.21		
Boiler 4	Traveling Gate	03/04/94	625.69		6.38		
				Max. =	17.49	107.28	11.48
				Avg. =	6.48	39.18	6.63

Note: lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
NA = not available.
TPH = tons per hour.

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[a] Calculated from reported heat input rate, assumed 3,600 Btu/lb average heat content for wet bagasse.

MEMO FROM ROBERT F. VAN VOORHEES

TO: Teresa Heron

DATE: September 13, 1994

RE: **Bryant Boiler No. 5**

Attached is the permit for Bryant Boiler No. 5 to which I referred in our telephone conversation. Specific condition No. 14 was reviewed and approved as acceptable under the Howard Rhodes memorandum dated February 11, 1994: Guidance on Rate of Operation During Compliance Testing for All Sources Except Combustion Turbines.

Robert Van Voorhees

Attachment

BRYAN CAVE
700 THIRTEENTH STREET, N.W.
WASHINGTON, D.C. 20005-3960

DIRECT NUMBER: (202) 508-6014
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BRYAN CAVE

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ROBERT F. VAN VOORHEES
DIRECT DIAL NUMBER
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September 9, 1994

RECEIVED
SEP 14 1994
Bureau of
Air Regulation

Teresa M. Heron
Florida Department of
Environmental Protection
Bureau of Air Regulation
111 South Magnolia
Suite 4
Tallahassee, FL 32301

Re: Comments on Draft Permit and BACT Determination for <u>United States Sugar Corp. -- Clewiston Boiler No. 7</u>

Dear Ms. Heron:

Thank you for providing us the opportunity to review the draft PSD permit and BACT determination for Clewiston Boiler No. 7. We have found this opportunity for review extremely helpful. Having the opportunity to review these drafts now should save a significant amount of our time and yours by allowing us to identify and resolve concerns that we may have over the detailed provisions of the permit at this preliminary stage without having to resort to the hearing process later.

Enclosed for your consideration are comments on the draft documents. We have suggested a number of revisions and have tried in each case to explain the reasons for suggesting a revision.

In some cases, our review of the data and requirements has led to a conclusion that different emission limits are warranted. This is especially true for particulate matter and carbon monoxide, where the adoption of an ESP to control particulate matter and the redesign of the boiler to control carbon monoxide has resulted in such substantial reductions of the emissions of these pollutants (below the emission levels for the boilers that will be replaced) that PSD analysis is no longer required. In these cases, we have opted for less stringent emission limits because of our concerns, based on discussions with equipment manufacturers, over the ability of the control technology to meet the more stringent limits. In both cases, the data support adoption of the less stringent emission limits that we have proposed.

In addition, U.S. Sugar is requesting the Department's approval of an alternative monitoring approach for opacity. In light of the infrequency with which Boiler No. 7 will be burning No. 2 fuel oil and in light of the low ash content of No. 2 fuel oil emissions, U.S. Sugar hereby requests pursuant to 40 C.F.R. § 60.13(i) that the Department establish and approve an alternative monitoring requirement for opacity -- namely, a requirement that a video camera be installed and focused on the stack for Boiler No. 7 and that the camera be operated when No. 2 fuel oil is burned in the boiler.

We hope that adequate explanations have been provided for all of the comments presented. Please call me (202-508-6014) if you have any questions or need any clarification of the comments. We look forward to working with you to finalize this permit.

Sincerely,

Robert F. Van Voorhees

Robert F. Van Voorhees

Enclosures

cc: Murray Brinson
Peter Briggs
Donald Griffin

86500.01

COMMENTS ON DRAFT BACT DETERMINATION FOR
UNITED STATES SUGAR CORPORATION
Boiler No. 7 - PSD-FL-208
Hendry County

September 9, 1994

Best Available Control Technology (BACT) Determination
U. S. Sugar Corporation
Boiler No. 7 - PSD-FL-208
Hendry County

The applicant proposes to install a new bagasse and fuel oil fired boiler at **its** ~~the~~ Clewiston sugar mill. This new boiler~~,~~ ~~unit~~ No. 7, will provide steam to the sugar **cane processing** ~~refining~~ operations. Two existing bagasse boilers (No. 5 and 6) will be retained on standby. In addition, U.S. Sugar Corporation is proposing to raise the stacks of the existing **B**~~b~~oiler**s** No. 1, 2 and 3 to 150 feet above grade.

COMMENTS:

A. **The indicated revisions are proposed for purposes of correction and clarification. U.S. Sugar does not conduct sugar "refining" operations at the Clewiston Mill. U.S. Sugar numbers its boilers at the Clewiston Mill, but does not number its other "units" for which air permits have been issued by the Department.**

The boiler will combust primarily bagasse to generate **an average of** ~~up to~~ 350,000 lb/hr of steam for the mill. The total heat input of boiler No. 7 at this ~~maximum~~ steam production rate will be 738 MMBtu/hr. Steam production due to fuel oil firing will be ~~limited to~~ **approximately 175,000** ~~75,850~~ lb/hr. Heat input from No. 2 fuel oil (0.05% S) shall not exceed **250** ~~255 S~~ MMBtu/hr. The consumption of oil shall not exceed 10% of the total **potential** heat input to the boiler in any calendar year. Table I lists the pollutants **potentially** subject to PSD analysis. Table II shows the PSD source applicability. The applicant has proposed the maximum annual tonnage of regulated air pollutants emitted from this boiler based on **operation for** 8760 hours per year (burning bagasse).

COMMENTS:

B. **The permit will allow a one-hour maximum steam production rate of 385,000 lb/hr, but the meaningful rate for purposes of this analysis is the long-term average of 350,000 lb/hr.**

The suggested clarification should be made to avoid confusing these two steam production rates.

C. The approximate steam production rate while burning fuel oil, as stated in Specific Condition No. 9 of the draft permit is 175,000 lb/hr. This figure, which is not expressed as a limitation in the permit, should be used consistently.

D. Heat input from No. 2 fuel oil will be limited to 250 MM Btu/hr, and the consumption of oil will be limited to 10% of the total "potential" heat input from bagasse combustion assuming that the boiler is operated 8,760 hours per calendar year, as provided in the definition of "annual capacity factor" in 40 C.F.R. § 60.41b. The word "potential" should be inserted for clarification.

TABLE I

Boiler No. 7

Pollutant	Potential Emissions (Tons/Yr)		PSD Significant Emission Rate (Tons/Yr)
	Oil	Bagasse	
NO_x	64.40 ~~28.62~~	840	40
SO_2	16.10 ~~10.16~~	550 ~~540~~	40
PM/PM_{10}	12.88 ~~6.44~~	129 ~~97~~	25
CO	21.25 ~~7.16~~	2,262 ~~1,131~~	100
VOC	1.29 ~~0.29~~	689	40
H_2SO_4	1.61 ~~0.05~~	55	7
Be	0.003 ~~8.4E-06~~		0.0004
Hg	0.002 ~~6.4E-06~~		0.1
Pb	0.02 ~~56E-06~~		0.6

Florida Administrative Code Rule 17-2.410 requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

COMMENTS:

E. For No. 2 fuel oil, the nitrogen oxides emission level can be set at 0.20 lb/MM Btu. Since the heat input rate will remain at or below 250 MM Btu/hr while the boiler is burning No. 2 fuel oil, no emission limit is dictated for nitrogen oxides by the new source performance standard (NSPS) in 40 C.F.R. Subpart 60 Db. Accordingly, it is appropriate to set an emission level of 0.20 lb/MM Btu to reflect the emission level that will be achieved through the use of No. 2 fuel oil. Assuming a rate of 0.20 lb/MM Btu, the annual nitrogen oxides emission rate for No. 2 fuel oil is 64.40 tons/yr.

F. For nitrogen oxides emissions during bagasse combustion, the demonstrated BACT emission level is 0.26 lb/MM Btu as presented in the U.S. Sugar analysis submitted on June 27, 1994. (The grounds supporting adoption of this level are presented below in the comments on the draft detailed BACT determination.) Based on an emission rate of 0.26 lb/MM Btu, the hourly level should be 192 lb/hr, and the annual level should be 840 ton/yr.

G. For sulfur dioxide, the potential emissions should be stated as 550 tons/yr for bagasse, and 16.10 tons/yr for No. 2 fuel oil. The emission level should be 0.17 lb/MM Btu for bagasse rather than 0.16 lb/MMBtu, as stated in Specific Condition No. 1 of the draft permit, because the level proposed was 0.167 lb/MMBtu, which should be rounded to 0.17 lb/MMBtu rather than 0.16 lb/MMBtu. The correct hourly bagasse level for sulfur dioxide then becomes 125 lb/hr, and the correct annual level is 550 tons/yr.

For a sulfur dioxide emission level of 0.05 lb/MMBtu for No. 2 fuel oil, the correct hourly rate is 12.5 lb/hr for a heat input rate of 250 MM Btu/hr. The annual emission level for sulfur dioxide is 16.10 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The heating value for No. 2 fuel oil is assumed to be 140,000 Btu/gal.

H. The emission level for particulate should be 12.88 tons/yr for oil and 129 tons/yr for bagasse. U.S. Sugar proposes to use an emission rate of 0.04 MM Btu/hr to reflect the control level that can be achieved through the use of an ESP, and that level of control results in a net increase in emissions that does not exceed the level necessary to trigger a PSD analysis requirement. The hourly emission level for particulate is 10 lb/hr for No. 2 fuel oil assuming a heat input level of 250 MM Btu/hr and a limit of

0.04 lb/MM Btu, and the annual level is 12.88 tons per year assuming maximum fuel oil combustion at the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The proper hourly emission value for bagasse, assuming particulate emissions at 0.04 lb/MM Btu with a heat input of 738 MM Btu/hr, is 30 lb/hr. This yields potential annual emissions for particulate of 129.3 tons per year assuming operation for 8760 hrs per year.

I. For carbon monoxide, U.S. Sugar proposes an emission level of 0.70 lb/MM Btu while burning bagasse, which results in an annual emission level of 2,262 tons/yr -- a level still substantially below the current CO emissions from Boilers Nos. 5 and 6. At this level, PSD does not apply. Therefore, no BACT analysis is required for CO, and all discussion of CO should be deleted from the BACT determination.

For a carbon monoxide emission level of 0.066 lb/MM Btu for No. 2 fuel oil, the correct hourly rate is 16.5 lb/hr for a heat input rate of 250 MM Btu/hr, and the annual emission level for carbon monoxide while burning No. 2 fuel oil is 21.25 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor.

J. For a volatile organic compound (VOC) emission level of 0.004 lb/MM Btu for No. 2 fuel oil, the correct hourly rate is 1.0 lb/hr for a heat input rate of 250 MM Btu/hr, and the annual VOC emission level while burning No. 2 fuel oil is 1.29 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor.

K. For a sulfuric acid mist emission level of 0.005 lb/MMBtu for No. 2 fuel oil, the correct hourly rate is 1.25 lb/hr for a heat input rate of 250 MM Btu/hr, and the annual emission level for sulfuric acid mist is 1.61 ton/yr while burning No. 2 fuel oil assuming maximum fuel oil combustion under the 10% annual capacity factor. For bagasse burning, the sulfuric acid mist emission level should be 0.017 lb/MM Btu rather than 0.016 lb/MMBtu because the level proposed was 0.0167 lb/MMBtu, which should be rounded to 0.017 lb/MMBtu rather than 0.016 lb/MMBtu. The correct hourly level for sulfur dioxide then becomes 13 lb/hr, and the correct annual level is 55 tons/yr.

L. Particulate matter and carbon monoxide should be deleted from the BACT analysis entirely because neither pollutant will be emitted at levels requiring a BACT analysis.

For the remaining pollutants, the correct annual emission levels should be 0.018 tons/yr for lead, 0.0021 tons/yr for

mercury, and 0.0027 tons/yr for beryllium. (The PSD Significant Emission Rate for beryllium is 0.0004 tons/yr rather than 0.004 tons/yr.)

Table II. Revised PSD Source Applicability for U.S. Sugar Clewiston Boiler No. 7

Regulated Pollutant	Contemporaneous Decreases (TPY) Boiler 5	Boiler 6	Total	Increases Due To Boiler No. 7 (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	57.6	69.9	127.5	129.3[c]	1.8	25	No
Particulate (PM10)	51.8[a]	62.9[a]	114.8	129.3[c]	14.6	15	No
Sulfur dioxide	12.0	14.6	26.6	549.5	522.9	40	Yes
Nitrogen oxides	28.8	34.9	63.7	840.0	776.3	40	Yes
Carbon monoxide	1,728.0	2,096.0	3,824.0	2,262.0[d]	-1562.0	100	No
Volatile Org. Compds.	48.0	58.2	106.2	689.0	582.8	40	Yes
Lead	--	--	--	0.018	0.018	0.6	No
Mercury	--	--	--	0.0021	0.0021	0.1	No
Beryllium	--	--	--	0.0027	0.0027	0.0004	Yes
Fluorides	--	--	--	0.0041	0.0041	3	No
Sulfuric acid mist[b]	1.20	1.46	2.66	55.0	52.3	7	Yes
Total reduced sulfur	--	--	--	--	--	10	No
Asbestos	--	--	--	--	--	0.007	No
Vinyl Chloride	--	--	--	--	--	0	No

a Based on 90% of PM emissions.
b Based on 10% of SO_2 emissions.
c Based on PM emission limit of 0.04 lb/MMBtu.
d Based on CO emission rate of 0.70 lb/MMBtu.

<u>Date of Receipt of a BACT Application:</u>

September 17, 1993

<u>BACT Determination Requested by the Applicant:</u>

<u>Pollutant</u>	<u>Determination</u>
NO_x	Low NO_x-nitrogen oil Bagasse-firing: **<u>0.26</u>** ~~0.20~~ lb/MMBtu Oil-firing: **<u>0.2</u>** ~~0.1 - 0.2~~ lb/MMBtu ~~(low to high heat release)~~

COMMENTS:

M. The numbers for nitrogen oxide emissions should be revised to agree with the numbers presented in Specific Condition No. 1 of the permit.

VOC	Good Combustion practices
~~CO~~	~~Good Combustion practices and 0.35 lb/MMBtu~~
SO_2	Firing **<u>very</u>** low-sulfur **<u>No. 2 fuel</u>** ~~diesel~~ oil (maximum of 0.05% sulfur), not to exceed 10% of the total annual heat input. Bagasse: 0.16 lb SO_2/MMBtu Oil: 0.05 lb SO_2/MMBtu

N. The CO analysis should be dropped from the BACT Determination because no PSD review is required beyond confirmation that this project results in a net reduction in CO emissions, and no BACT analysis is required.

The term "very low sulfur oil" or some variation that includes an explanation that the sulfur content will be no more than 0.05 weight percent sulfur -- e.g., "very low sulfur oil (0.05% S)" should be used consistently to refer to the No. 2 fuel oil that will be burned in Boiler No. 7. Reference to No. 2 fuel oil rather than "diesel" should also be used consistently throughout the permit and BACT determination to avoid confusion with diesel motor fuels that include dyes and other fuel additives that would

be inappropriate for combustion in Boiler No. 7.

H_2SO_4	Firing of low-sulfur diesel oil (maximum of 0.05% sulfur)
Be	Electrostatic Precipitator
~~PM and PM_{10}~~	~~Electrostatic Precipitator~~ ~~Bagasse: 0.03 lb/MMBtu~~ ~~Oil: 0.03 lb/MMBtu~~

COMMENTS:

O. References to particulate matter should be deleted since there is no requirement for a PSD determination with respect to particulate matter. Otherwise, the references to ESP control should be amended to reflect the 0.04 lb/MM Btu level reflected in Specific Condition No. 1 of the permit.

BACT DETERMINATION PROCEDURE

In accordance with Rule 17-212.410, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted above the significance levels which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, 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).

(b) All scientific, engineering, and technical material and other information available to the Department

(c) The emission limiting standards or BACT determination of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. The air pollutant emissions from this boiler can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels.0
- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- Acid Gases (SO_x, NO_x, HC1, Fl, H_2SO_4). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT ANALYSIS

Combustion Products (Be):

U.S. Sugar Corporation's projected contemporaneous emission rate changes for particulate matter, PM_{10}, are below the significant emission rates since they are controlled by an electrostatic precipitator. Beryllium emissions are subject to PSD review because they are above the significant levels as given in Florida Administrative Code Rule 17-2.400, Table 212.400-2. In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium from boilers. BACT for these heavy metals is typically represented by the level of particulate control. As this is the case, the emission factor of **<u>0.04</u>** ~~0.03~~ lb/MmBtu for particulate matter PM_{10} is judged to also represent BACT for beryllium.

COMMENTS:

P. The discussion of beryllium BACT should be revised to reflect the correct particulate matter emission level of 0.04 lb/MM Btu.

<u>Products of Incomplete Combustion</u> (~~CO,~~ VOC):

The emissions of ~~carbon monoxide and~~ volatile organic compounds are ~~each~~ above the significant level and therefore do require a BACT analysis. ~~Carbon monoxide and~~ VOC ~~are~~ is formed during the incomplete combustion of the fuel. High combustion temperatures, adequate excess air and good fuel/air mixing during combustion will minimize ~~CO and~~ VOC emissions.

The EPA BACT/LAER/RACT clearinghouse has few BACT determinations for ~~CO or~~ VOC emissions from bagasse combustion in boilers. Historically, BACT emission limits for ~~CO and~~ VOC on bagasse and oil-fired boilers have been based on the use of good combustion practices, rather than add-on control system.

In bagasse-fired boilers, the fuel characteristics and the combustion practices result in ~~CO and~~ VOC emissions that are somewhat high, relative to fossil-fuel fired boilers. The use of flue gas recirculation (FGR) could theoretically reduce ~~CO and~~ VOC emissions by reburning a portion of the VOCs in the recirculated exhaust. However, the overall effectiveness of FGR is limited and it has never been applied to a bagasse boiler.

Post combustion-VOC controls have not been applied to bagasse-fired boilers. Such common techniques as direct-flame incineration, catalyst oxidation, and carbon absorption techniques were analyzed by the applicant and found **<u>not</u>** ~~them~~ to be ~~not~~ technically feasible technologies.

COMMENTS:

Q. References to CO should be dropped because no BACT analysis is required for CO. The other revisions are proposed for clarification purposes.

The applicant has proposed good combustion practices and an emission limit of ~~0.35 lb/MMBtu (bagasse burning) and 0.066 0.1 to 0.2 lb/MMBtu (oil burning) as BACT for CO and~~ 0.21<u>2</u> lb/MmBtu (bagasse burning) and 0.004 lb/MMBtu (oil burning) emissions as BACT for VOC.

COMMENTS:

R. The discussion of CO should be deleted, and any references to CO should be at the 0.70 lb/MM Btu emission limit for bagasse and 0.066 lb/MM Btu for No. 2 fuel oil.

This 0.212 lb/MM Btu level for VOC is substantially below the 5.0 lb/MM Btu level established by rule as RACT for carbonaceous boilers and the 1.5 lb/MM Btu level recently proposed by U.S. Sugar and other bagasse boiler operators as RACT for existing bagasse boilers. It is also below the lowest level established as RACT for any bagasse boiler (0.26 lb/MM Btu).

<u>Acid Gases</u> (SO_2, H_2SO4, NO_X):

The emissions of sulfur dioxide, nitrogen oxides, and sulfuric acid mist, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from boilers <u>**are**</u> ~~is~~ directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of very low-sulfur <u>**No. 2 fuel oil**</u> ~~distillate (diesel)~~ with a maximum sulfur content of 0.05% to control sulfur dioxide and sulfuric acid mist emissions. Fuel oil use will not exceed 10% of the ~~total~~ <u>**maximum potential**</u> annual heat input.

COMMENTS:

S. Reference to No. 2 fuel oil should be used consistently throughout the permit and BACT determination to avoid confusion with diesel motor fuels that include dyes and other fuel additives that would be inappropriate for combustion in Boiler No. 7.

T. The term "maximum potential" should be used to agree with the regulatory definition of "annual capacity factor" in 40 C.F.R. § 60.41b.

The applicant has stated that BACT for nitrogen oxides will be met by using low-nitrogen oil. When burning bagasse, NOx emissions shall not exceed <u>**0.26**</u> ~~0.20~~ lb/MMBtu.

COMMENTS:

U. **For nitrogen oxides, the demonstrated BACT emission level is 0.26 lb/MM Btu as presented in the U.S. Sugar analysis submitted on June 27, 1994. The grounds supporting adoption of this level are discussed in the remaining portion of this BACT determination. U.S. Sugar presented this emission level based on discussions with boiler manufacturers who are prepared to supply boilers that can achieve this level of control using the proposed BACT.**

U.S. Sugar has elected to propose the level of control that reflects more of a consensus among boiler manufacturers. For the reasons explained in the remainder of the Department's draft BACT analysis and determination, this level should be adopted and included in the permit. As explained in Comment V, this level is not inconsistent with any prior BACT determination by the Department or with the needs of Hendry County, which is not a nonattainment area for any national ambient air quality standard (NAAQS).

~~A review of the Florida BACT Determination for bagasse boilers indicates that the lowest NO_x emission limit established to date for a bagasse/coal/oil fired boiler is 0.15 lb/MmBtu. This level of control was achieved through the installation of selective non catalytic reduction (SNCR). It should be noted that the bagasse/coal/oil fired boiler (Okeelanta Power) with the 0.15 lb/MMBtu NO_x limitation, is located in a nonattainment area for ozone (Palm Beach County).~~

COMMENTS:

V. **This paragraph should be deleted or revised because it does not present an accurate explanation of the Department's prior determinations. In the case of Okeelanta Power, no BACT determination was made by the Department because overall project emissions of NOx would not exceed the baseline emissions at the site -- i.e., the elimination of NOx emissions from the existing boilers at that site would more than offset the emissions from the new boilers.**

The only determination actually made by the Department for Okeelanta Power was a determination that the 0.15 lb/MM Btu emission level proposed by Okeelanta was sufficient to satisfy the requirements for the use of reasonably available control technology (RACT). The level proposed by Okeelanta was a control level sufficient to achieve a net reduction in nitrogen oxides emissions for the project and a level lower than that mandated by the new source performance standard (NSPS) for electric utility steam generating units (40 C.F.R. Subpart 60 Da) -- a requirement that does not apply

to Clewiston Boiler No. 7. The Department did not determine that this level of control is mandated by the applicable RACT requirement, nor would the Department have done so. Instead, the Department has determined by rule in F.A.C. § 17-296.570 that a nitrogen oxides emission level of 0.9 lb/MM Btu is sufficient to satisfy the RACT requirement for bagasse boilers. The 0.26 lb/MM Btu level proposed by U.S. Sugar is substantially (more than 70%) below the RACT level established by the Department.

Thus, the Department has not made a BACT determination at any level below the 0.26 lb/MM Btu level proposed by U.S. Sugar. The level proposed by U.S. Sugar should be adopted on the basis of the Department's proposed BACT determination.

Given the applicant's proposed BACT level for nitrogen oxides emissions stated above, an evaluation was made of the cost and associated benefit of using each one of the technologies. This economic analysis was included in the application (see page 5-19 through 5-30). The results of this analysis were included in Table 5-6 through Table 5-8.

The applicant identified the different available control technologies capable of reducing NO_x emissions. These technologies are: Selective Non Catalytic Reduction (SNCR), Flue Gas Recirculation (FGR), Low NO_x Burners (LNB), and Low-Nitrogen oil.

The incremental cost effectiveness (ICE) values reported are: $6,021/ton SNCR, $10,561/ton using FGR, ($26,725)/ton using LNB and $9,621/ton using low-nitrogen fuel. The applicant has proposed the use of low-nitrogen (0.015% N) **<u>and very</u>** low-sulfur (0.05% S) **<u>No. 2</u>** ~~diesel~~ fuel oil as BACT for this source.

COMMENTS: (See Comments N and S, above.)

<u>BACT Determination by DEP:</u>

Based on the information presented by the applicant the Department believes that the use of low nitrogen fuel oil (oil firing shall not exceed 10% of the annual capacity factor), an emission limit of **<u>0.26</u>** ~~0.20~~ lb/MMBtu (bagasse firing), and good combustion practices are justifiable as BACT for NOX control.

COMMENTS: Correct to agree with the 0.26 lb/MM Btu control level proposed by U.S. Sugar. (See Comment U, above.)

For carbon monoxide and volatile organic compounds emissions, good combustion practices is determined as BACT for the proposed boiler.

For sulfur dioxide and sulfuric acid mist emissions, BACT is represented by firing **very** low-sulfur **No. 2** ~~diesel~~ fuel oil (maximum of 0.05% sulfur).

COMMENTS: (See Comments N and S, above.)

For the heavy metal beryllium BACT is being addressed through the particulate limitation of 0.04 lb/MM Btu, which will be achieved by the installation of an electrostatic precipitator as a control device.

~~For PM and PM_{10} emissions, emission reduction is accomplished by the installation of an electrostatic precipitator as a control device. This method of control has been determined as BACT for a similar facility. BACT for the heavy metal beryllium is being addressed through the particulate limitation.~~

COMMENTS: (See Comments O and P, above.)

The emission limits for the U.S. Sugar Corporation project are thereby established as follows:

BACT EMISSION LIMIT

	Lb/MMBtu		Lb/Hr	
Pollutant	Bagasse	Oil	Bagasse	Oil
NO_x	**0.26** ~~0.20~~	~~0.1~~0.20	**192** ~~148~~	**50**
SO_2	**0.17** ~~0.16~~	0.05	**125** ~~123~~	**12.5**
~~H_2SO_4~~	~~0.017 0.016~~	~~0.005 0.05~~	~~13 157~~	~~1.25~~
VOC	0.212	**0.004** ~~0.066~~	**157** ~~258~~	**1.0**
~~CO~~	~~0.70 0.35~~	~~0.066~~	~~516~~	~~16.6~~
~~Be~~		~~8.4E-06~~		
~~PM/PM_{10}~~	~~0.03~~	~~0.03~~	~~22~~	

COMMENTS:

W. For nitrogen oxides, the demonstrated BACT emission level is 0.26 lb/MM Btu as presented in the U.S. Sugar analysis submitted on June 27, 1994. The grounds supporting adoption of this level are presented above in Comments U and V. Based on an emission rate of 0.26 lb/MM Btu, the hourly level for nitrogen oxides should be 192 lb/hr. For No. 2 fuel oil, the nitrogen oxides emission level should be 0.20 lb/MM Btu, and the correct hourly rate is 50.0 lb/hr for a heat input rate of 250 MM Btu/hr.

X. The Sulfur Dioxide emission level should be 0.17 lb/MM Btu rather than 0.16 lb/MMBtu because the level proposed was 0.167 lb/MMBtu, which should be rounded to 0.17 lb/MMBtu rather than 0.16 lb/MMBtu. The correct hourly level for sulfur dioxide then becomes 125 lb/hr. For a sulfur dioxide emission level of 0.05 lb/MMBtu for No. 2 fuel oil, the correct hourly rate is 12.5 lb/hr for a heat input rate of 250 MM Btu/hr.

Y. The sulfuric acid mist emission level for bagasse should be 0.017 lb/MM Btu rather than 0.016 lb/MMBtu because the level proposed was 0.0167 lb/MMBtu, which should be rounded to 0.017 lb/MMBtu rather than 0.016 lb/MMBtu. The correct hourly level for sulfuric acid mist then becomes 13 lb/hr while burning bagasse. The sulfuric acid mist emission level should be 0.005 lb/MMBtu for No. 2 fuel oil, and the hourly rate is 1.25 lb/hr for a heat input rate of 250 MM Btu/hr.

Z. For VOC the hourly emission limit for 0.21 lb/MM Btu should be 157 lb/hr. The emission level should be 0.004 lb/MM Btu for No. 2 fuel oil, and the hourly rate for oil is 1.0 lb/hr for a heat input rate of 250 MM Btu/hr.

Carbon monoxide should be deleted from the table because no BACT analysis is required for CO. Otherwise, a carbon monoxide emission level of 0.70 lb/MM Btu while burning bagasse, the hourly limit would be 516 lb/hr. The CO limit is 0.066 lb/MM Btu for No. 2 fuel oil, and the hourly rate should be 16.5 lb/hr for a heat input rate of 250 MM Btu/hr.

The reference to PM/PM_{10} should be deleted because Boiler No. 7 is not subject to an analysis requirement for particulate matter.

Finally, there appears to be no need to establish specific emission limits for sulfuric acid mist or beryllium since these will be controlled by the content of the No. 2 fuel oil, which must meet specifications in any event.

Details of the Analysis May be Obtained by Contacting:
Mr. John Brown, P.E. Administrator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
Date	Date

COMMENTS ON THE DRAFT AIR CONSTRUCTION PERMIT CONDITIONS FOR CLEWISTON BOILER NO. 7

September 9, 1994

P.O. Box 1207
Clewiston, Florida 33440

County: Hendry
Latitude/Longitude: 26°44'05"N 80°56'20"W
Project: Boiler No. 7

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2.297,17-4 and 40 CFR 52.21. The above named permittee is hereby authorized to perform the work or operate the facility show on the application and approved drawings, plans and other documents attached hereto or on file with the department and made apart hereof and specifically described as follows:

Construction of 738 million BTU/hr heat input (350,000 lb/hr steam) boiler designed to burn bagasse and ~~diesel~~ **No. 2** fuel oil ~~No. 2~~. The consumption of oil shall not exceed 10% of the **maximum potential** ~~total~~ heat input to the boiler in any calendar year. Boiler No. 7 will be installed at U.S. Sugar Corporation's existing sugar mill that is located near the intersection of W. C. Owens Avenue and Clewiston Street in Clewiston, Hendry County, Florida. The UTM coordinates of this site are 17-506.1 Km E and 2956.9 KmN.

COMMENTS:

0.1 The term "No. 2 fuel oil" should be used consistently throughout the permit and BACT determination to refer to the fuel oil that will be burned as the supplemental fuel in this boiler. "Diesel" should not be used to refer to this fuel because that term is commonly used to refer to motor fuels that contain dyes and other additives that would be inappropriate for use in this boiler and could unnecessarily increase the cost of this fuel.

0.2 Insert the word "potential" before "heat input" because the correct criterion under 40 C.F.R. §§ 60.44b(j)(2) and 60.41b is that consumption of oil shall not exceed 10% of the annual capacity factor, which assumes operation at maximum potential capacity.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Application received September 17, 199**3**~~2~~.
2. DEP letter dated October 15, 1993.
3. **U.S. Sugar letter dated December 22, 1993.**
4. **U.S. Sugar letter dated February 22, 1994.**
5. **DEP letter dated February 28, 1994.**
6. **DEP letter dated March 18, 1994.**
7. **U.S. Sugar letter dated May 10, 1994.**
8. U.S. Sugar letter dated June **7** ~~3~~, 1994.
9. U.S. Sugar letter dated June **27** ~~29~~, 1994.
10. U.S. Sugar letter dated July 13, 1994.
11. U.S. Sugar letter dated July 28, 1994.

SPECIFIC CONDITIONS:

EMISSION LIMITATIONS

1. Based on a maximum heat input to the boiler of 738 MM Btu/hr for bagasse and **250** MM Btu/hr for fuel oil, stack emissions shall not exceed the following limits:

ALLOWABLE EMISSIONS

Pollutant	Bagasse			No. 2 Fuel Oil		
	1b/MMBtu	1b/hr	ton/yr	1b/MMBtu	lb/hr	ton/yr
Particulate (PM/PM_{10})	**0.04**	**30**	**129**	**0.04**	**10**	**12.88**
Sulfur Dioxide[1]	**0.17**	**125**	**550**	**0.05**	**12.5**	**16.10**
Nitrogen Oxides[2]	**0.26**	192	**840**	**0.2**	**50.0**	**64.40**
Carbon Monoxide	**0.70**	**516**	**2,262**	0.066	**16.5**	**21.25**
Volatile Organic Compounds	0.212	157	689	0.004	**1.0**	**1.29**
~~Sulfuric Acid Mist~~	~~0.017~~	~~13~~	~~55~~	~~0.005~~		
~~Lead~~				~~56E-06~~		
~~Mercury~~				~~6.4E-06~~		
~~Beryllium~~				~~8.4E-06~~		
~~Fluorides~~				~~12.6E-06~~		

Notes:

[1] ~~**Compliance based on use of very-low-sulfur fuel oil (0.05% sulfur) and on 24-hour rolling average per 40 CFR 60, Subpart Db.**~~

[2] ~~**Compliance based on use of low-nitrogen fuel oil and on 24-hour rolling average per 40 CFR 60, Subpart Db.**~~

COMMENTS:

1.1 Change the heat input value for No. 2 fuel oil to 250 MM Btu/hr because U.S. Sugar has decided to accept this limitation under 40 C.F.R. § 60.44b(k) to avoid the applicability of the emission standard requirements of 40 C.F.R. § 60.44b while burning No. 2 fuel oil. BACT under these circumstances is the burning of low nitrogen fuel, and U.S. Sugar proposes to accept an emission limit of 0.2 lb/MM Btu for nitrogen oxides while burning No. 2 fuel oil to reflect this BACT.

1.2 Change the reference to fuel oil to read "No. 2 fuel oil."

1.3 Change the emission level for Particulate to 0.04 MM Btu/hr because this is the level that U.S. Sugar proposes to reflect the control level that can be achieved through the use of an ESP, and that level of control results in a net increase in emissions less than the significant level necessary to trigger a PSD analysis requirement.

1.4 The proper hourly emission value for Particulate at 0.04 lb/MM Btu with a heat input of 738 MM Btu/hr is 30 lb/hr.

1.5 The proper annual emissions for Particulate is 129 tons per year assuming 30 lb/hr and operation for 8760 hrs per year.

1.6 The Particulate limit for No. 2 fuel oil is also 0.04 lb/MM Btu.

1.7 The hourly emission level for Particulate is 10 lb/hr assuming a heat input level of 250 MM Btu/hr and a limit of 0.04 lb/MM Btu.

1.8 The annual Particulate emission level for No. 2 fuel oil is 12.88 tons per year assuming maximum fuel oil combustion under the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The heating value for No. fuel oil is assumed to be 140,000 Btu/gal.

1.9 The Sulfur Dioxide emission level should be 0.17 lb/MM Btu rather than 0.16 lb/MMBtu because the level proposed was 0.167 lb/MMBtu, which rounds to 0.17 lb/MMBtu rather than 0.16 lb/MMBtu.

1.10 The correct hourly level for sulfur dioxide then becomes 125 lb/hr, and the correct annual level is 549.5 tons/yr.

1.11 For a sulfur dioxide emission level of 0.05 lb/MMBtu for No. 2 fuel oil, the correct hourly rate is 12.5 lb/hr for a heat input rate of 250 MM Btu/hr.

1.12 The annual emission level for sulfur dioxide is 16.10 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The heating value for No. 2 fuel oil is assumed to be 140,000 Btu/gal.

1.13 For nitrogen oxides, the demonstrated BACT emission level is 0.26 lb/MM Btu as presented in the U.S. Sugar analysis submitted on June 27, 1994. The grounds supporting adoption of this level are presented in the comments on the draft BACT analysis.

1.14 Based on an emission rate of 0.26 lb/MM Btu, the hourly level for nitrogen oxides should be 192 lb/hr, and the annual level should be 840 ton/yr.

1.15 For No. 2 fuel oil, the nitrogen oxides emission level should be set at 0.20 lb/MM Btu. Since the heat input rate will remain at or below 250 MM Btu/hr while the boiler is burning No. 2 fuel oil, no emission limit is dictated for nitrogen oxides by the new source performance standard (NSPS) in 40 C.F.R. Part 60 Db. Accordingly, it is appropriate to set an emission level of 0.20 lb/MM Btu to reflect the emission level that will be achieved through the use of No. 2 fuel oil.

1.16 For a nitrogen oxides emission level of 0.20 lb/MMBtu for No. 2 fuel oil, the correct hourly rate is 50.0 lb/hr for a heat input rate of 250 MM Btu/hr.

1.17 The annual emission level for nitrogen oxides while burning No. 2 fuel oil is 64.40 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The heating value for No. fuel oil is assumed to be 140,000 Btu/gal.

1.18 For carbon monoxide emissions during bagasse burning, U.S. Sugar has opted to use a level of 0.70 lb/MM Btu to reflect the level that will be achieved from good combustion practices. This level still results in a substantial reduction from the emission levels for Boilers Nos. 5 and 6. Therefore, no BACT requirement applies. For an emission level of 0.70 lb/MM Btu, the hourly rate is 516 lb/hr, and the annual rate is 2,232 tons/yr.

1.19 For a carbon monoxide emission level of 0.066 lb/MM Btu for No. 2 fuel oil, the correct hourly rate is 16.5 lb/hr for a heat input rate of 250 MM Btu/hr. The annual emission level for carbon monoxide while burning No. 2 fuel oil is 21.25 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The heating value for No. fuel oil is assumed to be 140,000 Btu/gal.

1.20 For a volatile organic compound (VOC) emission level of 0.004 lb/MM Btu for No. 2 fuel oil, the correct hourly rate is 1.0 lb/hr for a heat input rate of 250 MM Btu/hr.

1.21 The annual VOC emission level while burning No. 2 fuel oil is 1.29 ton/yr assuming maximum fuel oil combustion under the 10% annual capacity factor, which yields a limit of approximately 4.6 million gallons per year. The heating value for No. fuel oil is assumed to be 140,000 Btu/gal.

1.22 The sulfuric acid mist emission level should be deleted from the permit because these emissions will be controlled primarily through the content of the No. 2 fuel oil, which is controlled through specification and certification. It makes little sense to list a limit when compliance will be met through the fuel monitoring process. Otherwise, the emission level should be 0.017 lb/MM Btu rather than 0.016 lb/MMBtu because the level proposed was 0.0167 lb/MMBtu, which should be rounded to 0.017 lb/MMBtu rather than 0.016 lb/MMBtu.

1.23 The correct hourly level for sulfuric acid mist should be dropped from the permit. If listed, the level would be 13 lb/hr, and the correct annual level is 55 tons/yr.

1.24 For a sulfuric acid mist emission levels should not be specified in the permit.

1.25 The annual emission level for sulfuric acid mist should not be listed.

1.26 Note 1 should be deleted because the NSPS requirement for a 24-hour rolling average under 40 C.F.R. § 60.42b(f) does not apply to this boiler pursuant to 40 C.F.R. § 60.42b(j)(2), for this boiler will burn only "very low sulfur oil" and will demonstrate that the oil meets the definition of "very low sulfur oil" by maintaining fuel receipts as described in 40 C.F.R. § 60.49b(r). Therefore, there is no requirement for a 24-hour rolling average emission level or for conducting an annual compliance test for sulfur dioxide.

1.27 Note 2 should be deleted because the NSPS requirement for a 24-hour rolling average standard does not apply, for this boiler will meet the requirements of both 40 C.F.R. § 40.44b(j)(1),(2), and (3), as well as the requirements of § 40.44b(k). Therefore, there is no requirement for a 24-hour rolling average emission level or for conducting an annual compliance test for nitrogen oxides.

1.28 The remaining pollutants should be dropped from the permit since these levels will be controlled exclusively by the content of the No. 2 fuel oil, which is regulated through the specification and certification process.

CONSTRUCTION AND OPERATIONAL REQUIREMENTS

2. Construction of the proposed Boiler No. 7 shall reasonably conform to the plans described in the application.

NO COMMENT

3. The boiler shall be of the spreader-stoker, vibrating-grate type.

NO COMMENT

4. The Boiler No. 7 stack shall have a minimum height of 225 feet. <u>**After Boiler No. 7 becomes operational, the**</u> Boiler No. 1, 2, and 3 stacks shall have a minimum height of 150 feet. The stack sampling facilities for each stack shall comply with F.A.C. Rule 17-297.345.

COMMENT:

4.1 The permit should make clear that the requirement for increased stack height becomes effective only when Boiler No. 7 becomes operational.

5. The boiler shall be equipped with instruments to measure fuel oil flowrate, steam production, steam pressure, and steam temperature.

NO COMMENT

6. This boiler shall be equipped with an electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

The permittee shall submit to the Department copies of technical data pertaining to the selected electrostatic precipitator and to the boiler design within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rate and major design parameters.

Nitrogen oxides emissions will be controlled by overfire air and good combustion practices. Carbon <u>**monoxide**</u> ~~dioxide~~ and volatile organic emissions will be controlled by good combustion practices. Sulfur dioxide and sulfuric acid emissions, when firing fuel oil will be controlled by using <u>**very**</u> low sulfur ~~diesel~~ <u>**No. 2**</u> fuel oil ~~No. 2~~ (0.05% S).

COMMENTS:

6.1 Proper reference should be to very low sulfur No. 2 fuel oil. (See also Comment 0.1, above.)

~~[7. The permittee shall install and operate continuous monitoring devices for this boiler exhaust for opacity, nitrogen oxides (NO_x), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO). The monitoring devices shall meet the applicable requirements of Section 17-297.500, F.A.C., and 40 CFR 60 Subpart Db. The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the stock or in the stack.]~~

COMMENTS:

7.1 Because Boiler No. 7 will combust only bagasse or very low sulfur oil, under 40 C.F.R. § 60.47b(f) the boiler is not subject to emission monitoring requirements -- especially not continuous emission monitoring (CEM) requirements -- since U.S. Sugar will obtain fuel receipts as described in § 60.49b(r).

7.2 Boiler No. 7 is not subject to continuous emission monitoring requirements under Section 17-297.500, F.A.C. either because Boiler No. 7 will not be a fossil fuel steam generator unit within the meaning of that section. This boiler will burn bagasse and use No. 2 fuel oil only as a supplementary fuel; while burning oil will have a heat input level that does not exceed 250 MM Btu/hr; and will have an annual capacity factor that does not exceed 10% while burning No. 2 fuel oil.

7.3 Even if the boiler were subject to CEM requirements, there would not be a requirement to monitor for both oxygen and carbon dioxide -- only one or the other.

7.4 Under 40 C.F.R. § 60.48b(i), there is no requirement to install or operate a continuous monitoring system for monitoring nitrogen oxides emissions because the boiler will meet the criteria of both § 60.44b(j) and § 60.44b(k), and meeting the criteria of either one or the other is sufficient to exempt the boiler from the nitrogen oxides standards of 40 C.F.R. § 60.44b as well as any CEM requirement for nitrogen oxides.

7.5 In light of the infrequency with which Boiler No. 7 will be burning No. 2 fuel oil and in light of the low ash content of No. 2 fuel oil emissions, U.S. Sugar requests pursuant to 40 C.F.R. § 60.13(i) the establishment and approval of an alternative monitoring requirement for opacity -- namely, a requirement that a video camera be installed and focused on the stack for Boiler No. 7 and that the camera be operated when No. 2 fuel oil is burned in the boiler.

8. Boiler No. 7 ~~The proposed steam generating unit~~ shall be operated in accordance with the capabilities and specifications described in the application. ~~Boiler No. 7~~ Steam production, ~~steam pressure, steam temperature,~~ heat input, and bagasse **consumption** ~~feedrate~~ shall not exceed the following:

Steam Press., psig	Steam Temp., F°	Averaging Time~~1~~	Steam Production, 1b/hr	Heat Input, MM Btu/hr	Bagasse Feedrate lbs/hr-wet
600	750	1-hr. max. 24-hr. avg.	385,000 350,000	812 738	203,060 184,600

~~1 Maximum is a one (1) hour average.~~

COMMENTS:

8.1 The language of this specific condition should be clarified to refer specifically to Boiler No. 7 and revised to narrow the limitations to apply only to the steam production, heat input, and bagasse consumption, as was recently done on the operating permit for Bryant Boiler No. 5 (AO 50-234931). There is no need to limit the steam pressure and steam temperature to accomplish the objectives of this provision.

8.2 Likewise, the averaging times should be restated to coincide with the 1-hour and 24-hour time periods used in the Bryant Boiler No. 5 permit. The 6-hour time period is not very practical because it does not coincide with the 8-hour shift length at the mill.

9. Heat input from No. 2 fuel oil (0.05%S) shall not exceed 250 ~~4~~MMBtu/hr (which is approximately equivalent to 1,785 gallons per hour of oil and 175,000 pounds per hour of steam). The boiler shall be operated so that not more than two burners with two oil guns each (total of four oil guns) can be used with a total maximum capacity not to exceed the permitted oil input.

COMMENTS:

9.1 The heat input rate should be changed to 250 MM Btu/hr in accordance with U.S. Sugar's agreement to accept this limit in lieu of application of an NSPS emission limit for nitrogen oxides.

9.2 The correct approximation of fuel consumption to coincide with the heat input level of 250 MM Btu/hr is 1,785 gallons per hour, assuming a heating value of 140,000 Btu/gal for No. 2 fuel oil.

10. During any **calendar year** ~~12-month period~~, the maximum quantity of No. 2 fuel oil (with a 0.05% S) burned in Boiler No. 7 shall not exceed **4,600,000** ~~3,000,000~~ gallons. The

consumption of oil shall not exceed 10% of the ~~total~~ **maximum potential** heat input to the boiler in any calendar year.

COMMENTS:

10.1 The term "12-month period" should be changed to "calendar year" because the annual capacity factor under 40 C.F.R. § 40.41b is determined on a calendar year basis.

10.2 For Boiler No. 7, the annual capacity factor of 10% is equal to 10% of the potential heat input to the boiler at 738 MM Btu/hr for bagasse assuming operation for 8,760 hours during a calendar year. Multiplying 738 MM Btu/hr by 8,760 hours per year, taking 10% and dividing by 140,000 Btu/gal for No. 2 fuel oil, yields a result of 4,617,771 gallons per year as the No. 2 fuel oil consumption limitation. U.S. Sugar proposes to round this limit off at 4,600,000 gallons per year.

10.3 The term "maximum potential" should be inserted to be consistent with the definition of "annual capacity factor" in 40 C.F.R. § 60.41b. These determinations are made on the basis of the maximum "potential heat input to the steam generating unit."

~~11. During any 24-hour period, not more than 40,800 gallons of fuel oil shall be burned in all stationary fuel-oil burning equipment at the plant. All permits to operate other oil-burning equipment at this plant are revised to include this limitation.~~

~~12. During any 3-hour period, not more than 6,300 gallons of fuel oil shall be burned in all stationary fuel-oil burning equipment at the plant. Excess fuel oil burning resulting from start-up, shutdown, or malfunction of any source shall be permitted, provided that best operational practices to minimize emissions are adhered to and that the duration of excess emissions shall be minimized. All permits to operate other oil-burning equipment at this plant are revised to include this limitation.~~

COMMENTS:

11.1 Draft specific conditions 11 and 12 should be deleted because they refer only to the combustion of No. 6 fuel oil, the supplemental fuel originally proposed for Boiler No. 7. Since U.S. Sugar has agreed to burn No. 2 fuel oil with a heat input limit of 250 MM Btu/hr instead, the emission rates for fuel oil combustion will be lower than those for bagasse combustion. Accordingly, these limits are no longer appropriate for inclusion in this permit.

11.2 In addition, the permits for Clewiston Boiler No. 4 that are currently under revision by the Department should be revised

to make these limitation provisions, as included in those permits, applicable exclusively to the burning of No. 6 fuel oil.

13. All stationary fuel-oil burning equipment at the plant shall be equipped with integrating fuel oil flow meters or continuous recorders to measure the amount of fuel oil consumed by the equipment. Oil meter readings on all oil-consuming equipment shall be read and logged at least once every three hours, unless oil consumption for the equipment is recorded continuously, and these records shall be kept for at least five years for Department inspection. Each meter shall be calibrated annually by a method approved by the Department.

NO COMMENT

~~**14. The permittee shall maintain a daily log of fuel oil amount, heating value, and equivalent SO_2 emission rate (in lb/MmBtu). The SO_2 emission rate shall be determined from the sulfur content of the fuel oil, based on certified analysis from the fuel oil vendor. These daily logs shall be kept for at least two years.**~~

COMMENTS:

14.1 This specific condition should be deleted. The provision relates to the mixing of fuel oils having different percentages of sulfur content and was considered in the original application because U.S. Sugar proposed at that time to use a single storage tank of No. 6 fuel oil to supply all of the boilers at the Clewiston Mill and to simply replenish the quantity of fuel burned in Boiler No. 7 with new quantities of No. 6 fuel oil having a sulfur content of 0.5% or less. Now that U.S. Sugar has agreed to burn No. 2 fuel oil in Boiler No. 7, this provision is no longer necessary or appropriate, especially since draft specific condition 22 will accomplish the legitimate objective of ensuring compliance with section 60.49b(r) of the applicable NSPS.

15. **Boilers No. 5 and 6 may be retained as standby boilers at the Clewiston Mill. Boilers No. 5 and 6 may be operated during initial start-up, debugging, and testing of Boiler No. 7. After Boiler No. 7 becomes operational, Boilers No. 5 and 6 may be operated only when one or more of the other boilers at Clewiston Mill are shut down.** ~~**During Boiler No. 7 operation, the existing Boilers No. 5 and 6 shall be shut down. Boilers No. 5 and 6 may be operated only when Boiler No. 7 is not operating.**~~ During operation, Boilers No. 5 and 6 must meet all requirements in their current operating permits.

COMMENTS:

15.1 The proposed substitute language clarifies the operational status of Boilers No. 5 and 6.

16. Prior to operation of the source, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

NO COMMENT

COMPLIANCE REQUIREMENTS and annually thereafter

17. Performance Stack Tests. Within 60 calendar days after achieving the maximum capacity at which this unit will be operated, but no later than 180 operating days after initial start-up, the permittee shall conduct performance tests for ~~all pollutants listed in specific Condition No. 1~~ **particulates, nitrogen oxides, carbon monoxide, and volatile organic compounds while burning bagasse**. The performance tests shall be conducted in accordance with the provisions of 40 CFR 60.45b and 60.46b. Testing of emissions shall be conducted with the source operating **within 90-100% of the maximum heat input rate of 812 MM Btu/hr.** ~~at permitted capacity. Permitted capacity is defined as 90-100% of the maximum operating rate allowed by the permit.~~ If it is impracticable to test at permitted capacity, then **Boiler No. 7** ~~sources~~ may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once **Boiler No. 7** ~~the unit~~ is so limited, then operation at higher capacities is allowed for no more than **twenty-five calendar days** ~~fifteen consecutive days~~ for the purposes of additional compliance testing to regain the permitted capacity in the permit~~, with prior notification to the DEP South District office~~. Results of the tests shall be submitted to the Department within 45 days after testing. The South Florida District office shall be notified 30 days prior to any compliance test to allow witnessing.

Compliance with **these** emission limitations ~~stated in Condition No. 1~~ shall be demonstrated **as required** using EPA Methods, as 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) , or any other method as approved by the Department, in accordance with F.A.C. Chapter 17-297. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

COMMENTS:

17.1 The compliance testing requirement should be limited to operation while burning bagasse because Boiler No. 7 will rarely be operated with No. 2 fuel oil. The boiler is not subject to NSPS testing requirements for these pollutants while burning No. 2 fuel oil.

17.2 Testing should be required only for the listed pollutants and not for sulfur dioxide or sulfuric acid mist because the control method for these pollutants is the burning of very low sulfur No. 2 fuel oil, for which the critical factor is the sulfur content of the fuel oil.

17.3 The permitted maximum heat input rate should be specified for clarification purposes.

17.4 The specific references to Boiler No. 7 should be substituted for clarification purposes.

17.5 U.S. Sugar has previously reached agreement with the Department that 25 calendar days is a more appropriate allowance for bringing a bagasse boiler up to maximum capacity in light of the normal operational factors affecting these boilers. This allowance was recently included in the renewal of the permit for Bryant Boiler No. 5 and should be adopted here as well.

17.6 The notification requirement for operation is unnecessary in light of the requirement that the South District be notified 30 days prior to any compliance test.

17.7 The phrase "as required" should be included to clarify that this paragraph is not intended as an independent compliance test requirement. It is only intended to specify that any testing that is required in the previous paragraph be conducted in accordance with the specified methods.

18. Particulate matter (PM/PM_{10}) emissions from Boiler No. 7 shall not exceed **0.04** ~~0.03~~ lb/million Btu heat input for bagasse fuel or **0.04** ~~0.10~~ lb/million Btu heat input for **No. 2** fuel oil ~~No. 2~~. In event that both fuels are burned concurrently, the allowable particulate matter emissions shall be prorated from the allowable standards for each fuel by their respective heat inputs. Compliance with the particulate matter standards shall be determined by EPA Reference Methods 1, 2, 3, 4, **and** 5 ~~and 201 or 201A~~ as described in 40 CFR 60, Appendix A. The compliance test results shall be calculated by assuming the thermal efficiency of Boiler No. 7 is 55%, or any new method subsequently adopted by Department rule. For information purposes only, the particulate matter emission rate shall also be calculated by utilizing the short-form ASME boiler-efficiency test results (once every five years).

COMMENTS:

18.1 The particulate emission rates for bagasse and No. 2 fuel oil should be revised to coincide with the 0.04 lb/MM Btu rates included in Specific Condition No. 1.

18.2 The PM10 testing requirement should be dropped as redundant; testing with Method 5 will suffice because compliance under Method 5 will, by definition mean compliance with PM10 testing.

19. Unconfined Particulate Matter during land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seedings and mulching of disturbed areas, shall be undertaken and implemented. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations. ~~**All conveyor and conveyor transfer points shall be enclosed to preclude PM emissions.**~~

COMMENTS:

19.1 This sentence should be moved to Specific Condition No. 21 because it relates to bagasse handling systems, and it should be revised as noted in the comments on that specific condition.

20. Visible emissions from Boiler No. 7 shall not exceed 20% opacity except that 27% opacity is allowed for 6 minutes during any one (1) hour period. Compliance with the standard shall be determined by Reference Method 9 as described in Chapter 17-297, F.A.C. The particulate matter emissions and visible emissions shall be determined concurrently. Under circumstances when this is not feasible, the company shall obtain ~~**prior**~~ approval from the South Florida District to conduct the tests at separate times. In such circumstances, the tests shall be conducted as close to each other as is feasible.

COMMENTS:

20.1 A requirement for approval should be sufficient and should include an allowance for obtaining contemporaneous or after-the-fact approval. It is not always feasible to obtain prior approval.

21. Visible emissions from the bagasse handling systems shall not exceed 10% opacity over any 6 minute period as measured by EPA Reference Method 9, provided, however, that this visible emissions limit shall not apply during periods of high winds (wind speed of **12** ~~**18**~~ miles per hour or greater) if reasonable precautions (covered conveyors, windbreaks, and minimum drop-point height) to control fugitive emissions have been taken. **Reasonable precautions** ~~**Water spray or other effective means**~~ will

be used to minimize fugitive emissions when reclaiming dry bagasse for the boiler. The permittee shall maintain a meteorological instrument to record the wind speed at the plant which shall be located at its Research Center, about one mile "south" of the Clewiston mill.

COMMENTS:

21.1 The wind speed for high winds should be changed to 12 miles per hour. Experience has shown that bagasse has the potential to become airborne at wind speeds of 12-14 miles per hour.

21.2 Water spray should not be dictated for reclaiming of bagasse because the addition of water will lower the combustibility of the bagasse and increase potential to generate pollutants associated with incomplete combustion. A requirement for "reasonable precautions" should be substituted.

22. <u>No. 2 fuel oil</u> ~~Diesel fuel oil No. 2~~ burned in this boiler shall contain no more than 0.05% sulfur. Compliance with this condition shall be determined from certified analyses of the oil by ASTM Method D-129, D-1552, D-2622 or D-4294 by the fuel supplier or the permittee. Records of the quantity and analysis of fuel oil consumed in Boiler No. 7 and invoices for the oil purchases shall be kept for a minimum of five years for regulatory agency inspection.

COMMENTS:

22.1 The reference to "diesel" should be dropped for the reasons stated previously, and the consistent use of "No. 2 fuel oil" should be maintained.

23 . <u>Sulfur dioxide emissions</u> from Boiler No. 7 while it is burning 100% bagasse fuel, shall not exceed **<u>0.17</u>** ~~0.16~~ lb/million Btu ~~heat input as determined by EPA Reference Method 6 as described in 40 CFR 60, Appendix A. The compliance test results shall be calculated by assuming the thermal efficiency of Boiler No. 7 is 55%, or any new method subsequently adopted by Department rule~~. The department will re-evaluate this sulfur dioxide standard, without penalty to the applicant, if technical data is submitted to the Department ~~prior to the expiration of this permit~~ that confirms that emissions from bagasse are different under the two operation modes (bagasse only versus bagasse/oil combination) . ~~For informational purposes only, the sulfur dioxide emission rate shall also be calculated by utilizing the short-form ASME boiler-efficiency tests results (once every five years).~~

COMMENTS:

23.1 The compliance testing requirement for sulfur oxides should be eliminated completely because the control of sulfur oxides emissions is achieved exclusively through the combustion of very low sulfur No. 2 fuel oil. There is no applicable NSPS requirement for testing.

23.2 The emission level for sulfur oxides should be revised to agree with the level used in Specific Condition No. 1.

24. Nitrogen oxides emissions. expressed as NO_2, shall not exceed **192** ~~148~~ lb/hr as determined by EPA Reference Method 7 **or Method 7E** described in 40 CFR 60, Appendix A.

COMMENTS:

24.1 The reference to Method 7E should be included to be consistent with established Department policy and other permits issued to U.S. Sugar and others. EPA Method 7E is approved for this use under F.A.C. Chapter 62-297 of the Department's regulations.

24.2 The hourly emission limit for nitrogen oxides should be 192 lb/hr.

~~25. The permittee shall provide enough space for the future installation, if deemed necessary by the Department, of a SNCR.~~

COMMENTS:

25.1 Draft Specific Condition No. 25 should be deleted because there is no applicable requirement or authority for this provision, and it is unnecessary.

26. Carbon monoxide and volatile organic compounds emissions shall be maintained at the lowest possible level through the implementation of an Operation and Maintenance plan that is approved by the Department. Emissions of carbon monoxide shall not exceed **0.70** ~~0.35~~ lb/million Btu as determined by EPA Method 10. Emissions of **nonmethane** volatile organic compounds shall not exceed 1.7 lb/ton of wet bagasse or 0.212 lb/MMBtu as determined by EPA Method 25 **or by EPA Method 25A in conjunction with EPA Method 18**. These test methods are described in 40 CFR 60, Appendix A.

COMMENTS:

26.1 The carbon monoxide emission limit should be changed to 0.70 lb/MM Btu.

26.2 The reference to testing methods should be expanded to include the use of Method 25A in conjunction with Method 18 to determine nonmethane VOCs for the reasons explained in our submission on RACT requirements for Bryant Boilers Nos. 1-3 (Attachment A to these Comments).

26.3 The VOC emission level here should be consistent with that stated in Specific Condition No. 1.

27. Thermal efficiency. A test shall be made on Boiler No. 7 to determine its actual thermal efficiency in accordance with the ASME short-form procedure each time the operating permit for this boiler is renewed. The test shall be done while the tubes are clean and within 14 days of the compliance test **unless an alternative schedule is approved by the Department.**. A current report on the thermal efficiency tests must be included with the application to operate this boiler.

NO COMMENT

REPORTING REQUIREMENTS

28. Fuel usage, fuel analysis data, and sulfur dioxide emissions calculations for fuel oil combustion shall be reported to the Department's South District Office on a **quarterly** ~~annual~~ basis commencing with the start of full-time operation in accordance with 40 CFR, Part 60, Sections 60.7 and 60.49b.

COMMENTS:

28.1 The reporting period should be changed from annual to quarterly to satisfy the applicable NSPS requirement in 40 C.F.R. § 60.49b(r).

29. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

NO COMMENT

30. An application for an operation permit must be submitted to the South District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance tests reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

NO COMMENT

~~**RULE REQUIREMENTS**~~

~~**This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapter 17-4 and Chapters 17-209 through 297, Florida Administrative Code (F.A.C.), 40 CFR 60; and applicable requirements of 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.**~~

COMMENTS:

X.1 This provision should be deleted as both unnecessary and unauthorized. These issues can be addressed in conjunction with Title V permitting that will be required for the Clewiston Mill and will involve all of the boilers at the mill. There is no reason to delay the issuance of this permit to address these issues prematurely before the commencement of the Title V permit process.

Issued this __________ day
of ____________________, 1993 4

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

____
Virginia B. Wetherell, Secretary
Department of Environmental
Protection

KBN

September 8, 1994

RECEIVED

Bureau of
Air Regulation

Mr. Cleveland Holladay
Bureau of Air Management
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: U.S. Sugar Corp. - Clewiston Mill Boiler No. 4, Permit AO26-223258

Dear Cleve:

Please find enclosed one hard and disk copy of the ISCST2 CO analysis model printout associated with the above referenced permit. Disk output files are compressed within an archive file using the utility PKZIP. The unarchiving utility program PKUNZIP is included on the disks. Should you have any questions relating to the printouts please call me at (904) 331-9000. Thank you.

Sincerely,

Steven R. Marks

Steven R. Marks
Senior Meteorologist

SRM/mk

cc: David Buff, KBN
File (2)

RECEIVED

SEP 8 1994

Bureau of
Air Regulation

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SEP 9 1994

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Air Regulation

KBN ENGINEERING AND APPLIED SCIENCES, INC.

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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Teresa:
2.
3.
4.

The report looks incomplete. They need to furnish information required pursuant to 62-297.570(3) i, j, k, l, m, n, o, p, q, r, s, u. We will continue our review once we receive the above requested info.

Thanks,

Ramesh

FROM:

Teresa -
the tests probably should go thru MIC.
Thanks
[signature]

NE

08-18-93

BEST AVAILABLE COPY

UNITED STATES SUGAR CORPORATION

Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121 Telex: 510-952-7753

August 9, 1994

RECEIVED
Bureau of Air Regulation

Ms. Theresa M. Heron, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl. 32399-2400

Subject: U. S. Sugar Corporation, Clewiston Mill
Boiler No. 7 - PSD Permit Application

Dear Ms. Heron:

Enclosed is the final report for the United McGill dry and wet electrostatic precipitator tests carried out at the Clewiston mill.

If you have any questions or require additional information, please contact me.

Sincerely,

UNITED STATES SUGAR CORPORATION

Donald Griffin

DG:jt
Enclosures

cc: Mr. John C. Brown

BRYAN CAVE

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NEW YORK, NEW YORK
PHOENIX, ARIZONA
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FRANKFURT AM MAIN, GERMANY

ROBERT F. VAN VOORHEES
DIRECT DIAL NUMBER
(202) 508-6014

File

RECEIVED
JUL 29 1994
Bureau of
Air Regulation

July 28, 1994

Teresa M. Heron, P.E.
Florida Department of
Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, FL 32399-2400

Re: United States Sugar, Clewiston Boiler No. 7
PSD Permit Application

Dear Ms. Heron:

Enclosed are six copies of revised Tables 2-3, 2-4, and 2-5. These tables provide the information that you requested regarding equivalent values -- expressed as pounds per day and tons per year -- for the proposed criteria pollutant emission limits presented in the revised Table 2-8 provided as Attachment C to Murray Brinson's letter dated June 27, 1994.

Since the highest emission rates in each case are associated with bagasse combustion and since bagasse is the preferred fuel, the hourly, daily and annual maximum emission levels are derived on the assumption that bagasse will be the only fuel used. The values presented in Table 2-4 and 2-5 for Boiler No. 7 represent the product of the bagasse firing rate of 738 MMBtu/hr and the emission rates presented in Table 2-8.

The values presented in Table 2-3 as annual emissions for Boiler No. 7 are derived by multiplying the hourly rates from Tables 2-4 and 2-5 by 8760 hours per year to get pounds per year emissions and then dividing by 2,000 to convert to a tons per year value.

This should provide you with all of the information that you requested when we spoke this week.

In addition, this will serve to confirm our discussion of the stack height increases to 150 feet for Clewiston Boilers Nos. 1, 2, and 3 as proposed in the application. We now understand that these increases will be addressed and authorized in a specific condition of the Clewiston Boiler No. 7 permit rather than in separate permit revisions for those boilers.

Please call me if you need any additional information.

Sincerely,

Robert F. Van Voorhees

Robert F. Van Voorhees

Enclosures

cc: Murray Brinson
Peter Briggs
Peter Kroll
C. Holladay
D. Knowles, SF Dist.
J. Harper, EPA
J. Bunyak, NPS

82631.01

BRYAN CAVE

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ROBERT F. VAN VOORHEES
DIRECT DIAL NUMBER
(202) 508-6014

July 13, 1994

RECEIVED
JUL 13 199
Bureau of Air Regulation

Teresa M. Heron, P.E.
Florida Department of
Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, FL 32399-2400

Re: United States Sugar, Clewiston Boiler No. 7
PSD Permit Application

Dear Teresa:

Enclosed are six additional copies of Tables 5-7 and 5-8 with the proper page numbers. These are probably missing from the copies sent to John Brown, Preston Lewis, Doug Outlaw, Cleve Holladay and William Congdon.

We are preparing the additional information you requested regarding hourly and annual emission levels. Please call me if you need any additional information.

Sincerely,

Bob

Robert F. Van Voorhees

Enclosures

82278.01

cc: T. Heron
C. Holladay
D. Knowles, SF Dist
G. Harper, EPA
J. Bunyak, NPS

copy 7/11/94
P. Dee
D. Buff
P. Briggs
R. Van Fleet
P. Kroll

United States Department of the Interior

NATIONAL PARK SERVICE
Southeast Regional Office
75 Spring Street, S.W.
Atlanta, Georgia 30303

IN REPLY REFER TO:
N16(SER-ODN)

JUL 1994
RECEIVED
Clewiston Sugar House

JUN 28 1994

RECEIVED
JUL 06 1994
Bureau of
Air Regulation

Mr. Clair Fancy
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

We have reviewed the Prevention of Significant Deterioration permit application for U.S. Sugar Corporation's (U.S. Sugar) sugar mill near Clewiston, Florida. U.S. Sugar is proposing to install a new bagasse and fuel-oil-fired boiler (boiler 7) at its Clewiston mill. In addition, U.S. Sugar is proposing to raise the stacks of existing boilers to 150 feet above grade. The Clewiston mill is located approximately 102 km north of the Everglades National Park (Everglades), a Class I air quality area administered by the National Park Service.

The addition of boiler 7 will result in a significant increase in emissions of nitrogen oxide (NO_x), sulfur dioxide (SO_2), particulate matter, volatile organic compounds, and carbon monoxide. Based on our review of the permit application, we deem it complete and 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 concerning the best available control technology (BACT) and modeling analyses.

The BACT analysis appears to be complete; however, please note that there are two bagasse boiler control determinations in the RACT/BACT/LAER Clearinghouse database which require more stringent controls than U.S. Sugar is proposing. Both companies will use fluidized bed combustor technology, which may be a viable option for U.S. Sugar. The Thermo Electron Delano Energy Company in California will use limestone injection to control SO_2 emissions, and Thermal $DeNO_x$ to minimize NO_x emissions. The Hawaiian Commerce and Sugar Company, Ltd., will use sorbent injection to control SO_2, selective noncatalytic reduction (SNCR) to control NO_x, and a cyclone and ESP to control particulate matter to 0.03 pounds per million BTU. These are two more companies (besides Okeelanta) which should be compared to U.S. Sugar's proposal during the BACT determination.

Based on U.S. Sugar's analyses, we agree that the emissions from boiler 7, and the proposed increases in stack heights, will not cause or contribute to Class I increment or National Ambient Air Quality Standard violations at the Everglades.

As we requested, U.S Sugar used our Everglades Air Quality Related Values (AQRV) survey to address potential impacts on sensitive resources at the park. On May 10, 1994, U.S. Sugar submitted to you a revised Section 7.0, "Additional Impact Analysis," as an amendment to the permit application. We feel this amendment adequately addresses potential impacts on sensitive resources at the Everglades. However, we needed to redo U.S. Sugar's Level I visibility screening analysis for the Everglades. In the model analysis, U.S. Sugar used the ozone data from the Everglades' AQRV survey. The results showed that the proposed project passed the Level I screening test for the park. However, as stated in our April 26, 1994, letter to you, there was an error with the ozone data in the Everglades' AQRV survey. Therefore, we performed a Level I visibility screening analysis using the correct ozone data and found that the proposed project still passes the Level I screening test. Therefore, we do not anticipate emissions from boiler 7 to result in visible plume impacts at the Everglades.

We appreciate receiving this application early in the review process. Please provide us a copy of your analysis and draft permit upon completion for our review. In the meantime, if you have any questions regarding our comments, please contact Dee Morse of our Air Quality Division in Denver at 303/969-2071.

Sincerely,

C. W. Ogle

FOR James W. Coleman, Jr.
Regional Director
Southeast Region

cc: J. Heron
C. Holladay
D. Knowles, SF Dist.
J. Harper, EPA
M. Benson, US Sugar

Valencia(?)

UNITED STATES SUGAR CORPORATION

Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121 Telex: 510-952-7753

June 27, 1994

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl. 32399-2400

Subject: U. S. Sugar Corporation, Clewiston Mill
Boiler No. 7 - AC 26-238006 and PSD-FL-208

Dear Mr. Brown:

This letter provides supplemental responses of the United States Sugar Corporation (U. S. Sugar) to the Department's March 18, 1994 request for additional information relating to the pending application for a construction permit for Clewiston Boiler No. 7 and augments the preliminary answers provided in Robert F. Van Voorhees' letter, dated June 7, 1994 (Attachment A).

We also enclose a revised Section 5.0, Best Available Control Technology Evaluation (Attachment B) in accordance with the discussion between the Department and U. S. Sugar on June 8, 1994, and revised Tables 2-8 and 3-3 (Attachment C). Answers to the Department's questions are as follows:

BACT DETERMINATION

Particulate Matter (PM):

1. *Please provide the technical, economic and environmental analysis data for using an electrostatic precipitator (ESP) to control particulate matter emissions.*

RESPONSE TO ITEM 1:

This information is presented in the revised Section 5.0, submitted as Attachment B.

2. *The Department has made contacts with several of the ESP's manufacturers that state that ESP technology is technically feasible for this project. Please explain the basis of your conclusion.*

RESPONSE TO ITEM 2:

We have concluded that ESP technology is technically feasible. The relevant information is presented in the revised section 5.0.

3. *Provide a copy of the final ESP test report (include the wet ESP test data) for the tests conducted with United McGill Corporation Mobile Precipitator System in January 1994.*

RESPONSE TO ITEM 3:

The final ESP test report is still in preparation and will be forwarded upon receipt.

4. *Provide a comparison of the design characteristic of the test ESP and ESPs used in other high conductivity ash applications. For example, an ESP was specified in the BACT determination to control particulate emissions from a circulating fluidized bed 338 MMBtu/hr boiler firing bagasse at the Puunene Mill, Hawaiian Commercial & Sugar Company, Limited. The emission limit when firing bagasse in the boiler was specified as 0.03 lb/MMBtu.*

RESPONSE TO ITEM 4:

U. S. Sugar has concluded that an ESP is a feasible control technology for the proposed boiler. Accordingly, we understand that the requested information is not needed and that it will not be necessary for the Department to carry out a detailed comparison between the ESP now proposed for Clewiston Boiler No. 7 and the ESP proposed for installation on the proposed cogeneration boiler at Puuene Mill. Nor would it be possible for us to provide sufficiently detailed engineering information on an ESP for the Puuene mill since that project is not proceeding at present. The proposed boiler authorized by the PSD permit issued by the Hawaii Department of Health to Hawaiian Commercial & Sugar Company, Limited (HC&S) has never been constructed. Moreover, based on our discussions with the Puunene Mill, it is our understanding that HC&S has suspended indefinitely any plans to construct the boiler. As far as we know, there has been no final selection of the ESP that would be installed if the project ever moves forward. In addition, any direct comparison would be complicated by the planned operational difference between the two boilers.

For example, the Puunene Mill was proposed and permitted as an electric power cogeneration boiler burning a fuel mixture of coal and bagasse.

5. *What is the maximum removal efficiency an ESP vendor will guarantee for Boiler No. 7?*

RESPONSE TO ITEM 5:

Based on our discussions with you and your staff, and on the requests for additional information that we have received from the Department, we have held discussions with a number of ESP manufacturers regarding their ability to provide an ESP capable of meeting the 0.03 lb/MMBtu emission limit specified by the Department. At least one vendor has stated that it would guarantee an outlet dust concentration not to exceed 0.03 lb/MMBtu, which would reflect a collection efficiency of 98.52% based on the vendor's projected inlet dust loading of 0.64 gr/ACF and estimated outlet dust loading of 0.095 gr/ACF.

Nitrogen Oxides (NO_x):

6. *The equipment proposed appears to be consistent with other applications which utilize Selective Non Catalytic Reduction (SNCR). However, several costs appear to be either new or higher than other applications - namely the licensing fee, start-up and testing, the model study and annual operating costs. Provide a detailed cost analysis including a copy of the vendor quote for all equipment, tasks included in the performance test and justification for the annual operating labor cost. SNCR installation was specified in the BACT determination for the Puunene Mill boiler.*

RESPONSE TO ITEM 6:

Information responsive to this question was provided in the June 7, 1994 letter form Robert F. Van Voorhees and appended as Attachment A. In addition, the technical and economic feasibility considerations for an SNCR unit are addressed in the revised Section 5.0, submitted as Attachment B to this letter.

Carbon Monoxide (CO):

7. *The Department is taking into consideration the Boiler No. 4 stack test CO emission data. However, you need to evaluate the CO emission rates using the 0.35 lb/MMBtu standard (as in the Okeelanta Power Limited Partnership's permit).*

> *Your company and Okeelanta power are proposing good combustion practices as a control technology to reduce CO and VOC emissions. As such, we fail to understand your rationale for proposing the higher emission limit for this project. Your proposed CO emissions limit is 30 times higher than the Okeelanta project burning biomass fuel.*

RESPONSE TO ITEM 7:

As noted in our June 7, 1994 response, U. S. Sugar is prepared to accept a determination that BACT for carbon monoxide emissions from this boiler is good combustion practices and, based on the representations of boiler manufacturers, a determination that the boiler will be capable of achieving an emission limit of 0.35 lb/MMBtu for carbon monoxide.

General:

8. *Submit appropriate updated tables (Tables 2-3, 2-4, 2-5, and 2-6) showing the revised emission limits for the affected pollutants.*

RESPONSE TO ITEM 8:

Updated Tables 2-3, 2-4 and 2-5 were submitted with the June 7, 1994 letter from Robert F. Van Voorhees as Attachments B, C and D. From our review of the analysis of the emissions reflected in Table 2-6 and our discussion of this assessment with your staff on June 8, we seem to be in agreement that it is not necessary to revise the table. Table 2-6 assesses the potential for the new boiler to emit certain chemicals of concern to the Department -- chemicals which could be toxic if emitted in high enough concentrations. The basis for concluding that it is unnecessary to revise Table 2-6 is that the analysis already presented in the original PSD application demonstrated that the new boiler will not emit any of these chemicals in concentrations that could cause any concern. Thus, the original application projected worst-case annual, 24-hour, and 3-hour scenarios for such emissions that are now far above any emissions that could conceivably occur from the new boiler. Yet these emission scenarios did not pose any concern under the Department's No-Threat Level (NTL) guidelines. The worst case estimates originally presented in Table 2-6 showed that emissions would remain safely below any levels that might prompt concern.

Since then, U. S. Sugar and the Department have discussed and U. S. Sugar has proposed to accept more stringent emission rates and to redesign the proposed boiler and to install additional air pollution control equipment. Specifically, U. S. Sugar will increase substantially the size of the boiler to improve residence time and cause more complete combustion, will use cleaner, lower-sulfur diesel fuel, and will install an ESP on the boiler. These changes will result in substantially lower emission levels than were reflected in Table 2-6. With the reduced emission rates that will result from boiler design improvements and additional pollution control equipment that U. S. Sugar has proposed to adopt, there is an ever greater degree of certainty that the FDEP NTLs will not be exceeded by the proposed project. Therefore, it should be unnecessary to recalculate the emission estimates provided in Table 2-6 only to arrive at lower, even safer emission estimates.

Air Quality Related Values (AQRV):

9. *On February 28, 1994, the Department sent you a letter with a copy of an AQRV survey for the Everglades National Park. This survey was done by the National Park Service (NPS). In order to complete your AQRV analysis, please review the survey, contact Dee Morse of the NPS, coordinate with him any specific concerns the NPS may have with your AQRV analysis, and respond to these concerns, if any. Please provide the Department a copy of your response.*

RESPONSE TO ITEM 9:

The requested information on Air Quality Related Values was submitted to you and the National Park Service under separate cover by Peter Kroll of ICF Kaiser Engineers, Inc., on May 10, 1994. On June 13, 1994, Cleve Holladay informed U. S. Sugar's counsel, Peter Oppenheimer, that FDEP and the National Park Service are satisfied with the revised AQRV survey submitted by Peter Kroll on May 10, 1994.

This should provide all the remaining information necessary to complete your review and approval of the construction permit application for Clewiston Boiler No. 7.

Sincerely,

UNITED STATES SUGAR CORPORATION

Murray T. Brinson

Murray T. Brinson
Vice President
Sugar Processing

MTB:jt

Enclosures

cc: G. Preston Lewis, P.E., FDEP
Douglas G. Outlaw, P.E., FDEP
Teresa M. Heron, FDEP
Cleve G. Holladay, FDEP
William H. Congdon, Esq., FDEP
Peter Kroll, P.E., ICF Kaiser
Robert F. Van Voorhees, Esq., Bryan Cave ✓
Peter Briggs, USSC
Peter Barquin, USSC
Donald Griffin, USSC

5.0 BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION

5.1 BACT APPLICABILITY

5.1.1 Pollutants Requiring BACT Analysis

As presented in Section 3.4, the net increase in the emissions of the following pollutants from the Clewiston mill proposed boiler No. 7 will exceed their respective PSD significant emission rates when oil is fired as an auxiliary fuel (see Table 3-3):

- PM
- SO_2
- NO_x
- CO
- VOCs
- Beryllium
- Sulfuric acid mist

Therefore, BACT analyses for these pollutants is required for the proposed spreader-stoker boiler No. 7 firing bagasse and fuel oil. The complete "top-down" BACT evaluation for each PSD pollutant includes the following:

- Identification of the respective available control technologies
- Evaluation of environmental, energy, and economic impacts of all technically feasible control methods
- BACT analysis summary

5.1.2 Regulatory Guidance

Previous BACT determinations for oil-fired boilers represent the starting point or "top" for the top-down BACT analysis; the minimum acceptable BACT is the applicable NSPS or SIP limit.

BACT determination information was obtained from the USEPA BACT/LAER Informational System (BLIS) database (EPA 1993a) through EPA's National Computer Center located at Research Triangle Park in North Carolina. No BACT determinations for bagasse-fired boilers since 1984 are available from EPA. Florida DEP, however, issued BACT determinations for electric utility steam generating units after the September 1993 submittal of the U.S. Sugar boiler No. 7 PSD permit application. FDEP now says that these BACT determinations may apply to this application via technology transfer.

5.1.2.1 PM

The minimum BACT limit for PM is the NSPS from 40 CFR 60.43b for facilities that combust oil: 0.1 lb/MM Btu, which is also the Florida emission standard for fuel oil combustion. As a minimum, the proposed boiler must also meet an emission limit of 0.2 lb/MM Btu when firing bagasse, which is the State of Florida emission limit for combustion of carbonaceous fuel.

5.1.2.2 SO_2

The minimum BACT limit for SO_2 emissions from fuel oil is the NSPS from 40 CFR 60.42b for facilities that combust oil: 90% SO_2 removal or the use of very-low-sulfur (no more than 0.5% sulfur) fuel oil. There are no applicable emission standards for SO_2 from bagasse-fired boilers; the most relevant precedent appears to be the Clewiston boiler No. 4 permit limit of 0.166 lb/MM Btu when firing bagasse.

5.1.2.3 NO_x

The minimum BACT limit for NO_x emissions is the NSPS from 40 CFR 60.44b for facilities that combust residual oil: NO_x emissions less than 0.3 lb/MM Btu (low heat release) and 0.4 lb/MM Btu (high heat release), except for facilities which have an annual capacity factor for oil of 10% or less. There are no applicable emission limits for NO_x from bagasse-fired boilers; the most relevant precedent appears to be the Clewiston boiler No. 4 permit limit of 180.6 lb/hr when firing bagasse. This equates to about 0.26 lb/MM Btu.

5.2 BACT DETERMINATION FOR PM AND SO_2 EMISSIONS

5.2.1 Identification of PM and SO_2 Emission Control Technologies for Industrial Boilers

In this section, the available control technologies capable of reducing PM and SO_2 emissions produced from firing bagasse and oil as an auxiliary fuel will be identified and evaluated. Potential application of these technologies as BACT for the proposed spreader-stoker boiler is discussed. Table 5-1 is a summary of the potential PM and SO_2 control technologies presented in this section.

In boilers firing fossil fuels, sulfur compounds are produced by the combustion process in which nearly complete oxidation of the fuel-bound sulfur occurs. These sulfur compounds are primarily SO_2

Table 5-1

Summary of Potential PM and SO_2 Control Technologies[1]

Control Technology	Typical Effic. (% PM)	Typical Effic. (% SO_2)	In Service On Bagasse Combustors?	In Service On Other Combustion Sources?	Technically Feasible For This Combustor?
Semi-dry scrubber (Fabric Filter/ESP)	90-99	70-90	No	Yes	Yes[2]
Dry Sorbent Injection (Fabric Filter/ESP)	90-99	40-70	No	Yes	No[3]
Wet Scrubber (Electrostatic Type)	70-98	70-90	No	Yes	No[4]
Wet Scrubber (Impingement Type)	60-90	70-90	Yes	Yes	Yes
Low-sulfur Fuel Oil	N/A[5]	50-98	Yes	Yes	Yes[6]

Notes:

1 Source: Air Pollution Engineering Manual, AWMA, 1992.

2 Unproven technology for this application.

3 No technical or economic advantage over semi-dry scrubber; similar technology.

4 Unproven technology for this application.

5 Not applicable.

6 Would only reduce SO_2 for fuel oil combustion; most of annual heat release comes from bagasse.

with a smaller quantity of sulfur trioxide (SO_3) that eventually is converted to sulfuric acid (H_2SO_4) mist. The amount of SO_2 emissions is directly proportional to the sulfur and sulfate content in the fuel. Reducing SO_2 emissions by boiler modification is not feasible because the firing mechanism does not affect SO_2 emissions. Generally, complete oxidation of sulfur in fuel is readily achieved before the complete combustion of the primarily carbon fuel element in fossil fuel. Typically, SO_2 emission reduction is accomplished along with PM removal by treating the fluegas with a variety of fluegas desulfurization (FGD) processes.

Standard FGD processes for spreader-stoker boilers are wet or semi-dry scrubbers. The following discussion of each potential SO_2 scrubber type includes a description of the technology and, if it is concluded that the technology is technically feasible, the potential SO_2 emission reduction level.

5.2.1.1 Wet Scrubbing Systems

Wet scrubbing of acid gas is an absorption process which involves mass transfer between a soluble gas component (e.g., SO_2) and a solvent liquid (e.g. water). The driving force for gas absorption into the scrubbing liquid is the difference between the partial pressure of the soluble gas in the gas mixture and the vapor pressure of the solute gas in the liquid film in contact with the gas. Therefore the scrubbing liquid must be continually desorbed or a blowdown stream must be routed to wastewater treatment (and replaced with fresh water) in order to maintain a high driving force. Alkaline reagents which change the molecular species of the absorbing pollutant by reaction in the water film are sometimes added to the scrubbing water to increase the driving force for mass transfer.

Wet scrubbing can also remove PM by one or both of the following mechanisms:

- Centrifugal deposition - PM may be "spun out" of a gas stream by centrifugal force induced by a change in gas flow direction. This is not very effective for PM smaller than 5 micron.
- Inertial impaction and interception - when a gas stream flows around a small object, the inertia of the particles causes them to continue to move toward the object, and some of them will be collected.

Wet scrubbing systems include many types of mass transfer units:

- Packed-bed absorbers
- Spray chambers
- Plate columns

- Baffle/impingement chambers
- Inertial types (e.g., venturi)

PM removal is achieved simultaneously with SO_2 removal in these systems. Alternately, specific PM removal systems (e.g., wet electrostatic precipitators or wet fabric filters) can be used instead of, or in combination with, the above units. These PM removal systems have not been used for bagasse combustors or for large industrial boilers, are judged technically infeasible for this application, and will thus not be considered further. The most common by far of the above wet scrubbers for bagasse combustors are the impingement and venturi scrubbers.

In an impingement scrubber, the gas to be cleaned passes through a peripheral nozzle and is guided downward at high velocity into a liquid bath. The level of the liquid bath is maintained slightly below the nozzle by means of an adjustable weir. Collection of fluegas particles is by both direct inertial impaction with the liquid bath and by collision with droplets atomized by the action of the gas stream upon the liquid bath. Mist elimination, achieved by centrifugal action and swirl vanes, precedes gas discharge.

In the venturi scrubber, the gases are passed through a venturi throat where low-pressure water is added. The throat provides a smaller cross-sectional area for gas flow, and thus increases gas velocity. Extreme turbulence in the throat atomizes the water into small droplets and promotes intimate contact with the gas and PM. The droplets and wetted particles are then collected in a mist elimination device. For a given collection efficiency, these devices normally require a greater pressure drop than the impingement scrubber. In addition, pretreatment mechanical collectors are normally necessary downstream of bagasse combustors to remove the larger abrasive particles in order to decrease wear on the venturi throat.

Wet scrubbing processes are capable of achieving high removal efficiencies for soluble acidic gases (e.g., HCl and HF) with water which has a neutral or lower pH. Gases of more limited solubility (e.g., SO_2 or Cl_2) can be absorbed more readily in an alkaline solution than in water alone. There is little test data available for absorption of SO_2 from fuel oil combustion in a wet scrubber using water only, so we have conservatively assumed that there will be no removal efficiency for non-alkaline wet scrubbing for fuel oil firing.

The pH of the process water used at the Clewiston mill has been measured in the range of 7 to 8, which is alkaline to neutral, and theoretically should absorb some SO_2 from the gas stream. The emissions test data from bagasse boilers show a significant reduction in theoretical SO_2 emissions upstream of the scrubber, resulting in overall reduction of greater than 90% of the theoretical amount of SO_2. This additional reduction probably takes place in the boiler, where the bottom ash and fly ash absorb much of the SO_2.

There is significant test data on the performance of wet scrubbers for bagasse combustion. Although the wet scrubbing process can potentially achieve 95% removal efficiency for SO_2 and PM, a somewhat more conservative value of 90% will be used in the BACT analysis.

The combustion gases entering the wet scrubber at 300-350°F are cooled and saturated by the scrubbing liquid to an adiabatic saturation temperature of about 160°F. This low temperature will also enhance the removal of condensible trace elements, such as toxic metals, in the wet scrubber.

5.2.1.2 Semi-dry Scrubbing Systems

In the semi-dry scrubbing process, the fluegas enters a spray dryer and contacts an atomized slurry of lime ($Ca[OH]_2$), sodium bicarbonate ($NaHCO_3$) or sodium carbonate sorbent. The SO_2 gas reacts with lime or sodium sorbent to form initially either calcium sulfite ($CaSO_3 \bullet 0.5H_2O$) or sodium bisulfite ($NaHSO_3$). Upon further oxidation or SO_2 absorption enhanced by the drying process, the sulfite salts will be transformed into calcium sulfate ($CaSO_4 \bullet 2H_2O$) or sodium sulfite/sulfate solids. Industrial and utility spray dryers typically use lime as the reagent because it is more readily available and cheaper than sodium bicarbonate.

Lime slurry is injected into the spray dryer chamber through either a rotary atomizer or pressurized dual-fluid nozzles. In rotary atomizers, the slurry is fed to the center of a rapidly rotating disk where it flows outward to the edge of the rapidly rotating disk. The slurry is atomized by centrifugal force as it leaves the surface of the disk. Dual-fluid nozzles use kinetic energy to atomize the slurry. High-velocity air or steam is injected into the nozzle, breaking the slurry into fine droplets, which are ejected at near-sonic velocities into the spray drying chamber.

As the combustion gases contact and pass through the cloud of atomized lime slurry, the water content of the slurry will cool the gases while being vaporized. Simultaneously, the lime in the slurry will react with the SO_2 in the fluegas to produce calcium salts. This concurrent evaporation and reaction in the spray drying process increases the moisture and particulate content of the fluegas and reduces the fluegas temperature. The dried solids exiting the spray-dryer/absorber contains fly ash, calcium salts and excess lime. Moisture content of the dried solids leaving the absorber is about 3-5%. The spray-dryer/absorber is designed to provide sufficient residence time (10 to 15 seconds) to complete the drying and absorbing processes.

In the spray-dryer/absorber, the amount of water used is optimized to produce an exit gas stream with dried material and no liquid discharge. The fluegas temperature exiting the spray dryer is typically 20-40°F above adiabatic saturation. The dried reaction products and fly ash are both removed from the fluegas by a particulate collection device downstream.

Key design and operating parameters that can significantly affect spray dryer performance are reagent-to-sulfur stoichiometric ratio, slurry droplet size, makeup water characteristics, gas residence time, and scrubber outlet temperature. An excess amount of lime above the theoretical requirement is fed to the spray dryer to compensate for mass transfer limitations and incomplete mixing. Smaller droplet size increases the surface area for reaction between lime and acid gases and increases the rate of water evaporation. A longer residence time results in higher chemical reactivity. The scrubber outlet temperature is controlled by the amount of water in the slurry. Typically, effective utilization of lime and effective sulfur dioxide removal occur at temperatures close to adiabatic saturation, but the fluegas temperature must be kept high enough to ensure the slurry and reaction products are adequately dried prior to the particulate collection process.

The semi-dry scrubber is located upstream of the particulate control device, which is either an electrostatic precipitator (ESP) or a fabric filter (baghouse) system. A baghouse can provide greater SO_2 removal compared to an ESP system. When a baghouse is used, a layer of porous filter cake forms on the filter bag surfaces. This filter cake contains unspent reagent which provides for additional SO_2 removal because the fluegases pass through the filter cake. Thus, for the SO_2 BACT analysis, the semi-dry scrubber consists of a spray dryer absorber and a fabric filter.

Based on BACT determinations previously issued, the semi-dry scrubber system can achieve between 70-95% SO_2 removal for oil-fired boilers, with 90% removal being assumed for this analysis based on discussions with FGD vendors.

In order to attain this high SO_2 removal efficiency, the semi-dry scrubbing process must include recirculation of the dried solids to the lime slurry. This recirculation will increase the concentration of toxic metals (e.g., lead, chromium) on the dried solids, thereby potentially increasing metals emissions from the stack. In addition, the higher temperature of the stack gas compared to the wet scrubber may lead to higher gas-phase metal emissions compared to a wet scrubber.

5.2.1.3 Fabric Filters and Dry Sorbent Injection

Fabric filters consist of semipermeable woven or felted materials that constitute the substrate for the approaching dust. The deposited PM layer enables the high-efficiency capture of the particles once a uniform surface layer has been established. The fabric is periodically partially cleaned of accumulated particles by compressed air pulses, mechanical shaking, or reverse flow. Particles are captured by the following mechanisms:

- Interception - the particle is carried by a gas streamline directly toward a fiber target.

- Inertial impaction - the particle is on a gas streamline that would carry it around the fiber target, but the particle's inertia causes it to leave its streamline and strike the target.

- Diffusion - the particle is so small that its path is highly erratic and random excursions carry the particle to a target fiber (for particles less than 0.1 micron)

- Sieving - the particle is trapped because it is too large to pass through the specific pore

Many baghouses have been installed on coal, wood and solid-waste-fired boilers. The principal drawback foreseen by potential users of baghouses is a fire danger resulting from collection of combustible carbonaceous fly ash. The fire potential could possibly be reduced by extensive precautions, but such measures have not been demonstrated in actual application on bagasse-fired boilers.

Additional problems with baghouses are plugging, solid waste disposal of a dry product, and potential high maintenance costs for filter replacement. Particulate emission controls via fabric filtration have not been installed on any bagasse-fired boiler. Few full-scale baghouses have been installed on any types of large nonfossil-fuel-fired boilers. Because of the unproven ability of baghouses to operate reliably and effectively on bagasse-fired boilers, they were not considered further in the BACT analysis.

Another disadvantage to fabric filtration is its inability to remove gaseous pollutants from the gas stream (e.g., SO_2); another control device would be required to remove pollutants such as SO_2. This is generally addressed by the use of a spray dryer absorber upstream of the fabric filter, as in the case of the semi-dry scrubber previously discussed. Alternately, a dry sorbent injection (DSI) system can be used. In the DSI system, the combustion gas is usually humidified to within 25-50°F of the adiabatic saturation temperature with water sprays in a spray chamber. A dry sorbent, such as hydrated lime or sodium bicarbonate, is then injected into the fluegas.

The DSI can not attain as high of an SO_2 removal efficiency as a semi-dry scrubbing system, because the dry solid does not absorb the acid gas as readily as the moist lime does in a semi-dry system. Although there is little technical or economic reason to choose a DSI system for a new installation, DSI has proved to be a good retrofit technology for existing combustion systems which already have a fabric filter or ESP, but no acid gas removal. Because the DSI system has no technical, environmental or economic advantages over a semi-dry system for this application, it is considered infeasible for this combustor, and will not be considered further.

5.2.1.4 Electrostatic Precipitators

Electrostatic precipitators (ESP) particulate collection is accomplished by first imparting an electrical charge to the particles, allowing the charged particles to migrate to a collecting electrode, and dislodging the collected particles from the collecting electrodes. Particle charging is normally accomplished with a high-voltage DC corona. Particle removal is performed by rapping or vibrating the collecting electrodes.

ESPs have the inherent disadvantage of removing only particulate matter. Another control device would be needed to remove gaseous pollutants such as SO_2. This is typically addressed by the use of dry sorbent injection, as discussed previously. Disposal of a dry solid waste product would also be required.

ESPs are in operation on many wood, solid-waste and coal-fired boilers. They have not, however, been installed on bagasse-fired boilers. Because of the uncertainty associated with application of ESPs to bagasse boilers, this technology is considered to be unproven.

Based on the direction of FDEP, however, an ESP will be considered by U.S. Sugar for the PM BACT, based on previous PM BACT determinations done for electric utility steam generating units subject to the NSPS in 40 CFR 60 Subpart Da for 0.03 lb/MM Btu.

5.2.1.5 Low-sulfur Fuel Oil

The sulfur content of residual oil typically ranges from 0.3-3.0% by weight. Because the level of SO_2 emissions is directly related to the amount of sulfur in the fuel, a low-sulfur-containing fuel can be used to meet the SO_2 emission limitation specified by the NSPS regulations.

Under the current NSPS regulations for industrial steam generators (40 CFR 60, Subpart Db), an SO_2 emission rate of 0.5 lb/MM Btu must be met by the proposed boiler No. 7. The sulfur content of the residual oil used in boilers No. 1, 2 and 3 is 2.5% which is equivalent to an uncontrolled SO_2 emission factor of approximately 2.7 lb/MM Btu. U.S. Sugar could comply with the NSPS by using "very-low-sulfur" residual oil (no more than 0.5% sulfur), as 40 CFR 60.42b specifically allows. This would be equivalent to an uncontrolled SO_2 emission factor of approximately 0.5 lb/MM Btu.

U.S. Sugar Corporation instead proposes to use "very-low-sulfur" distillate (diesel) fuel oil (no more than 0.05% sulfur) to significantly reduce SO_2 emissions below the NSPS limit.

The intent of U.S. Sugar Corporation has and always will be to minimize the burning of fuel oil in the existing boilers as well as the proposed boiler No. 7. For example, during 1992 fuel oil provided less than 1% of the Clewiston mill's total heat input requirements. Oil is normally required for starting up the boilers at the beginning of the crop-year (generally requires less than 24 hours). After startup, oil will only be fired when the supply of bagasse to the boiler is interrupted.

Oil is very costly; therefore, simple economics dictate minimization of fuel oil usage. The permit application provides for up to 3,000,000 gallons per year of fuel oil to be burned in the proposed boiler. Actual fuel oil usage is expected to be below this level.

The firing of a very-low-sulfur diesel fuel oil in the proposed boiler will be costly to U.S. Sugar Corporation, owing to the differential between 2.5% sulfur residual oil and 0.05% sulfur diesel fuel, which is currently $9.35/bbl and could be substantially higher in the future. In addition, a dedicated fuel oil tank, pumps, and piping will be required for the storage and handling of low-sulfur diesel oil.

5.2.2 Evaluation of Technically Feasible PM and SO_2 Control Methods

This section examines the three technically feasible alternative PM and SO_2 control methods (i.e., the wet scrubber, the semi-dry scrubber, and low-sulfur fuel oil in conjunction with an ESP) identified in the previous discussion. Each alternative will be further examined with regard to its technical issues, environmental effects, energy requirements, and economic impacts.

5.2.2.1 Ranking of Feasible Control Technologies

A baseline emission level must be established as the basis for top-down BACT ranking and for economic analysis purposes. The baseline is defined as the uncontrolled emission rate of the process being reviewed. Thus, the SO_2 and PM emission level associated with the firing of only 2.5% sulfur oil in boiler No. 7 and no add-on SO_2 or PM controls will be used as the baseline emission level.

All three control options can achieve SO_2 removal efficiencies of 90% for bagasse. The wet scrubber can not, however, achieve 90% SO_2 removal efficiency for fuel oil without using alkali. U.S. Sugar Corporation does not use alkali scrubbing liquid in any of its existing impingement scrubbers, and therefore does not plan to use it for the boiler No. 7 scrubber. In addition, the semi-dry scrubber can achieve higher removal efficiency for PM. Therefore, the BACT top-down hierarchy ranks the semi-dry scrubber first, the ESP/low-sulfur oil option second, and the wet scrubber third.

5.2.2.2 Analysis of Add-On Scrubbing Systems

Technical Issues

Wet Scrubber. The impingement and inertial-type wet scrubbers can typically achieve SO_2 removal efficiencies in the 70-95% range and are designed for simultaneous particulate removal. Of all the potential add-on control technologies discussed in the previous section, only the impingement and venturi wet scrubbers have been proven on bagasse-fired boilers.

A venturi scrubber was not chosen for consideration in the detailed BACT evaluation because it has not proven to be a more efficient control device than the impingement scrubber. BACT guidelines do not require further analysis of alternative control systems which cannot achieve a greater degree of emission reduction than a functionally similar alternative. The venturi is also considerably more expensive to install and operate, requires a greater pressure drop (2 to 3 times that of the impingement scrubber), with a correspondingly greater energy consumption, and requires more water. The higher maintenance costs are due to the abrasive nature of the fly ash and high gas velocities encountered in the venturi and across the exhaust fan, which accelerates wear of exposed surfaces. Venturis must be preceded by mechanical collectors to reduce wear, which further increases capital and operating costs of the system.

Venturi scrubbers are currently operating on a total of six boilers in the Florida sugar industry. At both Okeelanta and Talisman, mechanical cyclone collectors precede the venturi scrubbers in order to remove larger particles. At Okeelanta, the venturi scrubber typically operates at a pressure drop of 16 inches H_2O. At Talisman, the venturis operate typically at 14 inches H_2O pressure drop. Compliance test results have varied widely, ranging from 0.09 lb/MM Btu to 0.30 lb/MM Btu. The average of all tests for all boilers is 0.20 lb/MM Btu. The data show that the venturi scrubbers have not achieved a greater degree of emission reduction than that achieved with the impingement scrubber.

Wet scrubbers are the only control devices currently in operation on bagasse/oil-fired steam boilers in the Florida sugar industry. These scrubbers are mainly of the impingement type. Venturi scrubbers are also utilized on a few bagasse/oil-fired boilers in Florida. The Background Information document for Nonfossil Fuel-Fired Industrial Boilers (EPA, 1982) shows that wet scrubbers are the only PM control devices currently in use on bagasse-fired boilers in the United States, other than low-efficiency centrifugal collectors (e.g., cyclones). The following is a summary of current scrubber installations on bagasse/oil-fired boilers in Florida:

Mill	No. of Bagasse/ Oil Boilers	No. of Impingement Scrubbers	No. of Venturi Scrubbers
U.S. Sugar Clewiston	6	6	0
U.S. Sugar Bryant	4	4	0
Sugar Cane Growers Coop.	6	6	0
Osceola Farms	5	5	0
Atlantic Sugar Association	5	5	0
Okeelanta	8	5	3
Talisman	3	0	3
TOTAL	37	31	6

The venturi scrubber and impingement scrubber are currently the only types operating in the Florida sugar industry; note that impingement scrubbers represent 84% of all scrubbers currently in use, with venturi scrubbers accounting for the remaining 16%.

U.S. Sugar Corporation has installed six impingement scrubbers at the Clewiston mill and four at the Bryant mill. There were some problems with the first units installed many years ago; as these "first generation" problems were identified, they were corrected by retrofit and by improved system designs. Some specific improvements made to earlier designs include:

- Changing spray location and flowrate
- Modifying weir height
- Relocating induced draft fans from upstream to downstream of the wet scrubbers, thus avoiding flyash abrasion problems

U.S. Sugar Corporation has therefore improved the performance of these impingement scrubbers over the years and has an in-depth understanding of the scrubber technology.

The most important design parameter for wet scrubbers is the impingement effect, which causes the intimacy of contact between the liquid and gas phases. Important operational parameters include scrubber pressure drop and scrubbing liquid flowrate.

The impingement scrubber can attain a particulate emission of 0.15 lb/MM Btu and will remove 90% or more of the theoretical SO_2. The pH of the scrubber water used at the Clewiston mill has been measured in the range of 7 to 8, which is alkaline to neutral, and will thus absorb some SO_2 from the gas stream. The SO_2 test data from bagasse boilers also show a significant reduction in theoretical SO_2 emissions elsewhere in the process, resulting in overall reduction of greater than 90% of the theoretical amount of SO_2. This additional reduction probably takes place in the boiler, where the bottom ash and fly ash absorb the SO_2.

Semi-dry Scrubber. The semi-dry scrubber requires a separate particulate control system to be installed downstream of the spray dryer. In addition, it requires more precise control and operator attention than the wet scrubber system. From an operating standpoint, a narrow operating temperature window (inlet and outlet of the spray dryer) has to be strictly adhered to in order to avoid potential problems, such as:

- Low spray dryer inlet temperature, which will reduce the amount of lime slurry which can be dried in order to absorb acid gas

- High fabric filter inlet temperature and potential for baghouse fire

- Low baghouse inlet temperature and potential incomplete drying of solids and subsequent coating/plugging of bags

Most importantly to U.S. Sugar Corporation, the reliability of a semi-dry scrubber is not proven for bagasse-fired boilers.

Electrostatic Precipitator. One of the key design parameters for an ESP is flyash resistivity. It may be possible to overcome problems associated with high flyash resistivity if a significant amount of wood chips and coal are combusted in addition to bagasse, thus changing the flyash resistivity considerably from exclusively bagasse combustion. U.S. Sugar, in contrast, will only combust bagasse with a very small amount (less than 10% on an annual basis) of fuel oil. Based on the above reasons, U.S. Sugar is still concerned that an ESP may not be technically feasible for the new bagasse combustor.

Testing conducted by US Sugar with a dry ESP has confirmed the validity of these concerns (see Attachment C). The dry ESP was unable to achieve, or even approach, the requisite removal efficiency with bagasse flyash. Additional testing with a wet ESP suggested that different results might be achieved with that type of process, but raises additional concerns about how to judge the capability of a control technology not yet proven in practice on bagasse boilers. At the very least, this testing confirms that the technology approved for the electric utility steam generating units cannot simply be "transferred" and presumed applicable to Clewiston boiler No. 7, especially where ESPs have not ever been designed, tested, or operated on bagasse combustion.

Environmental Effects

Wet Scrubber. The primary environmental concern of using the wet scrubber is the process wastewater and the wastewater sludge generated. These waste streams require proper treatment and disposal, but the Clewiston mill already has a wastewater treatment system with adequate capacity.

Semi-dry Scrubber. The major environmental issues concerning the use of the semi-dry scrubber process are solid waste disposal and water demand. Calcium salts will be generated from the semi-dry scrubbing process that will require disposal. For every ton of SO_2 removed, there will be 6 tons of solid waste generated. A dry FGD system for Clewiston could therefore generate up to 6,350 tons of solid waste each year, which would be landfilled off-site.

ESP/Low-sulfur Oil. The environmental issue associated with the ESP is solid waste disposal.

Energy Requirements

The wet and semi-dry scrubber and ESP require electrical power to drive various mechanical equipment, including fans and pumps. The estimated energy requirement is approximately 340 kw for the wet scrubber and approximately 595 kw for the semi-dry scrubber. These estimated energy requirements are calculated assuming the maximum allowable oil-firing for the facility. The additional energy for the ESP/low-sulfur fuel oil option is 31 kw.

Economic Analysis

This section presents the total capital investment (TCI) and the total annualized cost (AC) of the wet scrubber, the semi-dry scrubber, and the ESP/low-sulfur oil options for the proposed Clewiston boiler No. 7. Capital costs were developed from basic equipment costs for each process and with standard cost factors for estimating the direct and indirect costs of the emission control systems (EPA, 1990b).

The equipment cost for the semi-dry scrubber system was based on the budgetary quotations obtained from control system vendors. The purchased equipment and installed costs are \$3.99 million (MM) and \$11.2 MM, respectively, for the semi-dry scrubber.

The installed cost for the wet scrubber system is approximately \$0.57 MM, about 1/20 the cost of the semi-dry scrubber. This cost was developed from vendor quotation and U.S. Sugar Corporation experience with other comparable wet scrubbers (e.g., boiler No. 4).

The purchased equipment cost of \$1.1 MM for the ESP is based on vendor quotations. The calculated total installed cost is \$2.6 MM, but vendor quotations of installed cost have been as high as \$2.75 MM.

All operating costs were developed based on an equivalent 1,752 hr/yr operation on oil for boiler No. 7. This represents the number of hours at maximum oil-firing capacity to achieve 10% of the total facility annual heat input (i.e., 4,861 MM Btu/yr divided by 255 MM Btu/hr). The cost estimates for the control systems are presented in Table 5-2.

5.2.2.3 PM and SO_2 BACT Summary

The BACT analysis for PM and SO_2 control has evaluated the feasible add-on control alternatives (i.e., the wet and semi-dry scrubbers and the ESP/low-sulfur oil). Based on the AC presented in Table 5-3 for the dry and wet scrubber systems and ESP/low-sulfur fuel oil, the average cost effectiveness (ACE) and incremental cost effectiveness (ICE) for these approaches are shown in Tables 5-3 and 5-4. The cost effectiveness figures are based on the worst-case condition of firing up to 10% fuel oil (with 2.5% sulfur) and 90% bagasse in a single year (producing 4,435 TPY of PM and 1,136 TPY of SO_2).

The ACE values are $797, $205 and $127 per ton of PM removed for the semi-dry scrubber, ESP/low-sulfur oil, and wet scrubber, respectively. The ICE values are $253 MM, $1,460 and $127 per ton of PM removed for the semi-dry scrubber, ESP/low-sulfur oil, and wet scrubber, respectively. The ICE value for semi-dry scrubbing is much higher than the levels that FDEP and EPA have considered as reasonable for controlling PM emissions (i.e., $4,000 per ton of PM removed). Therefore, the use of a semi-dry scrubber is considered as economically infeasible for PM removal. The next alternative in the top-down ranking is the ESP, which is economically feasible for PM removal.

The ACE values are $3,336, $979 and $1,099 per ton of SO_2 removed for the semi-dry scrubber, ESP/low-sulfur oil, and wet scrubber, respectively. The ICE values are $11,966, $812 and $1,099 per ton of SO_2 removed for the semi-dry scrubber, ESP/low-sulfur oil, and wet scrubber, respectively. The low-sulfur oil, which is the most economically feasible control option for SO_2 removal.

Conclusion

The top-down BACT analysis for PM and SO_2 for the proposed boiler firing bagasse and oil as auxiliary fuel is summarized in Tables 5-3 and 5-4. As discussed above, the analysis has indicated that significant economic, environmental and energy costs are associated with the semi-dry scrubber option. The estimated costs for PM and SO_2 controls are unreasonable for the semi-dry scrubber, particularly considering that U.S. Sugar does not intend to burn oil for more than a 10% annual capacity factor, and that oil will be burned only if the supply of bagasse is not adequate.

No other facility in the United States has been identified where add-on SO_2 controls were required as BACT when the heat input due to fossil fuels was less than 30%. In three recent BACT

Table 5–2. Cost Analysis for PM and SO2 Emissions Control

Cost Items	Cost Factors	Semi–dry Scrubber	Wet Scrubber	ESP	Low–S Oil
DIRECT CAPITAL COSTS (DCC)					
(1) Purchased Equipment Cost:					
(a) Basic Equipment/Services	Vendor Quotation	$3,990,000	$206,000	$914,000	$173,250
(b) Auxilary Systems	Vendor Quote (included in 1a)	$0	$0	$0	$0
(c) Instrumentation & Controls	0.10(1a + 1b)	$399,000	$20,600	$91,400	$17,325
(d) Modifications to Other Equipment	None	$0	$0	$0	$0
(e) Freight	0.05(1a + 1b + 1c + 1d)	$219,450	$11,330	$50,270	$9,529
(f) Florida Sales Tax	0.06(1a + 1b + 1c + 1d)	$263,340	$13,596	$60,324	$11,435
(g) Purchased Equipment Subtotal	(1a + 1b + 1c + 1d + 1e + 1f)	$4,871,790	$251,526	$1,115,994	$211,538
(2) Direct Installation Cost:	0.67(1g)	$3,264,099	$168,522	$747,716	$141,731
Total DCC:	(1g + 2)	$8,135,889	$420,048	$1,863,710	$353,269
INDIRECT CAPITAL COSTS (ICC)					
(3) Indirect Installation Cost:					
(a) Engineering & Supervision *	0.20(1g)	$974,358	$50,305	$223,199	$42,308
(b) Construction & Field Expenses *	0.20(1g)	$974,358	$50,305	$223,199	$42,308
(c) Construction & Contractor Fee *	0.10(1g)	$487,179	$25,153	$111,599	$21,154
(d) Contingencies *	0.10(1g)	$487,179	$25,153	$111,599	$21,154
(4) Other Indirect Cost:					
(a) Start–up & Testing *	0.03(1g)	$146,154	$7,546	$33,480	$6,346
(b) Working Capital	(8a + 8b)/12	$4,479	$0	$0	$55,000
Total ICC	(3) + (4)	$3,073,707	$158,461	$703,076	$188,269
TOTAL CAPITAL INVESTMENT (TCI	DCC + ICC	$11,209,596	$578,510	$2,566,786	$541,538
DIRECT OPERATING COST (DOC):					
(5) Operating Labor:					
(a) Operator	8,760 hr/yr @ $17/hr * 3/8	$55,845	$55,845	$55,845	$0
(b) Supervisor	15% of operator cost	$8,377	$8,377	$8,377	$0
(6) Maintenance Labor & Materials *	0.05(1g)	$243,590	$12,576	$55,800	$10,577
(7) Utilities	$0.08/kw–hr, $0.27/Mgal				
(a) Electricity	KW:595 SDS,340 wet,31 ESP	$416,976	$238,272	$21,725	$0
(b) Water	gpm 71 semi–dry, 500 wet	$5,038	$35,478	$0	$0
(8) Chemicals and Fuel					
(a) Lime (97% purity)	$50/ton x 1075 tpy	$53,750	$0	$0	$0
(b) Oil Premium (cost difference)	$0.22/gallon x 3 MM gal/yr	$0	$0	$0	$660,000
(9) Solids Disposal	$27/ton x 6,350 tpy SDS, 5,275 tpy ESP	$171,450	$0	$142,425	0
Total DOC	(5)+(6)+(7)+(8)+(9)	$955,025	$350,548	$284,171	$670,577
INDIRECT OPERATING COST (IOC)					
(10) Overhead *	60% of (5) and (6)	$184,687	$46,079	$72,013	$6,346
(11) Property Taxes *	1% of TCI	$112,096	$5,785	$25,668	$5,415
(12) Insurance *	1% of TCI	$112,096	$5,785	$25,668	$5,415
(13) Administration *	2% of TCI	$224,192	$11,570	$51,336	$10,831
Total IOC	(10) + (11) + (12) + (13)	$633,071	$69,219	$174,684	$28,008
TOTAL OPERATING COST (TOC)	DOC + IOC	$1,588,096	$419,767	$458,856	$698,585
CAPITAL RECOVERY COST (CRC)	0.1627(TCI)	$1,823,801	$94,124	$417,616	$88,108
ANNUALIZED COST (AC)	DOC + IOC + CRC	$3,411,897	$513,891	$876,472	$786,693

Notes:
* Cost factors are based on EPA's OAQPS Control Cost Manual, Fourth Edition – Chapter 6.
Operations based on 7,008 hr/yr on bagasse and 1,752 hr/yr on oil

TABLE 5-3. SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS FOR PM

FEASIBLE CONTROL TECHNOLOGY	REMOVAL EFFICIENCY	CONTROLLED EMISSIONS TPY	EMISSION REDUCTION TPY (a)	AC $/YR (b)	ACE $/Ton (c)	ICE $/Ton (d)	IEI (e) MW-hr	TOXICS IMPACT?	AEI? (f)
Semi-dry scrubber	99%	64.6	4,280.9	3,411,897	797	253,542,500	5,212	Yes	Yes
ESP	99%	64.6	4,280.9	876,472	205	1,460	272	Yes	No
Wet scrubber	93%	313.0	4,032.5	513,891	127	127	2,978	No	No
Baseline	0%	4,345.5	0	0	0	0	0	No	Yes

(a). Emissions reduction over baseline level of no controls. PM baseline of 4,345.5 TPY derived from AP-42 factor of 15.6 lb PM/ton bagasse at maximum annual throughput and AP-42 factor for PM from fuel oil.

(b). AC: total annualized cost (capital, direct and indirect) of purchasing, installing and operating the proposed control alternative.

(c). ACE (average cost effectiveness) is annualized cost for the control option divided by the emission reductions resulting from the option.

(d). ICE (incremental cost effectiveness) is difference in annualized cost for the control option and the next most effective control option divided by difference in emission reduction resulting from the respective alternatives.

(e). IEI (incremental energy impact) difference in total project energy requirements with the control alternative and the baseline expressed in equivalent MW-hr

(f). AEI: adverse environmental impact

TABLE 5-4. SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS FOR SO2

FEASIBLE CONTROL TECHNOLOGY	REMOVAL EFFICIENCY	CONTROLLED EMISSIONS TPY	EMISSION REDUCTION TPY (a)	AC $/YR	ACE $/Ton	ICE $/Ton	IEI MW-hr	TOXICS IMPACT?	AEI?
Semi-dry scrubber	90%	113.6	1,022.7	3,411,897	3,336	11,966	272	Yes	Yes
Low-sulfur oil	71%	333.0	803.3	786,693	979	812	5,212	No	No
Wet scrubber	41%	668.8	467.5	513,891	1,099	1,099	2,978	No	No
Baseline	0%	1,136	0	0	0	0	0	No	Yes

(a). Emissions reduction over baseline level of no controls. SO2 baseline of 1,136 based on AP-42 factors for firing 2.5% S oil at maximum annual rate and mass balance calculations for firing bagasse in No. 7 boiler.

determinations for multifuel stoker boilers, coal is used as supplementary fuel for up to 30% of the heat input without the use of add-on SO_2 controls.

Based on these considerations, **using low-sulfur diesel fuel oil (maximum of 0.05% sulfur) as the compliance fuel, not to exceed 10% of the total annual heat input, represents BACT for SO_2 emissions for the proposed boiler No. 7.**

Because of its high removal efficiency for PM, although it is an unproven technology for bagasse combustion, **the ESP is proposed as BACT for PM emissions for the proposed boiler No. 7.**

The proposed PM and SO_2 BACT limits for boiler No. 7 are as follows:

- Bagasse-firing: 0.03 lb PM/MM Btu
  0.1667 lb SO_2/MM Btu

- Oil-firing: 0.03 lb PM/MM Btu
  0.05 lb SO_2/MM Btu

5.3 BACT EVALUATION FOR NO_X EMISSIONS

5.3.1 Identification of NO_x Emission Control Technologies for Industrial Boilers

In this section, the available control technologies capable of reducing NO_x emissions produced from firing bagasse and oil as an auxiliary fuel will be identified and evaluated. Potential application of these technologies as BACT for the proposed spreader-stoker boiler, rated on oil at 225 MM Btu/hr, is discussed. Table 5-5 is a summary of the potential NO_x control technologies presented in this section.

NO_x emissions from combustion of bagasse and fuel oil consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at high temperatures. Formation of thermal NO_x depends on flame temperature, gas residence time in the peak temperature zone, and fuel-air stoichiometric ratio. In general, lower operating temperature, less gas residence time, and off-stoichiometric fuel-air ratio will reduce thermal NO_x formation.

Fuel-bound NO_x is created by the oxidation of nitrogen in the fuel; on the average, about 45% of the nitrogen in fuel oil is converted to NO_x. Controlling the nitrogen content of the fuel is the primary factor in reducing fuel-bound NO_x formation.

Table 5-5

Summary of Potential NO_x Control Technologies[1]

Control Technology	Typical Efficiency (%)	In Service On Bagasse Combustors?	In Service On Other Combustion Sources?	Technically Feasible For This Combustor?
Selective Catalytic Reduction	60-90	No	Yes	No
Selective Noncatalytic Reduction	40[2]	No	Yes	Yes[3]
Fluegas Recirculation	20-40	No	Yes	Yes[4]
Low-NOx Burner	30-60[5]	No	Yes	Yes
Low-nitrogen Fuel Oil	25-50[6]	Yes	Yes	Yes
Overfire Air/Good Combustion Practices	10-30	Yes	Yes	Yes[7]

Notes:

1 Source: Air Pollution Engineering Manual, AWMA, 1992.

2 Source: FDEP final determination for bagasse cogeneration boiler.

3 Unproven technology for this application.

4 Unproven technology for this application.

5 Would only reduce NOx for fuel oil combustion; most of annual heat release comes from bagasse.

6 Would only reduce NOx for fuel oil combustion; most of annual heat release comes from bagasse.

7 Currently part of combustor design.

The control of NO_x emissions from steam generators can be accomplished through the application of combustion modifications and/or post-combustion technology (EPA, 1991a). The combustion modifications evaluated include:

- Low-NO_x burners (LNB)
- Off-stoichiometric combustion (OSC)
- Overfire air (OFA)
- Flue gas recirculation (FGR)
- Low-nitrogen fuel oil

Post-combustion technologies include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR).

5.3.1.1 Combustion Modifications

Low-NO_x Burners

LNB technology reduces NO_x emissions by staging combustion in the burner. This is accomplished through the creation of fuel-rich and fuel-lean zones in the central and outer portions of the flame, respectively. This limits the flame temperature and thus the amount of thermal NO_x formed during combustion. The amount of reduction achievable is dependent upon the boiler and burner design, and actual operating practices.

LNB technology is not applicable to bagasse combustion, because the bagasse is burned on a vibrating grate and not in a burner. Fuel oil is used only for supplemental firing in relatively minor quantities compared to bagasse, but LNB is feasible for fuel oil.

Over-Fire Air

OFA for a bagasse boiler involves supplying combustion air through ports above the vibrating grate. Bagasse boilers generally use OFA for 20% of the total air requirements; about 80% is supplied under the grates.

Data are not readily available to support a definitive NO_x reduction for additional OFA. Bagasse boilers are generally operated in an air-rich condition (30-50% excess air) which effectively produces lower NO_x emissions.

Flue Gas Recirculation

FGR involves recycling a portion of the fluegas back into the primary combustion zone. NO_x emissions are reduced by lowering the peak flame temperature and lowering the oxygen concentration in the primary flame zone. Although FGR is effective in reducing NO_x emissions from coal, natural gas, and oil firing, it is unknown whether FGR will substantially reduce NO_x emissions in bagasse boilers. FGR would substantially affect the unit efficiency through lowering fuel efficiency and increasing fan power. In addition, the recirculation of the abrasive flyash would greatly increase wear on the fan and ductwork. This technology is deemed technically feasible for bagasse combustion, although it has not yet been proven.

Low-nitrogen Fuel Oil

The nitrogen content of residual oil typically ranges from 0.2-0.6% by weight. Because the level of fuel-bound NO_x emissions is directly related to the amount of nitrogen in the fuel, a low-nitrogen-containing fuel can be used to meet the NO_x emission limitation specified by the NSPS regulations for industrial boilers.

Under the current NSPS regulations for industrial steam generators (40 CFR 60, Subpart Db), a facility firing less than 250 MM Btu/hr which combusts distillate oil or residual oil with a nitrogen content of 0.3% or less, and having a federally enforceable annual capacity factor of 10% or less for oil is not subject to quantitative NO_x emission limits.

5.3.1.2 Post-combustion Controls

Selective Non-Catalytic Reduction

SNCR describes post-combustion control technologies that remove NO_x by the addition of a reactant such as urea or ammonia into the fluegas and subsequent reduction of NO_x. Two available technologies are thermal $DeNO_x$ and the NO_xOUT process.

Thermal $DeNO_x$--Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high-temperature SNCR of NO_x, using ammonia as the reducing agent. Thermal $DeNO_x$ requires the fluegas temperature to be a relatively narrow range (1800°F +/- 100°F). The limiting phenomenon is the injection of ammonia in the optimum boiler locations so as to achieve maximum ammonia/NO_x mixing within the desired temperature window, consistent with normal boiler operation. This requires boiler temperature profile mapping as a function of load.

Anhydrous ammonia is a toxic chemical which has the potential to be accidentally released. The handling of this chemical would require stringent safety precautions and procedures, as well as additional facilities.

NO_xOUT Process--The NO_xOUT process originated from research by the Electric Power Research Institute (EPRI) on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc. for commercialization. In the NO_xOUT process, aqueous urea is injected into the fluegas stream ideally within a temperature range of 1600°F to 1900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/_2\, O_2 \text{ --> } 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. The potential advantages of the system over Thermal $DeNO_x$ is lower capital and operating costs of urea injection, and use of a nontoxic and nonhazardous reactant.

Potential disadvantages of the system are formation of ammonia from excess urea treatment and sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold-end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases. For either SNCR process, the gas residence time is important. The suggested residence time for SNCR is about 0.5 to 1 second.

There are no proven applications of SNCR technology for bagasse combustion, but the Thermal $DeNO_x$ process has been applied to industrial boilers. Thus SNCR is deemed technically feasible for bagasse combustors with a NO_x control efficiency of 40%, based on FDEP's recent final determination for a bagasse cogeneration boiler.

Selective Catalytic Reduction

The SCR process uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600-750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 \text{ -> } 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 \text{ -> } 3N_2 + 6H_2O$$

The SCR equipment in an oil-fired boiler would have to be placed between the economizer and air preheater to achieve proper temperature conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

Although the operating experience on oil-fired boilers is limited, certain cost, technical, and environmental considerations have surfaced. Most of these considerations were discussed in the preceding section under SNCR, which has similar considerations. Ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the air preheater and flue surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter; although the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from carbonaceous fuels also could form ammonium salts.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°-950°F, have been available commercially only recently. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800-900°F. At temperatures of 1000°F and above, the zeolite catalyst will be irreparably damaged. The fibrous and moisture-laden nature of particulate matter generated by bagasse boilers would likely cause blockage in the catalyst. Even with large pore openings, particulate would likely adhere to catalyst sites and render the catalyst ineffective. In addition, it may not be possible to achieve the desired fluegas temperature without reheating because exhaust temperatures of bagasse boilers are relatively low (500-600°F).

There are no applications of SCR on bagasse boilers. Based on this and the complex problems associated with applying a catalyst bed to this type of combustor, the applicability of this technology is unknown. Therefore SCR is judged infeasible for this application.

5.3.2 Evaluation of Technically Feasible NO_x Control Methods

5.3.2.1 Ranking of Feasible Control Technologies

A baseline emission level must be established as the basis for top-down BACT ranking and for economic analysis purposes. The baseline is defined as the uncontrolled emission rate of the process being reviewed. For the impact analysis, the uncontrolled NO_x emission rate was estimated to be 0.26 lb/MM Btu based on bagasse combustion. This is the emission rate that bagasse boiler manufacturers have expressed a willingness to guarantee.

As discussed previously, FDEP has determined that SNCR can achieve a NO_x removal efficiency of 40% for a bagasse cogeneration boiler. FGR can potentially achieve an NO_x removal efficiency of up to 40%, but 30% was assumed as a more conservative approach for this unproven application.

LNB can achieve an NO_x removal efficiency of 30-60% (for fuel oil combustion only), but 45% was used as a conservative estimate for this analysis. Low-nitrogen fuel oil can achieve 25-50% reduction in fuel-bound NO_x (for fuel oil combustion only), but 35% was used as a conservative estimate. OFA can achieve an NO_x removal efficiency of 10-30% but 0% was used for this analysis, as it is an inherent part of the combustor design, and thus is part of the baseline emission.

Therefore, the BACT top-down hierarchy ranks SNCR first, FGR second, LNB third and low-nitrogen fuel oil fourth.

5.3.2.2 Analysis of Control Technology Impacts

Technical Issues

Of the combustion modification techniques, only OFA is currently used for bagasse and is integral to the design of bagasse-fired boilers. This technology is one of the likely reasons for the relatively low NO_x emissions exhibited from these boilers. Additional overfire air would not likely reduce NO_x emissions significantly from current levels. LNB technology is not currently used nor is this technology applicable to bagasse combustion due to the nature of the fuel and existing burning methods. LNB can be applied to fuel oil combustion, however. FGR, while potentially applicable to bagasse-fired boilers, has not been applied and its effectiveness for NO_x reduction is questionable.

SNCR and SCR, the post-combustion control technologies, have not been applied to bagasse-fired boilers. The application of SNCR, although possible, would be extremely difficult to implement, because the required temperature zones for reaction will spatially vary within a bagasse boiler as a function of boiler load. This variability, coupled with the relatively small boiler space make the overall technical feasibility of SNCR questionable. Other technical issues related to SNCR include:

- Ammonia/urea distribution: NH_3 must be uniformly distributed in the exhaust stream to ensure optimum mixing with NO_x in the narrow temperature window.

- Temperature profile: the narrow temperature range that SNCR systems operate within (i.e., about 100°F) must be maintained even during load changes.

- Ammonia/urea control: a molar ratio of at least 1:1 NH_3 to NO_x generally is needed to ensure high removal efficiencies. The quantity of NH_3 introduced must be carefully controlled: with too little NH_3, the desired control efficiency is not reached; with too much NH_3, emissions of NH_3 (referred to as "slip") can occur.

- Gas residence time: residence time of the combustion gas after ammonia/urea injection must be within a narrow range to ensure satisfactory removal efficiency.

- Special storage and handling equipment are required for ammonia/urea.

Environmental Effects

SNCR has several environmental effects which should be considered:

- Ammonia slip: NH_3 slip (NH_3 that passes unreacted into the atmosphere) can occur if:

  - Too much ammonia/urea is added
  - NH_3 distribution is not uniform
  - The velocity is not within the optimum range
  - The proper temperature is not maintained

- Ammonium salts: ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can form when firing oil or bagasse, and are emitted as particulates.

- Transportation and storage: storage and handling of urea poses additional environmental risks. Appropriate contingency plans and controls in the event of a release are required.

There are no significant environmental issues associated with FGR, LNB, or low-nitrogen fuel oil.

Energy Requirements

Additional energy will be required to operate ammonia/urea pumps and dilution air fans (100 kw) for SNCR. There will also be additional energy requirements associated with the large FGR fan (428 kw).

Economic Analysis

An economic analysis of the control alternatives is presented in Table 5-6. This table shows that the TCI of SNCR applied to this bagasse boiler would be at least $2.18 MM, and the AC would be $990,119/yr. The economic analysis also shows that the TCI of FGR applied to this bagasse boiler would be at least $0.9 MM and the AC of FGR would be at least $652,368/yr. The analysis also establishes that the TCI of LNB applied to this bagasse boiler would be at least $229,770 and the AC would be $59,921/yr. The TCI for low-nitrogen fuel oil is $585,769,000 and the AC is $786,693/yr.

Table 5–6. Cost Analysis for NOx Emissions Control

Cost Items	Cost Factors	SNCR	FGR	LNB	Low–N Oil
DIRECT CAPITAL COSTS (DCC)					
(1) Purchased Equipment Cost:					
(a) Basic Equipment/Services	Vendor Quotation	$1,104,859	$375,000	$90,000	$173,250
(b) Auxilary Equipment	Vendor Quote (included in 1a)	$0	$0	$0	$15,750
(c) Instrumentation & Controls	0.10(1a + 1B)	Included	Included	Included	$18,900
(d) Modification to Other Equipment	None	$0	$0	$0	$0
(e) Freight*	0.05(1a + 1b + 1c + 1d)	$55,243	$18,750	$4,500	$10,395
(f) Florida Sales Tax*	0.06(1a + 1b + 1c + 1d)	$66,292	$22,500	$5,400	$12,474
(g) Purchased Equipment Subtotal	(1a + 1b + 1c + 1d + 1e + 1f)	$1,226,393	$416,250	$99,900	$230,769
(2) Direct Installation Cost*	SNCR: 0.3(1g); others: 0.67(1g)	$367,918	$278,888	$66,933	$154,615
Total DCC	(1g + 2)	$1,594,312	$695,138	$166,833	$385,384
INDIRECT CAPITAL COSTS (ICC)					
(3) Indirect Installation Cost:					
(a) Technology License Fee	Vendor Quote (included in 1a)	$0	$0	$0	$0
(b) Engineering & Supervision *	SNCR: vendor quote; others 0.20(1g)	$247,597	$83,250	$19,980	$46,154
(c) Construction & Field Expenses *	SNCR: vendor quote; others 0.20(1g)	Included	$83,250	$19,980	$46,154
(d) Construction & Contractor Fee *	0.10(1g)	$122,639	$41,625	$9,990	$23,077
(e) Contingencies *	0.10(1g)	$122,639	$41,625	$9,990	$23,077
(4) Other Indirect Cost:					
(a) Start–up & Testing *	SNCR: vendor quote; others 0.03(1g)	$71,182	$12,488	$2,997	$6,923
(b) Model Study	Vendor Quote (included in 1a)	$0	$0	$0	$0
(c) Working Capital	(7b+7c)/12	$24,645	$0	$0	$55,000
Total ICC	(3) + (4)	$588,702	$262,238	$62,937	$200,384
TOTAL CAPITAL INVESTMENT (TCI)	DCC + ICC	$2,183,014	$957,375	$229,770	$585,769
DIRECT OPERATING COST (DOC)					
(5) Operating Labor:					
(a) Operator	8,760 hr/yr @ $17/hr * 3/8	$55,845	$55,845	$0	$0
(b) Supervisor*	15% of operator cost	$8,377	$8,377	$0	$0
(6) Maintenance Labor and Materials*	0.05(1g)	$79,716	$34,757	$8,342	$19,269
(7) Utilities					
(a) Electrical	31–428kw @ $0.08/kw–hr	$21,585	$299,942	$0	$0
(b) Ammonia (urea)	$0.80/gal * 369,762 gal	$295,738	$0	$0	$0
(c) Oil price differential	$0.22/gallon premium	$0	$0	$0	$660,000
Total DOC	(5) + (6) + (7)	$461,260	$398,921	$8,342	$679,269
INDIRECT OPERATING COST (IOC)					
(8) Overhead *	60% of (5) and (6)	$86,362	$59,387	$5,005	$11,562
(9) Property Taxes *	1% of TCI	$21,830	$9,574	$2,298	$5,858
(10) Insurance *	1% of TCI	$21,830	$9,574	$2,298	$5,858
(11) Administration *	2% of TCI	$43,660	$19,148	$4,595	$11,715
Total IOC	(8) + (9) + (10) + (11)	$173,683	$97,682	$14,196	$34,992
TOTAL OPERATING COST (TOC)	DOC + IOC	$634,943	$496,603	$22,537	$714,261
CAPITAL RECOVERY COST (CRC)	0.1627(TCI)	$355,176	$155,765	$37,384	$95,305
ANNUALIZED COST (AC)	TOC + CRC	$990,119	$652,368	$59,921	$809,566

Notes:
* Indicates that the cost factors are based on EPA's OAQPS Control Cost Manual, Fourth Edition (1990) – Chapter 6.

5.3.3 BACT Analysis Summary for NO_x

The top-down BACT analysis for NO_x for the proposed boiler firing bagasse and oil as the auxiliary fuel is summarized in Table 5-7. The ACE values are $4,412, $3,876, $534, and $9,621 per ton of NO_x removed for the SNCR, FGR, LNB and low-nitrogen oil, respectively. The ICE values are $6,021, $10,561 $-26,725 and $9,621 per ton of NO_x removed for the SNCR, FGR, LNB and low-nitrogen oil, respectively. The ACE and ICE values for SNCR and FGR are excesive, therefore **using low-nitrogen oil represents BACT for NO_x emissions for the proposed boiler No. 7.** The proposed NO_x BACT limit for boiler No. 7 is as follows:

- Bagasse-firing: 0.26 lb/MM Btu
- Oil-firing: 0.1-0.2 lb/MM Btu (low to high heat release)

5.4 BACT EVALUATION FOR CO AND VOC EMISSIONS

In this section, the available control technologies capable of reducing CO and VOC emissions produced from firing bagasse and fuel oil will be identified and evaluated. Potential application of these technologies as BACT for the proposed spreader-stoker boiler, rated on oil at 255 MM Btu/hr, is discussed. Table 5-8 is a summary of the potential CO and VOC control technologies presented in this section.

The EPA BACT/LAER clearinghouse has no BACT determinations for CO or VOC emission from bagasse combustors or oil combustion in boilers. Historically, BACT and LAER emission limits for CO and VOC on bagasse and oil-fired boilers have been based on the use of good combustion practices, rather than add-on control systems.

In bagasse-fired boilers, the fuel characteristics and the combustion practices result in CO and VOC emissions that are somewhat high, relative to fossil-fuel fired boilers. The use of FGR could theoretically reduce CO and VOC emissions by reburning a portion of the VOCs in the recirculated exhaust. The overall effectiveness of fluegas recirculation would be limited because:

- The extremely high particulate loading of the combustion gas and the abrasive nature of the flyash would make this system very unreliable

- This has never been applied to a bagasse combustor

- This technology would not be economically feasible, per the analysis done for NO_x control

TABLE 5-7. SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS FOR NOx

FEASIBLE CONTROL TECHNOLOGY	REMOVAL EFFICIENCY	CONTROLLED EMISSIONS TPY	EMISSION REDUCTION TPY (a)	AC $/YR	ACE $/Ton	ICE $/Ton	IEI MW-hr	TOXICS IMPACT?	AEI?
SNCR	40%	336.6	224.4	990,119	4,412	6,021	876	Yes	Yes
FGR	30%	392.7	168.3	652,368	3,876	10,561	3,749	No	No
Low-NOx burner	20%	448.8	112.2	59,921	534	(26,725)	0	No	No
Low-nitrogen oil	15%	476.9	84.2	809,566	9,621	9,621	0	No	No
Baseline	0%	561.0	0	0	0	0	0	No	Yes

(a). Emissions reduction over baseline level of no controls. NOx baseline emissions derived from bagasse boiler vendor guarantee.

Table 5-8

Summary of Potential CO and VOC control Technologies[1]

Control Technology	Typical Effic. (% CO)	Typical Effic. (% VOC)	In Service On Bagasse Combustors?	In Service On Other Combustion Sources?	Technically Feasible For This Combustor?
Direct-flame Oxidation	90-99	90-99	No	Yes	No[2]
Catalytic Oxidation	90-95	90-95	No	Yes	No[3]
Fluegas Recirculation	30-50%	30-50%	No	No	Yes[4]
Good Combustion Practices	15-50	15-50	Yes	Yes	Yes

Notes:

[1] Source: Air Pollution Engineering Manual, AWMA, 1992.

[2] Abrasive Particulate loading to high in combustor.

[3] Same as above.

[4] See discussion under NO_x control.

Table 5-8
Summary of Potential CO and VOC control Technologies[1]

Control Technology	Typical Effic. (% CO)	Typical Effic. (% VOC)	In Service On Bagasse Combustors?	In Service On Other Combustion Sources?	Technically Feasible For This Combustor?
Direct-flame Oxidation	90-99	90-99	No	Yes	No[2]
Catalytic Oxidation	90-95	90-95	No	Yes	No[3]
Fluegas Recirculation	30-50%	30-50%	No	No	Yes[4]
Good Combustion Practices	15-50	15-50	Yes	Yes	Yes

Notes:
[1] Source: Air Pollution Engineering Manual, AWMA, 1992.
[2] Abrasive Particulate loading to high in combustor.
[3] Same as above.
[4] See discussion under NO_x control.

Post-combustion VOC controls have not been applied to bagasse-fired boilers. Such common techniques as direct-flame incineration, catalytic oxidation, and carbon absorption are also inappropriate technologies for bagasse boilers for the same reasons as above. The only technically feasible CO and VOC control technology for bagasse-fired boilers is good combustion practices.

Because of their utility in reducing CO and VOC emissions, along with its success record in the sugar industry, **good combustion practices are proposed as BACT for emissions for the proposed boiler No. 7 when firing bagasse or oil.**

For the proposed boiler No. 7, the most appropriate BACT precedent for VOC, CO and NO_x appears to be the permit for Clewiston boiler No. 4, which relies on the inherent design features of the bagasse boiler along with the appropriate operating procedures to ensure that emission will be maintained at the lowest possible level. That permit imposes no requirement for add-on control technology, and that is the approach recommended here for the U.S. Sugar Corporation Clewiston mill boiler No. 7.

5.5 BACT EVALUATION FOR SULFURIC ACID MIST EMISSIONS

Sulfuric acid mist is generated from the emissions of SO_3 when oil is combusted. Sulfur trioxide can further react with water present in the fluegas to form sulfuric acid mist. The control of acid gas emissions is primarily controlled by removing the precursor pollutants from the fluegas with either wet or semi-dry scrubbing processes or by reducing the pollutant formation by firing low-sulfur fuel oil. Sulfuric acid mist emissions will be therefore be controlled through the use of low-sulfur fuel oil for SO_2 emissions from oil combustion.

5.6 BACT EVALUATION FOR BERYLLIUM EMISSIONS

Beryllium emissions were estimated using EPA factors for fuel oil combustion and assuming no removal in the scrubbing system, as there are no published factors for beryllium removal efficiency in the scrubber. Beryllium emissions are primarily controlled by removing the gaseous or particulate metal from the fluegas with PM control equipment. Beryllium emissions will be therefore be controlled for this project by installation of an ESP for PM emissions.

ATTACHMENT "C"

Table 2-8
Proposed Emission Limits (lb/MM Btu) for Boiler No. 7

Pollutant	Bagasse	No. 6 Oil
Particulate (TSP)	0.03	0.03
Particulate (PM10)	0.03	0.03
Sulfur Dioxide	0.167	0.05[1]
Nitrogen Oxides	0.26	0.1-0.2[2]
Carbon Monoxide	0.35	0.066
Volatile Organic Compounds	0.21	0.004
Lead	--	56E-06
Mercury	--	6.4E-06
Beryllium	--	8.4E-06
Fluorides	--	12.6E-06
Sulfuric Acid Mist	0.0167	0.05

Notes:

[1] Compliance based on use of very-low-sulfur fuel oil and on 24-hour rolling average per 40 CFR 60, Subpart Db.

[2] Range represents low to high heat-release rate. Compliance based on use of low-nitrogen fuel oil and on 24-hour rolling average per 40 CFR 60, Subpart Db.

Table 3-3
PSD Source Applicability Analysis for Clewiston Boiler No. 7

Regulated Pollutant	Baseline[1] Emissions (TPY)	Boilers No. 1-4 and 7 Proposed Project Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies
Particulate (TSP)	750	759	9	25	No
Particulate (PM10)	750	759	9	15	No
Sulfur Dioxide	366	699	333	40	Yes
Nitrogen Oxides	709	1,070	361	40	Yes
Carbon Monoxide	28,425	29,020	595	100	Yes
VOC	837	1,157	320	40	Yes
Lead	0.00058	0.00683	0.00625	0.6	No
Mercury	0.00007	0.00078	0.00071	0.1	No
Beryllium	0.00009	0.00102	0.00093	0.0004	Yes
Fluorides	0.00013	0.00153	0.00140	3	No
Sulfuric Acid Mist	37	70	33	7	Yes
Total Reduced Sulfur	--	--	0	10	No
Asbestos	--	--	0	0.007	No
Vinyl Chloride	--	--	0	0	No

[1] See Attachment H for the derivation of baseline emissions.

TABLE 2-3. CLEWISTON MILL POTENTIAL ANNUAL EMISSIONS (TON/YEAR)

FUEL OIL COMBUSTION

	Avg. MMBtu/hr	Day/yr	Mgal/yr	PM TPY	SO2 TPY	NOx TPY	CO TPY	VOC TPY
Boiler No.1	3.49	160	89.23	0.67	17.51	2.45	0.22	0.01
Boiler No.2	3.38	160	86.51	0.65	16.98	2.38	0.22	0.01
Boiler No.3	1.91	160	48.97	0.37	9.61	1.35	0.12	0.01
Boiler No.4	1.93	160	49.33	0.37	5.81	1.36	0.12	0.01
Boiler No.7	0	0	0	0.00	0.00	0.00	0.00	0.00
Total			274	2.1	49.9	7.5	0.7	0.0

BAGASSE COMBUSTION

	Avg. MMBtu/hr	Day/yr	Wet Feed TPY	PM TPY	SO2 TPY	NOx TPY	CO TPY	VOC TPY
Boiler No.1	415	160	199,054	199.1	49.8	119.4	7,166	199.1
Boiler No.2	402	160	192,982	193.0	48.2	115.8	6,947	193.0
Boiler No.3	220	160	105,569	126.7	26.4	63.3	3,800	105.6
Boiler No.4	603	160	289,384	173.6	192.2	346.9	10,418	246.0
Boiler No.7	738	365	808,110	97.0	539.8	840.4	1,131	686.9
Total			1,595,098	789	856	1,486	29,463	1,430

TOTAL COMBUSTION EMISSIONS

	Avg. MMBtu/hr	PM TPY	SO2 TPY	NOx TPY	CO TPY	VOC TPY
Boiler No.1	418	200	67	122	7,166	199
Boiler No.2	405	194	65	118	6,948	193
Boiler No.3	222	127	36	65	3,801	106
Boiler No.4	605	174	198	348	10,418	246
Boiler No.7	738	97	540	840	1,131	687
Total		791	906	1,493	29,464	1,431

Filename: Tbl2_3x.wk3 27-Jul-94

TABLE 2-4. CLEWISTON MILL POTENTIAL EMISSIONS, 24-hour case

Fuel Oil Combustion

	MMBtu/hr	Mgal/hr	PM Lb/hr	SO2 Lb/hr	NOx Lb/hr	CO Lb/hr	VOC Lb/hr	Steam Lb/hr
Boiler No.1	103.5	0.69	10.4	270.8	38.0	3.45	0.19	72,000
Boiler No.2	94.5	0.63	9.5	247.3	34.7	3.15	0.18	65,739
Boiler No.3	57.0	0.38	5.7	149.2	20.9	1.90	0.11	41,044
Boiler No.4	0.0	0.00	0.0	0.0	0.0	0.00	0.00	0
Boiler No.7	0.0	0.00	0.0	0.0	0.0	0.00	0.00	0
Total		**1.70**	**25.5**	**667.3**	**93.5**	**8.50**	**0.48**	**178,783**

Bagasse Combustion

	MMBtu/hr	Ton/hr	PM Lb/hr	SO2 Lb/hr	NOx Lb/hr	CO Lb/hr	VOC Lb/hr	Steam Lb/hr
Boiler No.1	341	42.6	85.2	21.3	51.1	3,067	85.2	163,000
Boiler No.2	354	44.2	88.5	22.1	53.1	3,185	88.5	169,261
Boiler No.3	190	23.7	56.9	11.9	28.5	1,708	47.4	93,956
Boiler No.4	707	88.3	106.0	117.3	180.7	6,359	150.2	335,000
Boiler No.7	738	92.3	22.1	122.5	147.6	258	156.9	350,000
Total		**291**	**359**	**295**	**461**	**14,578**	**528**	**1,111,217**

Total Hourly Emissions

	MMBtu/hr		PM Lb/hr	SO2 Lb/hr	NOx Lb/hr	CO Lb/hr	VOC Lb/hr	Steam Lb/hr
Boiler No.1	444		96	292	89	3,071	85	235,000
Boiler No.2	448		98	269	88	3,188	89	235,000
Boiler No.3	247		63	161	49	1,710	48	135,000
Boiler No.4	707		106	117	181	6,359	150	335,000
Boiler No.7	738		22	123	148	258	157	350,000
Total			**384**	**962**	**555**	**14,587**	**529**	**1,290,000**

TABLE 2–5. CLEWISTON MILL POTENTIAL EMISSIONS, 3–hour case

Fuel Oil Combustion

	MMBtu/hr	Mgal/hr	PM Lb/hr	SO2 Lb/hr	NOx Lb/hr	CO Lb/hr	VOC Lb/hr	Steam Lb/hr
Boiler No.1	122.3	0.82	12.2	320.0	44.8	4.08	0.23	85,078
Boiler No.2	120.0	0.80	12.0	314.0	44.0	4.00	0.22	83,478
Boiler No.3	72.8	0.49	7.3	190.5	26.7	2.43	0.14	52,421
Boiler No.4	0.0	0.00	0.0	0.0	0.0	0.00	0.00	0
Boiler No.7	0.0	0.00	0.0	0.0	0.0	0.00	0.00	0
Total	**315.1**	**2.10**	**31.5**	**824.5**	**115.5**	**10.50**	**0.59**	**220,978**

Bagasse Combustion

	MMBtu/hr	Ton/hr	PM Lb/hr	SO2 Lb/hr	NOx Lb/hr	CO Lb/hr	VOC Lb/hr	Steam Lb/hr
Boiler No.1	313	39.2	78.4	19.6	47.0	2,821	78.4	149,922
Boiler No.2	317	39.6	79.2	19.8	47.5	2,851	79.2	151,521
Boiler No.3	167	20.9	50.0	10.4	25.0	1,501	41.7	82,579
Boiler No.4	707	88.3	106.0	117.3	192.4	6,359	150.2	335,000
Boiler No.7	738	92.3	22.1	123.3	191.9	258	156.9	350,000
Total		**280**	**336**	**290**	**504**	**13,792**	**506**	**1,069,021**

Total Hourly Emissions:

	MMBtu/hr	PM Lb/hr	SO2 Lb/hr	NOx Lb/hr	CO Lb/hr	VOC Lb/hr	Steam Lb/hr
Boiler No.1	436	91	340	92	2,825	79	235,000
Boiler No.2	437	91	334	92	2,855	79	235,000
Boiler No.3	240	57	201	52	1,504	42	135,000
Boiler No.4	707	106	117	192	6,359	150	335,000
Boiler No.7	738	22	123	192	258	157	350,000
Total		**367**	**1,115**	**619**	**13,802**	**507**	**1,289,999**

BRYAN CAVE

ST. LOUIS, MISSOURI
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PHOENIX, ARIZONA
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ROBERT F. VAN VOORHEES
DIRECT DIAL NUMBER
(202) 508-6014

June 7, 1994

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: U.S. Sugar Corporation, Clewiston Mill
Boiler No. 7 - AC 26-238006 & PSD-FL-208

Dear Mr. Brown:

This letter responds to your letter dated March 18, 1994, requesting additional information to complete review of our pending application for a permit to construct Boiler No. 7 at the Clewiston Mill in Hendry County, Florida. Since receiving your letter and since the meeting with you and your staff on March 28, 1994, we have conducted detailed discussions with additional potential boiler manufacturers and air emissions control equipment vendors. Based on these discussions, United States Sugar Corporation (U.S. Sugar) provides the following additional information in response to your requests:

BACT DETERMINATION

Particulate Matter (PM):

1. Please provide the technical, economic and environmental analysis data for using an electrostatic precipitator (ESP) to control particulate matter emissions.

2. The Department has made contacts with several of the ESP's manufacturers that state that ESP technology is technically feasible for this project. Please explain the basis of your conclusion.

3. Provide a copy of the final ESP test report (include the wet ESP test data) for the tests conducted with United McGill Corporation Mobile Precipitator System in January 1994.

4. Provide a comparison of the design characteristic of the test ESP and ESPs used in other high conductivity ash applications. For example, an ESP was specified in the BACT determination to control particulate emissions from a circulating fluidized bed 338 MMBtu/hr boiler firing bagasse at the Puuene Mill, Hawaiian Commercial & Sugar Company, Limited. The emission limit when firing bagasse in the boiler was specified as 0.03 lb/MMBtu.

5. What is the maximum removal efficiency an ESP vendor will guarantee for Boiler No. 7?

RESPONSE TO ITEMS 1-5:

Although we still have serious concerns about the capability of this technology to operate on a bagasse boiler, U.S. Sugar is prepared, based on representations made to the company by control technology manufacturers and vendors, accept a determination that BACT for particulate matter for this boiler is an electrostatic precipitator (ESP) capable of achieving an emission limit of 0.03 lb/MMBtu for particulate matter when firing bagasse in the boiler.

Nitrogen Oxides (NO_x):

6. The equipment proposed appears to be consistent with other applications which utilize Selective Non Catalytic Reduction (SNCR). However, several costs appear to be either new or higher than other applications - namely the licensing fee, start-up and testing, the model study and annual operating costs. Provide a detailed cost analysis including a copy of the vendor quote for all equipment, tasks included in the performance test and justification for the annual operating labor cost. SNCR installation was specified in the BACT determination for the Puuene Mill boiler.

RESPONSE TO ITEM 6:

Based on the representations of boiler manufacturers, U.S. Sugar is prepared to accept a determination that BACT for this boiler is overfire air, high excess air rates, and good combustion practices capable of achieving an emission limit of 0.20 lb/MMBtu for nitrogen oxides when firing bagasse in the boiler. We have been assured that this emission level can be achieved without requiring the use of Selective Non Catalytic Reduction (SNCR) and without incurring the substantial additional costs associated with the installation and operation of that unit. In support of our cost analysis for the BACT demonstration, we are enclosing the vendor quote on the SNCR that you requested (Attachment A). We believe the information serves to confirm that the additional cost of an SNCR is unwarranted in light of the capability to achieve a level of 0.20 lb/MMBtu without the SNCR, and especially in light of the other environmental factors associated with the handling of urea in conjunction with the use of an SNCR, as described in our prior submissions.

Carbon Monoxide (CO):

7. The Department is taking into consideration the Boiler No. 4 stack test CO emission data. However, you need to evaluate the CO emission rates using the 0.35 lb/MMBtu standard (as in the Okeelanta Power Limited Partnership's permit).

   Your company and Okeelanta power are proposing good combustion practices as a control technology to reduce CO and VOC emissions. As such, we fail to understand your rationale for proposing the higher emission limit for this project. Your proposed CO emissions limit is 30 times higher than the Okeelanta project burning biomass fuel.

RESPONSE TO ITEM 7:

Based on the representations of boiler manufacturers, U.S. Sugar is prepared to accept a determination that BACT for carbon monoxide emissions from this boiler is good combustion practices and that the boiler will be capable of achieving an emission limit of 0.35 lb/MMBtu for carbon monoxide.

General

8. Submit appropriate updated tables (Tables 2-3, 2-4, 2-5, and 2-6) showing the revised emission limits for the affected pollutants.

RESPONSE TO ITEM 8:

Updated Tables 2-3, 2-4, and 2-5 are enclosed for your review (Attachments B, C, and D). We have concluded that it should be unnecessary to provide a revised version of Table 2-6 because the changes in BACT and the resulting emissions levels discussed with the Department and proposed in this letter would only serve to reduce the emission rates estimated in Table 2-6. Under the circumstances it seems unnecessary to go through the additional calculations to estimate more precisely the exact emission levels. We propose that you consider the Table 2-6 in the initial application as valid upper bound estimates of the emission levels. Thus, these estimates show -- with an even greater degree of certainty in light of the reduced emission rates -- that the FDEP no-threat limits (NTLs) for toxic air pollutants will not be exceeded by the proposed project.

Air Quality Related Values (AQRV)

9. On February 28, 1994, the Department sent you a letter with a copy of an AQRV survey for the Everglades National Park. This survey was done by the National Park Service (NPS). In order to complete your AQRV analysis, please review the survey, contact Des Morse of the NPS, coordinate with him any specific concerns the NPS may have with your AQRV analysis, and respond to these concerns, if any. Please provide the Department a copy of your response.

RESPONSE TO ITEM 9:

The requested information on Air Quality Related Values was submitted to you and to the National Park Service under separate cover by Peter Kroll of ICF Kaiser Engineers, Inc., on May 10, 1994.

This should provide all of the remaining information necessary to complete your review and approval of the construction permit application for Clewiston Boiler No. 7. We look forward to discussing with your staff on June 8, 1994 the steps necessary to complete your determinations and issuance of the necessary permits.

Sincerely,

Robert F. Van Voorhees

Robert F. Van Voorhees
Counsel for United States
Sugar Corporation

Enclosures

cc:	G. Preston Lewis, P.E.	- FDEP
	Douglas G. Outlaw, P.E.	- FDEP
	Teresa M. Heron	- FDEP
	Cleve G. Holladay	- FDEP
	William H. Congdon, Esq.	- FDEP
	Murray Brinson	- U.S. Sugar
	Peter Barquin	- U.S. Sugar
	Peter Briggs	- U.S. Sugar
	Peter Kroll, P.E.	- ICF Kaiser

78708.01

ICF KAISER
ENVIRONMENT & ENERGY GROUP

ICF Kaiser Engineers, Inc.
Four Gateway Center
Pittsburgh, PA 15222-1207
412/497-2000 Fax 412/497-2212

May 10, 1994

Mr. John C. Brown, Jr., P.E.
Administrator, Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: US Sugar Corporation, Clewiston Mill
Boiler No. 7 - AC 26-238006 & PSD-FL-208

Dear Mr. Brown:

On behalf of the United States Sugar Corporation (US Sugar), we submit the following enclosed materials in response to the Department's March 18, 1994 request for additional information relating to US Sugar's application for a construction permit for Boiler No. 7 at its Clewiston Mill.

This letter provides our response to the Department's requests for information, item No. 9 related to Air Quality Related Values (AQRVs). We have revised Section 7.0, Additional Impact Analysis (submitted here as Attachment 1), of the PSD permit application in accordance with the Department's February 28 letter and the attached AQRV survey of the Everglades National Park (ENP) conducted by the National Park Service (NPS). We are also forwarding a copy of this directly to Dee Morse of the NPS. We have spoken to Dee Morse and believe that the information provided in this response will satisfy your needs and the needs of the NPS for additional information on this item.

Specifically, the analysis examines the maximum predicted cumulative concentrations of pollutants due to the proposed boiler and other proposed and existing sources and concludes that these concentrations will remain well below levels that could be expected to affect sensitive resources in the ENP. Moreover, as noted in our December 22, 1993 response, the proposed US Sugar boiler No. 7 does not contribute a significant portion (less than 1% of the total) to the ENP Class I receptor with the highest-second-highest SO_2 impact for any of the five years of meteorological data used in the impact analysis. Thus the concentrations resulting from the cumulative effect of all sources are well below levels that might be expected to cause effects, and the relative contribution of the proposed boiler No. 7 to even those concentrations would be minute.

Please contact me at (412) 497-2024 or Bob Van Voorhees at (202) 508-6014 if you have any questions about the information provided in this response. We look forward to working with you and your staff to assist in your review and approval of this permit application.

Very truly yours,

Peter J. Kroll

Peter J. Kroll, P.E.
Manager, Air Quality Engineering

cc: G. Preston Lewis P.E, FDEP
Douglas G. Outlaw, P.E., FDEP
Teresa M. Heron, FDEP
Cleve G. Holladay, FDEP
Claire E. Lardner, Esq., FDEP
Dee Morse, NPS
Murray Brinson, US Sugar
Peter Barquin, US Sugar
Peter Briggs, US Sugar
Robert Van Voorhees, Esq., Bryan Cave

Enclosure

ATTACHMENT A

Research-Cottrell
Air Pollution Control Division

April 6, 1994

Mr. Dave Beranek
ICF Kaiser Engineers, Inc.
Four Gateway Center
Pittsburgh, PA 15222-1207

Fax: (412) 497-2212

RE: United States Sugar SNCR Study

Dear Dave:

Thank you for providing Research-Cottrell the opportunity to provide budgetary estimates for supply of SNCR to United States Sugar Boiler No. 7.

I have attached budgetary pricing and process and economics calculations for SNCR NOx Control. The O & M costs assume a cost of electricity of 5 cents/KWhr.

We strongly recommend that temperature measurements be taken on any units where US Sugar is seriously considering the use of this technology. Without temperature data, it is not possible to design an SNCR system for predictable performance with any confidence. Research-Cottrell has its own temperature mapping team that has tested utility and industrial boilers for the purpose of design of SNCR systems.

Items that could vary significantly from the assumptions we have made and thereby impact the estimated costs are: the number of injectors and the type of injectors, the number of units at a site equipped with the technology, and the availability of DCS for control. With the temperature data, a more accurate estimate of the injector configuration can be made. If several units at US Sugar use the technology, significant savings in installation costs can be realized.

We recommend urea-based NOxOUT technology for these units. The budgetary estimates include the following:

1. Factory assembled and tested, skid-mounted pumping systems, to include one circulation module, and one metering/mixing module. The modular pump skids come with their own built-in control panels that allow local manual or remote control. The modules supplied have complete redundancy of pumps, enabling service of the pumps with the system in operation. The control panels contain all motor starters.

2. Distribution panels to control and monitor flow rate of reagent and atomizing/cooling air to the injectors.

3. Wall injectors, estimated as necessary for the system. It is assumed that wall injectors will be adequate. Injectors are of a proprietary design to properly distribute the reagent into the boiler gases. If it is determined that in-furnace injectors are needed, costs will be higher.

4. Retraction mechanisms on the first level of injection. The retraction mechanisms automatically retract injectors at high loads or upon loss of atomization/cooling air or system shutdown.

5. A site license that authorizes the user to utilize the technology and to purchase any future improvements in NOxOUT technology that may be developed by Research-Cottrell or Nalco Fuel Tech. The site license fee included in the price is a one-time fee that does not require any future updating.

6. Automatic control by Programmable Logic Controller. For plants with Distributed Control Systems (DCS), control can be from the DCS. In this case savings can be realized by elimination of the PLC, the associated PC interface and associated programming.

7. Reagent storage for about 2 weeks continuous operation.

8. Estimated installation and materials, not to include boiler penetrations.

9. All engineering, documentation, and project management.

10. Startup and guarantees.

Mr. Dave Beranek
Page Three
April 6, 1994

Items not included in this proposal:

1. Continuous Emission Monitoring System.

2. Any additional boiler penetrations that may be needed for installation of injectors. For wall injectors, sight ports can be used. When sight ports are not available and tube-wall webbing is less than 1 inch, it may be necessary to bend one boiler wall tube.

3. Taxes, Duties, etc.

SNCR can be a very cost effective means of controlling NOx on boilers. Research-Cottrell benefits from the experience of supplying SNCR technology, both NOxOUT and Thermal DeNOx, on over forty facilities. Research-Cottrell also benefits from the experience of its technology licensors, Nalco Fuel Tech (NOxOUT), Exxon Research and Engineering Company (Thermal DeNOx), and Ontario Hydro International (SONOX - combined NOx and SO_2 control). No other supplier of SNCR technology can claim this.

Should you have any questions, please feel free to call me at (908) 685-4481.

Sincerely,

Victor Ciarlante

Victor Ciarlante
Applications Engineer

VC:jm

cc: J. E. Staudt

NOxOUT Chemical Flowrate Calculation

US Sugar, Boiler No. 7

---------PROCESS---------

Flue Gas Conditions		MW,wet	26.82 #/#mole	Flue Gas (metric)	
Massflo, dry	431,759	CO_2	15%		
Massflo, wet	582,712	Press (psia)	14.7		
%vol H_2O	38.6%				
Mol Wt., dry	32.37	Reduction (%)	55%	Nm^3/hr	110,468
SCFM (dry)	71,270	Util. (30-40%)	35%		
Meas NOx (ppm)	386	Temp (F)	750	Temp (C)	399
Meas Oxy	5.4%	ACFM	265,000	M^3/hr	442,441
Cor. Oxy	6.0%			MWth	216
Cor. NOx	371 ppm				
SCFM dry, stoich (apprx)	52,787				
excess air	35.0%				
MMBTU/hr	738	#NO_2/MMBTU in	0.26		
		#NO_2/MMBTU out	0.12		

Results

#/hr NO_2 in	192.4		inlet kg/hr NO_2	87.4
NSR	1.6		inlet mg/Nm^3 NO_2	791
#/hr urea	197.2		kg/hr urea	89.5
gph NOxOUT	42.2		l/hr NOxOUT	159.8
Outlet NOx	174 ppm	(act)	outlet kg/hr NO_2	39.3
Outlet NOx	167	(cor)	outlet mg/Nm^3 NO_2	356
#/hr NO_2 out	86.6 #/hr			

---------ECONOMICS---------

NOxOUT A price	0.8 $/gal
Cap. Factor	80%
Yearly Reagent	$236,747
O&M $/ton NO_2	$640
Capacity	738 MMBTU/hr
Cap. Cst	$1,929 /MMBTU/hr
Capital Cost	$1,423,639
Captl Rec Fctr	0.15
Annual Cap	$213,546
	annualized capital plus O&M
Capacity Facto	80%
$/ton NO_2	$1,216

			from	to
EQUIPMENT # of item		Dil. Wtr. Flw	5.3	39.3 gpm
Storage/Tnk	1	Urea Conc.	6%	1%
Circ. Module	1			
Metering Modul	1	Air (max)	160 SCFM	
Distr. Panel	4	Elect.- air co	25.7 KW (peak)	
Injectors	20	pumping, and	2.1 KW (avg)	
Inj. Retracts	6	heaters	3.0 KW(peak)	

Payments		
Engnrg	$247,597	$247,597
Mat'l	$1,104,859	$1,176,041
Accept	$71,182	
TOT	$1,423,639	$1,423,639

TABLE 2-3. CLEWISTON MILL POTENTIAL ANNUAL EMISSIONS (TON/YEAR)

FUEL OIL COMBUSTION

	Avg. MMBtu/hr	Day/yr	Mgal/yr	PM	SO2	NOx	CO	VOC
Boiler No.1	3.49	160	89.23	0.67	17.51	2.45	0.22	0.01
Boiler No.2	3.38	160	86.51	0.65	16.98	2.38	0.22	0.01
Boiler No.3	1.91	160	48.97	0.37	9.61	1.35	0.12	0.01
Boiler No.4	1.93	160	49.33	0.37	5.81	1.36	0.12	0.01
Boiler No.7 crop	2.01	160	51.54	0.12	0.18	0.52	0.13	0.01
Boiler No.7 off	255	69	2,810	6.32	9.98	28.10	7.03	0.28
Total TPY			3,136	8.5	60.1	36.2	7.8	0.3

BAGASSE COMBUSTION

	Avg. MMBtu/hr	Day/yr	Wet Feed TPY	PM	SO2	NOx	CO	VOC
Boiler No.1	415	160	199,054	199.1	49.8	119.4	7,166	199.1
Boiler No.2	402	160	192,982	193.0	48.2	115.8	6,947	193.0
Boiler No.3	220	160	105,569	126.7	26.4	63.3	3,800	105.6
Boiler No.4	603	160	289,384	173.6	192.2	346.9	10,418	246.0
Boiler No.7 crop	630	160	302,341	36.3	200.8	241.9	423	257.0
Boiler No.7 off	450	136	183,564	22.0	121.9	146.9	257	156.0
Total TPY			1,272,894	751	639	1,034	29,012	1,157

TOTAL COMBUSTION EMISSIONS

	Avg. MMBtu/hr	PM	SO2	NOx	CO	VOC
Boiler No.1	418	200	67	122	7,166	199
Boiler No.2	405	194	65	118	6,948	193
Boiler No.3	222	127	36	65	3,801	106
Boiler No.4	605	174	198	348	10,418	246
Boiler No.7	493	65	333	417	687	413
Total TPY		759	699	1,070	29,020	1,157

TABLE 2-4. CLEWISTON MILL POTENTIAL EMISSIONS, 24-hour case

Fuel Oil Combustion

	MMBtu/hr Avg.	Day/yr	Mgal/yr	PM	SO2	NOx	CO	VOC	Steam Lb/hr
Boiler No.1	103.5		0.69	10.4	270.8	38.0	3.45	0.19	72,000
Boiler No.2	94.5		0.63	9.5	247.3	34.7	3.15	0.18	65,739
Boiler No.3	57.0		0.38	5.7	149.2	20.9	1.90	0.11	41,044
Boiler No.4	0.0		0.00	0.0	0.0	0.0	0.00	0.00	0
Boiler No.7	0.0		0.00	0.0	0.0	0.0	0.00	0.00	0
Total lb/hr			**1.70**	**25.5**	**667.3**	**93.5**	**8.50**	**0.48**	**178,783**

Bagasse Combustion

	MMBtu/hr Avg.	Day/yr	Mgal/yr	PM	SO2	NOx	CO	VOC	Steam Lb/hr
Boiler No.1	341		42.6	85.2	21.3	51.1	3,067	85.2	163,000
Boiler No.2	354		44.2	88.5	22.1	53.1	3,185	88.5	169,261
Boiler No.3	190		23.7	56.9	11.9	28.5	1,708	47.4	93,956
Boiler No.4	707		88.3	106.0	117.3	180.7	6,359	150.2	335,000
Boiler No.7	738		92.3	22.1	122.5	147.6	258	156.9	350,000
Total lb/hr			**291**	**359**	**295**	**461**	**14,578**	**528**	**1,111,217**

Total Hourly Emissions

	MMBtu/hr Avg.		PM	SO2	NOx	CO	VOC	Steam Lb/hr
Boiler No.1	444		96	292	89	3,071	85	235,000
Boiler No.2	448		98	269	88	3,188	89	235,000
Boiler No.3	247		63	161	49	1,710	48	135,000
Boiler No.4	707		106	117	181	6,359	150	335,000
Boiler No.7	738		22	123	148	258	157	350,000
Total lb/hr			**384**	**962**	**555**	**14,587**	**529**	**1,290,000**

TABLE 2-5. CLEWISTON MILL POTENTIAL EMISSIONS, 3-hour case

Fuel Oil Combustion

	MMBtu/hr Ave.	Day/yr	Mgal/yr	PM	SO2	NOx	CO	VOC	Steam Lb/hr
Boiler No.1	122.3		0.82	12.2	320.0	44.8	4.08	0.23	85,078
Boiler No.2	120.0		0.80	12.0	314.0	44.0	4.00	0.22	83,478
Boiler No.3	72.8		0.49	7.3	190.5	26.7	2.43	0.14	52,421
Boiler No.4	0.0		0.00	0.0	0.0	0.0	0.00	0.00	0
Boiler No.7	0.0		0.00	0.0	0.0	0.0	0.00	0.00	0
Total lb/hr	**315.1**		**2.10**	**31.5**	**824.5**	**115.5**	**10.50**	**0.59**	**220,978**

Bagasse Combustion

	MMBtu/hr Ave.	Day/yr	Mgal/yr	PM	SO2	NOx	CO	VOC	Steam Lb/hr
Boiler No.1	313		39.2	78.4	19.6	47.0	2,821	78.4	149,922
Boiler No.2	317		39.6	79.2	19.8	47.5	2,851	79.2	151,521
Boiler No.3	167		20.9	50.0	10.4	25.0	1,501	41.7	82,579
Boiler No.4	707		88.3	106.0	117.3	192.4	6,359	150.2	335,000
Boiler No.7	738		92.3	22.1	122.5	147.6	258	156.9	350,000
Total lb/hr			**280**	**336**	**290**	**460**	**13,792**	**506**	**1,069,021**

Total Hourly Emissions:

	MMBtu/hr Ave.		PM	SO2	NOx	CO	VOC	Steam Lb/hr
Boiler No.1	436		91	340	92	2,825	79	235,000
Boiler No.2	437		91	334	92	2,855	79	235,000
Boiler No.3.	240		57	201	52	1,504	42	135,000
Boiler No.4	707		106	117	192	6,359	150	335,000
Boiler No.7	738		22	123	148	258	157	350,000
Total lb/hr			**367**	**1,114**	**575**	**13,802**	**507**	**1,289,999**

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

March 18, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Murray T. Brinson
Vice President, Sugar Processing
U.S. Sugar Corporation
P.O. Drawer 1207
Clewiston, Florida 33440

Dear Mr. Brinson:

RE: U.S. Sugar Corporation, Clewiston Mill
Boiler No. 7 - AC 26-238006 & PSD-FL-208

The Department received your letter dated February 22, 1994, in response to the Department's October 15, 1993, letter for a permit to construct Boiler No. 7 in Hendry County, Florida. Based on the review of this additional information, we have determined your application is still incomplete. The following information will be needed before the review of this application can continue:

BACT DETERMINATION

Particulate Matter (PM):

1. Please provide the technical, economic and environmental analysis data for using an electrostatic precipitator (ESP) to control particulate matter emissions.

2. The Department has made contacts with several of the ESP's manufacturers that state that ESP technology is technically feasible for this project. Please explain the basis of your conclusion.

3. Provide a copy of the final ESP test report (include the wet ESP test data) for the tests conducted with United McGill Corporation Mobile Precipitator System in January 1994.

4. Provide a comparison of the design characteristic of the test ESP and ESPs used in other high conductivity ash applications. For example, an ESP was specified in the BACT determination to control particulate emissions from a circulating fluidized bed

338 MMBtu/hr boiler firing bagassee at the Puuene Mill, Hawaiian Commercial & Sugar Company, Limited. The emission limit when firing bagasse in the boiler was specified as 0.03 lb/MMBtu.

5. What is the maximum removal efficiency an ESP vendor will guarantee for Boiler No. 7?

Nitrogen Oxides (NO_x):

6. The equipment proposed appears to be consistent with other applications which utilize Selective Non Catalytic Reduction (SNCR). However, several costs appear to be either new or higher than other applications - namely the licensing fee, start-up and testing, the model study and annual operating costs. Provide a detailed cost analysis including a copy of the vendor quote for all equipment, tasks included in the performance test and justification for the annual operating labor cost. SNCR installation was specified in the BACT determination for the Puuene Mill boiler.

Carbon Monoxide (CO):

7. The Department is taking into consideration the Boiler No. 4 stack test CO emission data. However, you need to evaluate the CO emission rates using the 0.35 lb/MMBtu standard (as in the Okeelanta Power Limited Partnership's permit).

   Your company and Okeelanta Power are proposing good combustion practices as a control technology to reduce CO and VOC emissions. As such, we fail to understand your rationale for proposing the higher emission limit for this project. Your proposed CO emissions limit is 30 times higher than the Okeelanta project burning biomass fuel.

General

8. Submit appropriate updated tables (Tables 2-3, 2-4, 2-5, and 2-6) showing the revised emission limits for the affected pollutants.

Air Quality Related Values (AQRV)

9. On February 28, 1994, the Department sent you a letter with a copy of an AQRV survey for the Everglades National Park. This survey was done by the National Park Service (NPS). In order to complete your AQRV analysis, please review the survey, contact Dee Morse of the NPS, coordinate with him any specific concerns the NPS may have with your AQRV analysis, and respond to these concerns, if any. Please provide the Department a copy of your responses.

As requested in your facsimile of March 16, 1994, the Department can schedule a meeting to discuss these issues at an early date. However, submittal of the information requested in this letter prior to the meeting will expedite review of the application.

If you have any questions regarding this matter, please write or call Teresa Heron, review engineer, at (904) 488-1344. We will resume processing this application after receipt of the requested information.

Sincerely,

John C Brown Jr.

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JCB/TH/bjb

cc: Gary Maier, SD
Claire E. Lardner, OGC
Robert Van Voorhees, Esq., Bryan Cave
Peter J. Kroll, P.E.
Jewell Harper, EPA
John Bunyak, NPS

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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 President, Sugar Processing
U.S. Sugar Corporation
P. O. Drawer 1207
Clewiston, Florida 33440

4a. Article Number
P 872 563 609

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

7. Date of Delivery
3/21/94

5. Signature (Addressee)

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

6. Signature (Agent)
Joseph [illegible]

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 563 609

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UNITED STATES POSTAL SERVICE

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Street and No. P. O. Drawer 1207	
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Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 3/17/94 AC 26-238006 & PSD-FL-208	

PS Form 3800, JUNE 1991

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 28, 1994

Mr. Peter J. Kroll, P.E.
Manager, Air Quality Engineering
ICF Kaiser Engineers, Inc.
Four Gateway Center
Pittsburgh, PA 15222-1207

Re: U. S. Sugar Corporation, Clewiston Mill
Boiler No. 7 - AC 26-238006 & PSD-FL-208

Dear Mr. Kroll:

The National Park Service (NPS) has reviewed U. S. Sugar Clewiston's PSD Class I modeling and air quality related values (AQRV) submittals. The NPS has verbally agreed with the Department that the Class I modeling analysis is complete. At the verbal request of the NPS, the Department is forwarding to you a copy of a recently completed air quality related values (AQRV) Survey for the Everglades National Park. They are requesting that you review this material and contact them directly to receive the most up-to-date information, and to discuss any specific concerns they may have with the AQRV analysis portion of U. S. Sugar Clewiston's application. Please contact Mr. Dee Morse of the National Park Service at (303) 969-2071.

Sincerely,

C. H. Fancy
Chief
Bureau of Air Regulation

CHF/cgh

Enclosure

cc: Murray Brinson, U. S. Sugar (with enclosure)
G. Preston Lewis, P.E., FDEP
Teresa Heron, FDEP

State of Florida
Department of Environmental Protection

Routing and Transmittal Slip

TO: (Name, Office, Location)

1. Preston Lewis ① Jorgen
2. ② Policy file
3.
4.

For your files!

FROM: Dave Holladay

DATE 3/3/94

PHONE

08-18-93

ICF KAISER
ENVIRONMENT & ENERGY GROUP

ICF Kaiser Engineers, Inc.
Four Gateway Center
Pittsburgh, PA 15222-1207
412/497-2000 Fax 412/497-2212

RECEIVED
FEB 23 1994
Bureau of
Air Regulation

February 22, 1994

Mr. John C. Brown, Jr., P.E.
Administrator, Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: US Sugar Corporation, Clewiston Mill
Boiler No. 7 - AC 26-238006 & PSD-FL-208

Dear Mr. Brown:

On behalf of the United States Sugar Corporation (US Sugar), we submit this second response to the Department's October 15, 1993, request for additional information relating to US Sugar's application for a construction permit for boiler No. 7 at its Clewiston Mill. Our letter to you of December 22, 1993, provided responses to the Department's requests for information Nos. 8, 9, and 10. This letter provides our responses to the remainder of the Department's requests, Nos. 1-7. These responses are being forwarded directly to Teresa Heron and Doug Outlaw for their initial review because we were told that they have the most direct responsibility for reviewing the portions of the application that relate to these questions.

In requesting additional information, the Department referred to the permit issued to Okeelanta Power on September 15, 1993, as "the most recent permit issued by the Department for this type of facility." In our meeting with your staff on December 10, 1993, we agreed that Okeelanta Power and US Sugar facilities are, in fact, different types of facilities. Therefore, the application to US Sugar's proposed Clewiston boiler No. 7 of technology adopted for Okeelanta Power would be done solely on the basis of a "technology transfer." For purposes of evaluating whether such a transfer would be appropriate, we thought it would be useful to examine some of the differences between the Okeelanta Power and US Sugar facilities.

According to its public offering memorandum, Okeelanta Power is proposing to build "a solid waste disposal, and electric and steam generating facility." (Okeelanta Power Offering Memorandum ["OPOM"] at page 3). The construction of the Okeelanta Power facility will be financed with $160 million in Solid Waste Industrial Development Revenue Bonds (OPOM at page 4).

The principal function of the Okeelanta Power facility is to generate electricity for sale to the power grid. Indeed, every aspect of the construction and operation of the Okeelanta Power facility will be financed by the sale of electricity to Florida Power & Light Company ("FP&L"). The sale of electricity to FP&L "is anticipated to provide 100% of the [Okeelanta Power] Project's operating revenues," (OPOM at page 18), including the revenues used to redeem the revenue bonds. For this reason, the Okeelanta Power facility is subject to the new source performance standards (NSPS) applicable to electric utility steam generating units, 40 CFR 60, Subpart Da, and those standards dictate the most critical emission control requirements for Okeelanta Power.

In contrast, the new boiler for which US Sugar has filed this application will be used to generate steam and power for the operation of its sugar cane grinding mill, and the financing for the project will come from the normal revenues of these operations. Therefore, the new boiler is subject to the separate requirements of 40 CFR 60, Subpart Db, because it is a different type of facility. The overall facilities are thus quite different, with US Sugar simply adding another boiler that will, in part, replace two of its existing boilers, while Okeelanta Power is constructing an entirely new grass-roots electric power generating facility.

Fuel considerations also differentiate the two facilities. Okeelanta Power will be burning wood waste in addition to bagasse and relying on coal in addition to fuel oil as a secondary fuel. Because the Okeelanta Power facility will also serve as a solid waste disposal facility, the wood waste and other biomass which is anticipated to provide one-third of the fuel for the units will be supplied "at no cost to" Okeelanta Power (OPOM at page 16). The differences in fuel varieties alters not only the economics of the two facilities, but the emissions profiles as well, with Okeelanta Power in a position to use as much as 50% non-bagasse fuels as compared with at least 90% bagasse fuel for US Sugar's new boiler. The fuel mixes and economics of the two facilities are hardly comparable.

With respect to the boilers themselves, there are significant differences in the steam conditions and probably in the combustion chambers and other critical parameters. These are difficult to quantify precisely because the final parameters for the boilers and emission control units are not yet known. As of December 15, 1993, Okeelanta Power acknowledged that "the specifications for [the electrostatic precipitator] unit have not yet been developed." (OPOM at Appendix B-25). Although Okeelanta Power notes that there are 15 boilers of the type they proposed to use currently in operation firing bagasse, it is a fact that not one of these boilers presently uses an electrostatic precipitator.

Okeelanta Power relies solely on a presumption of effectiveness as the basis for selecting its particulate matter control technology -- it presumes feasibility because ESPs have been used to control emissions from other forms of biomass fuel (OPOM at B-25). Having a construction schedule that runs through early 1996 and a phase-in period that extends until January 1, 1999, (OPOM at pages 4, 16), Okeelanta Power can more readily afford to rely on such presumptions, and the applicable NSPS requirements that dictate its emission control requirements leave Okeelanta Power no real alternative.

Recent testing conducted by US Sugar, however, shows that this presumption of effectiveness for the ESP cannot be simply transferred and relied upon for a boiler like the proposed Clewiston boiler No. 7. Thus, the NSPS requirements that serve as compulsory strictures for the Okeelanta electric power generating facility should not dictate the control requirements for US Sugar's new industrial boiler.

Finally, it must be noted that the Department's determinations on the Okeelanta Power permit were issued on September 27, 1993, and were not final and available to US Sugar at the time the application for Clewiston boiler No. 7 was filed on September 17, 1993. Where a new application of technology is only prospective and scheduled to be implemented and tested only after a different type of unit subject to different NSPS requirements is completed, the prospective yet unproven technology should not dictate BACT requirements.

The key differences between the Okeelanta Power and US Sugar facilities are summarized in Table 1. Thereafter we present the remaining responses to the Department's requests for further information. For convenience in reviewing the subsequent responses, the Department's requests for information are presented in *italics*, and US Sugar's responses are presented in normal typeface.

ICF KAISER

TABLE 1
Comparison of Okeelanta Power and US Sugar Combustors

	Okeelanta Power	US Sugar Boiler No. 7
Will be an "electrical utility steam generating unit" under 40 CFR 60.41a	Yes	No
Applicable New Source Performance Standard (NSPS)	40 CFR 60, Subpart Da: Electric Utility Steam Generating Units	40 CFR 60, Subpart Db: Industrial-Commercial-Institutional Steam Generating Units
NSPS particulate emission limit, lb/MM Btu	0.03[1]	0.1 (for fuel oil combustion)
NSPS NO_x removal efficiency requirement	30% for oil combustion 65% for coal combustion	No requirement for NO_x removal
Fuels	Primary: 451,000 ton/yr wood chips and 901,960 ton/yr bagasse[2] Secondary: coal, fuel oil	Primary: 485,905 ton/yr bagasse Secondary: fuel oil
Maximum total heat release, MM Btu/hr	2,145 for three boilers	738 for the one boiler
Maximum secondary fuel heat release, MM Btu/hr	1,470 for three boilers	255 for the one boiler

1 Note that 40 CFR 60, Subpart Da requires the minimum particulate emission standard to be 0.03 lb/MM Btu, which is what Okeelanta Power proposed and FDEP has approved.

2 These are estimated values; there is no permit limit to the amount of wood chips which can be fed.

Table 1
Comparison of Okeelanta Power and US Sugar Combustors (cont.)

	Okeelanta Power	US Sugar Boiler No. 7
Maximum annual percentage of heat release from secondary fuel	25 percent	10 percent
Steam conditions	1500 psig, 950°F	600 psig, 750°F

ICF KAISER

1. *Is this facility generating any electricity? If so, how much (MW)? Is any part of this electricity being sold to the power grid? Please explain.*

The US Sugar Clewiston mill has the capacity to generate electricity, which is used almost exclusively for powering the mill equipment. In 1993, the mill generated approximately 56.4 MM KWH of electricity and was able to sell electricity to the power grid on those occasions when the mill generated more power than was being consumed by the mill. During other periods of operation, however, the mill was unable to meet all of its power needs and found it necessary to purchase electricity from FP&L. In 1993, the mill was a net consumer of electricity and purchased approximately 6.2 MM KWH.

Clewiston boiler No. 7 is not being constructed for the purpose of selling electricity to the power grid. Thus, neither the mill nor Boiler No. 7 will be operated as a cogeneration unit as defined in 40 CFR Part 60, Subpart Da.

2. *Expand the BACT analysis to include the use of other air pollution control systems for this type of facility. The most recent permit issued by the Department for this type of facility has set a particulate matter (PM/PM10) limit of 0.03 lb/MM Btu when burning biomass (bagasse & wood chips), using an electrostatic precipitator as the control technology. In addition the nitrogen oxides (NO_x) emission level has been set at 0.06 lb/MM Btu with the use of selective non-catalytic reduction (SNCR) technology. BACT for the sulfur dioxide (SO_2) standard has been set at 0.10 lb/MM Btu (24 hr-average) and at 0.02 lb/MM Btu (annual average) with the burning of No. 2 fuel oil with a maximum of 0.05% sulfur content. The carbon monoxide (CO) standard has been set at 0.35 lb/MM Btu (8-hr average). Volatile Organic Compounds (VOC) emissions have been set at 0.06 lb/MM Btu). See attached copy.*

FDEP has asked for the US Sugar BACT analysis to be expanded to include consideration of the following aspects of the Okeelanta Power permit to construct:

- An electrostatic precipitator (ESP) for PM10 control, and an emission limit of 0.03 lb/MM Btu

- Selective noncatalytic reduction (SNCR) for NO_x control, and an emission limit of 0.06 lb/MM Btu

- An SO_2 emission limit of 0.10 lb/MM Btu (24-hr average), based on burning No. 2 fuel oil with 0.05% sulfur

- A CO emission limit of 0.35 lb/MM Btu (8-hr average)

- A VOC emission limit of 0.06/lb MM Btu

Particulate Matter. US Sugar did, in fact, consider an ESP for particulate matter control in the BACT analysis presented in the application, as shown in Section 5.2.1.4, on page 5-9 (see Attachment 1). An ESP has not yet been commercially applied to any bagasse combustor, and therefore an ESP was deemed to be technically infeasible.

Furthermore, the Okeelanta Power application did not include any demonstration of commercial availability or feasibility of an ESP for a bagasse combustor. Nor did the application prompt the need for a BACT determination on an ESP by the Department, because Okeelanta Power netted out the particulate matter emissions from the cogeneration facility. The Okeelanta Power simply proposed to comply with the applicable new source performance standard (NSPS) that must be met by any facility of its type. Accordingly, there has been no BACT "determination" that would dictate the outcome of the Department's determination for US Sugar on this application.

As we have stated before and demonstrated above, there are profound differences between the Okeelanta Power facility and US Sugar's proposed industrial boiler. The most obvious technological difference is that Okeelanta Power's boiler is subject to an entirely different NSPS -- one that precluded reliance on the only established particulate control technology for bagasse combustors. All previous BACT determinations for bagasse boilers have identified wet scrubbers as the control technology of choice.

Because the NSPS of 40 CFR 60, Subpart Da, applied to the Okeelanta Power facility, the minimum particulate emission standard was 0.03 lb/MM Btu. Wet scrubbers are the only control devices currently in operation on bagasse/oil-fired steam boilers anywhere in the sugar industry. Although these units are capable of meeting particulate emission limits of 0.10 lb/MM Btu for fuel oil combustion and 0.15 lb/MM Btu for bagasse, they have not been able to attain an emission level as low as 0.03 lb/MM Btu. This more stringent particulate emission standard compelled Okeelanta Power to consider unproven technologies for the sugar industry, such as an ESP.

At the present, there are unanswered questions about the potential of an ESP such as proposed by Okeelanta Power to achieve the control level that they predict. One of the key design parameters for an ESP is flyash resistivity. Okeelanta Power may be able to overcome problems associated with high flyash resistivity, because they will combust a significant amount of wood chips and coal in addition to bagasse, and thus the flyash resistivity will be considerably different from exclusively bagasse combustion. US Sugar, in contrast, will only combust bagasse with a very small amount (less than 10% on an annual basis) of fuel oil. Based on the above reasons, US Sugar concluded that an ESP would be technically infeasible for the new bagasse combustor.

Testing conducted by US Sugar with a dry ESP has confirmed the validity of these concerns (Attachment 2). The dry ESP was unable to achieve, or even approach, the requisite removal efficiency with bagasse flyash. Thus, the particulate matter control technology proposed by Okeelanta Power would be technologically infeasible for US Sugar boiler No. 7. Additional testing with a wet ESP suggested that different results might be achieved with that type of process, but raises additional concerns about how to judge the capability of a control technology not yet proven in practice on bagasse boilers. At the very least, this testing confirms that the technology approved for the Okeelanta Power facility cannot simply be "transferred" and presumed applicable to Clewiston boiler No. 7, especially where the Okeelanta Power ESP control unit has not even been designed, tested, or operated. Thus, the Okeelanta Power permit should not be used as the basis for a BACT determination for particulate matter control on this permit application.

The conclusion that wet scrubbers constitute BACT for bagasse boilers is supported by all previous FDEP BACT determinations for these boilers. This was further confirmed in discussions that ICF Kaiser had with the Department on May 26, 1993 seeking guidance relative to boiler No. 7. At that time, we were advised that BACT for a bagasse combustor was a wet scrubber, and this reinforced the findings of our top-down BACT analysis.

This conclusion is further supported by the facts and circumstances surrounding the Okeelanta Power permit application. Okeelanta Power was compelled by the applicable NSPS to seek a control technology for PM without consideration of technical or economic feasibility. Indeed, no BACT determination for PM control was either required or made by FDEP, because the replacement of Okeelanta Power's existing boilers with the new cogeneration units was projected to result in a net reduction in PM emissions. Thus, FDEP has not yet been called upon to assess the technical feasibility of using an ESP to achieve any specific control level for PM emissions from a bagasse boiler.

The proposal by Okeelanta Power to implement this technology on an unconstructed mixed-biomass-fuel boiler that will not be constructed and placed in operation until 1996 is not an adequate basis for requiring the adoption of an untested technology for a bagasse boiler using only oil as its supplemental fuel. This would be appropriate only, if at all, after successful operation and some basis for concluding that ESPs will work as effectively on bagasse as on mixed biomass fuels and coal. Absent such supporting data, there is no reason to presume that an ESP is feasible for this type of boiler or that an ESP, even if technically feasible, would be able to achieve the same degree of control on the fuels that US Sugar plans to burn.

Nitrogen oxides. Palm Beach County, which is where the Okeelanta Power facility will be located, is currently a nonattainment area for ozone. Hendry County, which is where the US Sugar boiler No. 7 will be located, is an attainment area for both NO_x and ozone. Because NO_x is a precursor to ozone, NO_x emissions are thus a greater concern in Palm Beach County than they are in Hendry County, where boiler No. 7 will be located.

SNCR was considered explicitly in the BACT analysis in Section 5.3.1.2, on pages 5-23 through 5-30 (see Attachment 3). There are a number of significant factors that weigh against the use of SNCR for US Sugar boiler No. 7:

- It will result in emission of a toxic chemical (ammonia) from the stack.

- It will require storage, handling, and use of a hazardous chemical (anhydrous ammonia) onsite at a facility where it is not currently used unless aqueous ammonia is used. This latter option, however, has not been used by Exxon, and they are therefore unwilling to guarantee the performance of aqueous ammonia for SNCR.

- Subpart Da requires utility steam generating units combusting oil or coal to achieve a reduction of potential NO_x emissions of 30% or 65%, respectively. Thus Okeelanta Power was compelled by the NSPS to use NO_x control technology, but subpart Da does not impose this same requirement for US Sugar boiler No. 7. This serves again to highlight the significant differences between the two projects.

- It would add about $910,000/year to the cost of the project, and the average cost-effectiveness is over $4,000/ton. This exceeds the upper limit for cost-effectiveness that FDEP and EPA have considered as reasonable for controlling NO_x emissions.

- US Sugar would be willing to reduce the NO_x emission limits for low-sulfur diesel oil to 0.2 lb/MM Btu, which is almost equivalent to what Okeelanta Power proposed for oil and coal. The nitrogen content of low-sulfur diesel will be about 0.015%, but the nitrogen content of low-sulfur residual oil (originally proposed as BACT by US Sugar) was more than 0.4%. Therefore, by switching boiler No. 7 to low-sulfur diesel oil, the fuel-bound NO_x emissions should decrease by more than 96%. In general, fuel-bound NO_x accounts for about half of the NO_x emissions; therefore reducing fuel-bound NO_x emissions by more than 96% will reduce total NO_x emissions from fuel oil by more than 48%.

Sulfur dioxide. Note that the potential SO_2 emissions for Okeelanta Power are 1,154 tons/yr, but for boiler No. 7 are only 435 tons/yr. US Sugar has also proposed a permit limitation on fuel oil usage such that there will be **no net increase in hourly SO_2 emissions** from fuel oil combustion as a result of this project. In fact, because the average sulfur content of the fuel oil burned at the Clewiston mill will decline, the hourly SO_2 emissions will decrease.

US Sugar now proposes the use of 0.05% sulfur diesel oil (defined as "very low sulfur fuel oil" and "distillate oil" under 40 CFR 60, Subpart Db) and a maximum annual capacity factor for fuel oil of 10% as BACT, although this grade of oil will cost currently in excess of $9.35/barrel more than the 2.5% sulfur residual oil which is currently used at the Clewiston mill, and $1.35/barrel more than the 0.5% sulfur residual oil which was originally proposed by US Sugar as BACT. Thus, the increased cost for this control step alone be more than one half million dollars.

Carbon monoxide. As presented in Attachment E of the application for boiler No. 7 (and offered here as Attachment 4), US Sugar has requested a higher CO emission limit, because stack testing of their existing boilers indicates that a CO emission limit of 0.35 lb/MM Btu is not feasible. CO emissions will be controlled by good combustion practices as discussed in Section 5.4, pages 5-31 through 5-33 (see Attachment 5).

The requested CO emission level during the crop season is based on testing initiated by US Sugar at the request of the Department for the purpose of adjusting CO emission factors used for permitting other US Sugar boilers. Following the initiation of CO testing with EPA

Method 10 pursuant to permits issued for US Sugar Clewiston boiler No. 4 and other boilers in the Florida sugar industry, the Department and the industry soon realized that the previously assumed CO emission factor of 0.25 lbs/MM Btu was invalid. Accordingly, on October 26, 1989, Philip R. Edwards, Deputy Assistant Secretary of the Department of Environmental Regulation ("the Department") requested US Sugar to test emissions from boiler No. 4 using EPA Method 10 during the 1989-90 crop season (see Attachment 6) to "help the Department determine a reasonable CO emission factor for boilers of this type." The requested testing was performed and reported to the Department on October 8, 1990. US Sugar's proposed CO emission level of 9.0 lbs/MM Btu, as requested in this application and in the pending application for renewal of the operating permit for Clewiston boiler No. 4, is derived from a statistical analysis of the results of this 1989-90 crop season testing and additional testing performed during subsequent crop seasons. The data used to derive the proposed CO emission level are included in Attachment E to the original application (see Attachment 7).

The CO emission levels achievable by US Sugar in boiler No. 7 are not likely to be comparable to those proposed by Okeelanta Power. The average moisture content of bagasse is more than 50%, but wood waste and coal have much lower moisture contents. Okeelanta Power will burn a significant amount of wood chips and coal in addition to bagasse, and thus the average fuel moisture content will be notably lower than that of the US Sugar boiler No. 7. Fuel which is very moist is harder to combust, and thus CO higher emissions would be expected from US Sugar boiler No. 7 than from Okeelanta Power.

<u>Volatile organic compounds</u>. As mentioned earlier, Okeelanta Power will be in an ozone nonattainment area, but boiler No. 7 will not be, and thus VOC emissions are a greater issue for that facility. Similar to Okeelanta Power, VOC emissions for boiler No. 7 will be controlled by good combustion practices as discussed in Section 5.4, pages 5-31 through 5-33 (see Attachment 8). As noted above, the moisture of solid fuels for Okeelanta Power is considerably lower, and thus lower VOC emissions would be expected than from US Sugar boiler No. 7.

3. *Estimate the potential emissions (with controls) for Boiler No. 7 for all pollutants, criteria and non-criteria.*

We understand that this question relates to re-estimating the potential emissions for boiler No. 7 after finalization of the BACT analysis. The potential emissions for boiler No. 7 as originally proposed are presented in Tables 2-3, 2-4, 2-5 and 2-6 (see Attachment 9). These tables will be revised and resubmitted once final emissions levels are established.

4. *List the net emission increases or decreased (net contemporaneous change analysis) for each pollutant. This table should include emissions calculated using at least the last two years of actual emissions for each boiler (that is going to be shut down) and the potential emissions (with controls) of the proposed boiler No. 7. If changes in the net increases or decreases of these pollutants lead to additional remodeling requirements, please perform the required modeling.*

We understand that this question relates to re-estimating the net emission increase/decrease for each pollutant for boiler No. 7 after finalization of the BACT analysis. We have recalculated the baseline emissions as defined in Table 3-3 per your request, using two years of actual emissions for boilers No. 5 and 6 (see Attachment 10). The net change in total emissions as a result of this recalculation is very low. This table will be revised and resubmitted once final emission levels are established.

5. *Page 8-5 of the application (proposed permit conditions) lists the use of residual oil with a sulfur content of 2.5%. Several applications currently being processed by the Bureau are proposing 0.05% sulfur in No. 2 fuel oil. What is the lowest percent sulfur in No. 2 and No. 6 fuel oil available in your area and what is the cost/MM Btu for each?*

The lowest-percent-sulfur diesel (No. 2) and residual (No. 6) fuel oil offered for sale in our area and the relative costs are as shown below:

	Lowest % S	$/Bbl	$/MM Btu	tpy SO2	$/yr Fuel Cost
Diesel oil	0.05	27.44	4.68	12.7	$2.11 million
Residual oil	0.5	26.09	4.14	127.0	$1.86 million

Assuming yearly fuel oil usage of 3 million gallons, the above table represents the ton/yr SO_2 emitted and the yearly fuel cost for these two options. Therefore, the incremental cost-effectiveness of using 0.05% diesel oil versus 0.5% residual oil is $2,121/ton. The Clewiston mill currently uses 1.5% sulfur residual oil ($3.03/MM Btu) in boiler No. 4 and 2.5% sulfur residual oil ($2.82/MM Btu) in all other boilers.

6. *Estimate the PM/PM10 emissions from the fugitive dust sources as a result of this project. There is little information on specific equipment, drawing showing equipment layout, or fugitive dust controls for the amount of bagasse that will be handled at this plant. Please provide drawings of all storage and material handling equipment with notations of how fugitive PM/PM10 emissions from hauling the materials to the plant and the disposing of any waste be controlled.*

US Sugar anticipates that this project will **reduce fugitive particulate emissions** because all of the bagasse produced by the mill will be burned almost immediately. The Clewiston mill currently produces more bagasse than it can burn in all of its existing boilers. The surplus is sent to a reclaim pile or shipped off-site, and both of these operations have the potential to create fugitive particulate. US Sugar expects that the new boiler No. 7 will virtually eliminate these two sources of fugitives by allowing US Sugar to burn all of the bagasse that is produced. Thus, the bagasse will not be placed into storage and handled again for shipment.

As noted in Section 2.4.3 on page 2-20, the principal sources of fugitive particulate emissions will be the same for the proposed project as the current Clewiston mill operates. US Sugar has provided a great deal of information on our bagasse storage and handling equipment to FDEP in the past, and has installed control equipment and implemented procedures to reduce fugitive emissions from that equipment. We have provided a copy of the drawings and description for those systems as Attachment 11 for your reference. Please note, however, that none of these systems will change as a result of this project.

7. *How will the heat input by the various fuels be monitored? What parameters of the fuels will be monitored and at what frequency? What test methods will be used? Where will the samples be collected on each fuel used at the proposed facilities?*

How will this data be used to show compliance with the various SO_2 standards?

Heat input. As described in Section 2.1 on page 2-6, heat input to the boiler from fuels is calculated as follows:

Steam temperature and pressure, boiler feedwater temperature and pressure, and steam flow rate are measured. Bagasse consumption is determined through the following procedure:

a. The enthalpy of the steam and the boiler feedwater are determined from the temperature and pressure measurements.

b. Total heat input to the steam is calculated from the enthalpy difference and the steam flow.

c. Heat input to the boiler due to oil firing is calculated from the fuel oil flowmeter readings and the fuel oil heating value provided by the oil supplier. An 80% boiler efficiency is assumed when firing fuel oil and is used to determine the heat input to the steam.

d. The remaining required heat input to the steam due to bagasse firing is then calculated as the difference between total heat input to the steam (Item (b) above) and the heat input due to oil firing (Item (c) above).

e. Heat input to the boiler from bagasse firing is then determined based on 55% efficiency, and the amount of bagasse required is calculated based upon an average of 8,000 British thermal units per pound (Btu/lb) or bagasse (dry basis).

Parametric monitoring and frequency. Parameters to be monitored for the fuels are, as mentioned above, the fuel oil flowrate (continuous monitor) and fuel oil analysis (each tanker truck shipment). Per the NSPS [40 CFR 60.49(b)(r)], obtaining and maintaining fuel receipts from the fuel supplier which certify that the oil meets the

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definition of distillate oil as defined in 60.41b will ensure compliance with the SO_2 emission standard.

Whereas the boiler No. 7 PSD permit application proposed the use of 0.5% sulfur residual oil in the existing common fuel oil tank, US Sugar now proposes to install a dedicated tank, pumps, and piping for very-low-sulfur (0.05%) diesel oil, at an additional expense of about $300,000.

Test methods and sample collection. US Sugar will not sample and analyze its fuel oil, but will instead utilize the analysis of each tanker truck load provided by the fuel oil vendor.

We believe that the information provided in this response will satisfy your needs for additional information on all of the remaining items. Please contact me at (412) 497-2024 or Bob Van Voorhees at (202) 508-6014 if you have any questions about the information provided in these responses. We look forward to working with you and your staff to assist in your review and approval of this permit application.

Very truly yours,

Peter J. Kroll

Peter J. Kroll, P.E.
Manager, Air Quality Engineering

cc: G. Preston Lewis, P.E., FDEP
Douglas G. Outlaw, P.E., FDEP
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Murray Brinson, US Sugar
Peter Barquin, US Sugar
Peter Briggs, US Sugar
Robert Van Voorhees, Esq., Bryan Cave
D. Knowles, S Dist.
J. Harper, EPA
J. Bunyak, NPS

ATTACHMENT 1

Excerpt from PM BACT Analysis

5.2.1.4 Electrostatic Precipitators

Electrostatic precipitators (ESP) particulate collection is accomplished by first imparting an electrical charge to the particles, allowing the charged particles to migrate to a collecting electrode, and dislodging the collected particles from the collecting electrodes. Particle charging is normally accomplished with a high-voltage DC corona. Particle removal is performed by rapping or vibrating the collecting electrodes.

ESPs have the inherent disadvantage of removing only particulate matter. Another control device would be needed to remove gaseous pollutants such as SO_2. This is typically addressed by the use of dry sorbent injection, as discussed previously. Disposal of a dry solid waste product would also be required.

ESPs are in operation on many wood, solid-waste and coal-fired boilers. They have not, however, been applied to bagasse-fired boilers. Precipitator vendors contacted recently and a study conducted several years ago indicate that electrostatic precipitation of bagasse ash would probably not be feasible. The vendors also caution against possible fire hazard and explosion potential. Information does not currently exist on the resistivity of bagasse fly ash, and, therefore, the design of an ESP for this fly ash cannot be easily defined. Because of the uncertainty associated with application of ESPs to bagasse boilers, this technology is considered to be unproven and thus was not considered further in the BACT analysis.

5.2.1.5 Low-sulfur Fuel Oil

The sulfur content of residual oil typically ranges from 0.3-3.0% by weight. Because the level of SO_2 emissions is directly related to the amount of sulfur in the fuel, a low-sulfur-containing fuel can be used to meet the SO_2 emission limitation specified by the NSPS regulations.

Under the current NSPS regulations for industrial steam generators (40 CFR 60, Subpart Db), an SO_2 emission rate of 0.5 lb/MM Btu must be met by the proposed boiler No. 7. The sulfur content of the residual oil used in boilers No. 1, 2 and 3 is 2.5% which is equivalent to an uncontrolled SO_2 emission factor of approximately 2.7 lb/MM Btu. U.S. Sugar Corporation is proposing to use "very-low-sulfur" fuel oil (no more than 0.5% sulfur) to meet the NSPS limit, as 40 CFR 60.42b specifically allows. This is equivalent to an uncontrolled SO_2 emission factor of approximately 0.5 lb/MM Btu.

The intent of U.S. Sugar Corporation has and always will be to minimize the burning of fuel oil in the existing boilers as well as the proposed boiler No. 7. For example, during 1992 fuel oil provided less than 1% of the Clewiston mill's total heat input requirements. Oil is normally required for starting up the boilers at the beginning of the crop-year (generally requires less than 24 hours). After startup, oil will only be fired when the supply of bagasse to the boiler is interrupted.

ATTACHMENT 2

ESP Test Report

Preliminary Report

To

United States Sugar Corporation
Clewiston, Florida

Phase I Mobile Electrostatic Precipitator Test Program

Prepared By:

United McGill Corporation

Columbus, Ohio

January 28th 1994

The following is a preliminary report addressing the phase I operation and testing of United McGill Corporation's (UMC) mobile precipitator system at U.S. Sugar's Clewiston Florida Sugar Mill.

Introduction:

During the weeks of January 2nd and 9th 1994 a four field dry mobile electrostatic precipitator was operated, in a dry configuration, at U.S. Sugar's Clewiston Sugar Mill. The unit treated between 3200 and 4700 acfm extracted from the 300,000 pound/hr #4 bagasse fired power boiler exhaust. The purpose of this test was to determine the performance and feasibility to control this bagasse boiler with a dry electrostatic precipitator.

Test Configuration:

A total of five sets of inlet and outlet tests were run. These tests were approximately one hour in duration and conducted in accordance with the EPA method 5 procedure. The treated flow was varied form 2851 acfm to 4750 acfm while the number of operating fields were also varied in accordance with the following matrix:

Test #	# of Active Fields	Inlet ACFM	Events During Test
1	3	2993	Fields 1 & 2 Rapped
2	1	2851	None
3	4	4750	None
4	4	4607	Field 2 Rapped, Soot Blown
5	4	4540	Fields 1 & 2 Rapped

The number of active fields was varied to determine the effect of collection area and multiple fields on performance. The inlet volume flow was varied to determine the impact of linear velocity upon performance and to evaluate the relationship between volume flow and collection area.

Results:

Preliminary test results were generated within 24 hours of the tests. The final test results were not yet available as of the writing of this preliminary report.

U.S. SUGAR: PHASE I PRELIMINARY TEST RESULTS: DRY OPERATION				
Test #	# of Fields	Velocity (FPS)	Inlet Concentration (gr/dscf)	Outlet Concentration (gr/dscf)
1	3	2.0	0.83	0.059
2	1	1.9	0.823	0.068
3	4	3.2	0.955	0.071
4	4	3.1	1.14	0.20
5	4	3.0	1.01	0.24

In addition to method 5 testing, visual opacity observations were conducted. These observations showed opacity excursions during rapping and other system events.

Conclusions:

The best preliminary outlet concentration achieved during the testing was 0.05 gr/dscf. The target emission goal of 0.03 pounds per million BTU of boiler fuel input equates to approximately 0.01 gr/dscf.

The lower than expected performance observed during the dry electrostatic precipitator testing is similar to UMC's past experiences with some coal and organic fired boilers in which the ash contained high carbon content, typically greater than 25%. This high carbon content typically results in low resistivity. " Low dust resistivity refers to the inability of particles to retain a charge once they have been collected on the plate." [1]

Particle reentrainment is a substantial problem at low resistivity, and dry ESP performance is very sensitive to factors affecting reentrainment, including rapping and flow distribution.

> The low resistivity problem typically results from the chemical characteristics of the particulate and not from temperature. The particle may be enriched with compounds that are inherently low in resistivity, either because of poor operation of the process or the inherent nature of the process.
>
> Examples of such enrichment include excessive carbon levels in fly ash (due to incomplete combustion), the presence of naturally occurring alkalies in wood ash, iron oxide in steel making operations, or the presence of other low-resistivity materials in

---

[1] California Air Resources Board, Compliance Division, "Electrostatic Precipitators", June 1990

the dust.[2]

United McGill has observed this low resistivity problem on other organic material combustion processes including wood fired boilers. Wood fired boilers with ash containing low (<20-25%) carbon show good precipitator performance, while precipitators controlling ash with high carbon content exhibit poor performance.

In the case of the bagasse fired boiler tested at the U.S. Sugar Clewiston Sugar Mill, the poor performance of the dry mobile precipitator indicates that a extremely large precipitator with very low face velocity would be required to achieve the 0.03 LB/MMBTU outlet level desired, if the ash characteristics remain unchanged. In our opinion the full scale dry electrostatic precipitator would not be economically feasible and would be suspectable to performance degradation during process changes and upset conditions. Since the potential for precipitator fires also increases with high ash carbon levels, the long term performance of the unit might also suffer from damaging plate fires.

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2 California Air Resources Board, Compliance Division, "Electrostatic Precipitators", June 1990

ATTACHMENT 3

Excerpt from NO_x BACT Analysis

The nitrogen content of residual oil typically ranges from 0.2-0.6% by weight. Because the level of fuel-bound NO_x emissions is directly related to the amount of nitrogen in the fuel, a low-nitrogen-containing fuel can be used to meet the NO_x emission limitation specified by the NSPS regulations for industrial boilers.

Under the current NSPS regulations for industrial steam generators (40 CFR 60, Subpart Db), a facility firing less than 250 MM Btu/hr which combusts distillate oil or residual oil with a nitrogen content of 0.3% or less, and having a federally enforceable annual capacity factor of 10% or less for oil is not subject to quantitative NO_x emission limits.

5.3.1.2 Post-combustion Controls

Selective Non-Catalytic Reduction

SNCR describes post-combustion control technologies that remove NO_x by the addition of a reactant such as urea or ammonia into the fluegas and subsequent reduction of NO_x. Two available technologies are thermal $DeNO_x$ and the NO_xOUT process.

Thermal $DeNO_x$--Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high-temperature SNCR of NO_x, using ammonia as the reducing agent. Thermal $DENO_x$ requires the fluegas temperature to be a relatively narrow range (1800°F +/- 100°F). The limiting phenomenon is the injection of ammonia in the optimum boiler locations so as to achieve maximum ammonia/NO_x mixing within the desired temperature window, consistent with normal boiler operation. This requires boiler temperature profile mapping as a function of load.

Ammonia is a toxic chemical which has the potential to be accidentally released. The handling of this chemical would require stringent safety precautions and procedures, as well as additional facilities.

NO_xOUT Process--The NO_xOUT process originated from research by the Electric Power Research Institute (EPRI) on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc. for commercialization. In the NO_xOUT process, aqueous urea is injected into the fluegas stream ideally within a temperature range of 1600°F to 1900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/_2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. The potential advantages of the system over Thermal $DeNO_x$ is lower capital and operating costs of urea injection, and use of a nontoxic and nonhazardous reactant.

Potential disadvantages of the system are formation of ammonia from excess urea treatment and sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold-end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases, with removal efficiencies of 60-65%. For either SNCR process, the gas residence time is important. The suggested residence time for SNCR is about 0.5 to 1 second.

There are no proven applications of SNCR technology for bagasse combustion, but the Thermal $DeNO_x$ process has been applied to industrial boilers. Thus SNCR is deemed technically feasible for bagasse combustors.

Selective Catalytic Reduction

The SCR process uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600-750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR equipment in an oil-fired boiler would have to be placed between the economizer and air preheater to achieve proper temperature conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

Although the operating experience on oil-fired boilers is limited, certain cost, technical, and environmental considerations have surfaced. Most of these considerations were discussed in the preceding section under SNCR, which has similar considerations. Ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the air preheater and flue surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter; although the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from carbonaceous fuels also could form ammonium salts.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°-950°F, have been available commercially only recently. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800-900°F. At temperatures of 1000°F and above, the zeolite catalyst will be irreparably damaged. The fibrous and moisture-laden nature of particulate matter generated by bagasse boilers would likely cause blockage in the catalyst. Even with large pore openings, particulate would likely adhere to catalyst sites and render the catalyst ineffective. In addition, it may not be possible to achieve the desired fluegas temperature without reheating because exhaust temperatures of bagasse boilers are relatively low (500-600°F).

There are no applications of SCR on bagasse boilers. Based on this and the complex problems associated with applying a catalyst bed to this type of combustor, the applicability of this technology is unknown. Therefore SCR is judged infeasible for this application.

5.3.2 Evaluation of Technically Feasible NO_x Control Methods

5.3.2.1 Ranking of Feasible Control Technologies

A baseline emission level must be established as the basis for top-down BACT ranking and for economic analysis purposes. The baseline is defined as the uncontrolled emission rate of the process being reviewed. For the impact analysis, the uncontrolled NO_x emission rate was estimated to be 1.2 lb/ton or 0.167 lb/MM Btu based on bagasse combustion. This is the AP-42 emission factor for bagasse boilers, and appears to be a reasonable average emission rate based on industry test data.

As discussed previously, SNCR can potentially achieve an NO_x removal efficiency of up to 70%, but 55% was assumed as a more conservative approach for this unproven application. FGR can potentially achieve an NO_x removal efficiency of up to 40%, but 30% was assumed as a more conservative approach for this unproven application. LNB can achieve an NO_x removal efficiency of 30-60% (for fuel oil combustion only), but 45% was used as a conservative estimate for this analysis. Low-nitrogen fuel oil can achieve 25-50% reduction in fuel-bound NO_x (for fuel oil combustion only), but 35% was used as a conservative estimate. OFA can achieve an NO_x removal efficiency of 10-30% but 0% was used for this analysis, as it is an inherent part of the combustor design, and thus is part of the baseline emission.

Therefore, the BACT top-down hierarchy ranks SNCR first, FGR second, LNB third and low-nitrogen fuel oil fourth.

5.3.2.2 Analysis of Control Technology Impacts

Technical Issues

Of the combustion modification techniques, only OFA is currently used for bagasse and is integral to the design of bagasse-fired boilers. This technology is one of the likely reasons for the relatively low NO_x emissions exhibited from these boilers. Additional overfire air would not likely reduce NO_x emissions significantly from current levels. LNB technology is not currently used nor is this technology applicable to bagasse combustion due to the nature of the fuel and existing burning methods. LNB can be applied to fuel oil combustion, however. FGR, while potentially applicable to bagasse-fired boilers, has not been applied and its effectiveness for NO_x reduction is questionable.

SNCR and SCR, the post-combustion control technologies, have not been applied to bagasse-fired boilers. The application of SNCR, although possible, would be extremely difficult to implement, because the required temperature zones for reaction will spatially vary within a bagasse boiler as a function of boiler load. This variability, coupled with the relatively small boiler space make the overall technical feasibility of SNCR questionable. Other technical issues related to SNCR include:

- Ammonia distribution: NH_3 must be uniformly distributed in the exhaust stream to ensure optimum mixing with NO_x in the narrow temperature window.

- Temperature profile: the narrow temperature range that SNCR systems operate within (i.e., about 100°F) must be maintained even during load changes.

- Ammonia control: a molar ratio of at least 1:1 NH_3 to NO_x generally is needed to ensure high removal efficiencies. The quantity of NH_3 introduced must be carefully controlled: with too little NH_3, the desired control efficiency is not reached; with too much NH_3, emissions of NH_3 (referred to as "slip") can occur.

- Gas residence time: residence time of the combustion gas after ammonia injection must be within a narrow range to ensure satisfactory removal efficiency.

- Special storage and handling equipment are required for ammonia.

Environmental Effects

SNCR has several environmental effects which should be considered:

- Ammonia slip: NH_3 slip (NH_3 that passes unreacted into the atmosphere) can occur if:

  - Too much ammonia is added
  - NH_3 distribution is not uniform
  - The velocity is not within the optimum range
  - The proper temperature is not maintained

- Ammonium salts: ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can form when firing oil or bagasse, and are emitted as particulates.

- Ammonia transportation and storage: storage and handling of anhydrous ammonia poses additional environmental risks. Appropriate contingency plans and controls in the event of a release required.

There are no significant environmental issues associated with FGR, LNB, or low-nitrogen fuel oil.

Energy Requirements

Additional energy will be required to operate ammonia pumps and dilution air fans (100 kw) for SNCR. There will also be additional energy requirements associated with the large FGR fan (428 kw).

Economic Analysis

An economic analysis of SNCR and is presented in Table 5-6. This table shows that the TCI of SNCR applied to this bagasse boiler would be at least $1.6 MM, and the AC would be $910,000/yr. The economic analysis also shows that the TCI of FGR applied to this bagasse boiler would be at least $942,300 and the AC of FGR would be at least $897,500/yr. The analysis also establishes that the TCI of LNB applied to this bagasse boiler would be at least $95,400 and the AC would be $20,300/yr. The TCI for low-nitrogen fuel oil is $55,000 and the AC is $450,000/yr.

5.3.3 BACT Analysis Summary for NO_x

The top-down BACT analysis for NO_x for the proposed boiler firing bagasse and residual oil as the auxiliary fuel is summarized in Table 5-7.

The ACE values are $4,006, $7,244, $246, and $7,264 per ton of NO_x removed for the SNCR, FGR, LNB and low-nitrogen oil, respectively. The ICE values are $121, $21,240 $-20,809 and $7,264 per ton of NO_x removed for the SNCR, FGR, LNB and low-nitrogen oil, respectively. The ICE values for many of these alternatives are higher than the levels that FDEP and EPA have considered as reasonable for controlling NO_x emissions. Therefore, the use of SNCR and FGR are considered economically infeasible for SO_2 removal.

The economics of low-nitrogen fuel oil look much worse than that of LNB, but this is based on the assumed use of 2.5% sulfur fuel oil with its relatively high nitrogen content (0.3-0.5%). As discussed in the previous section, very-low-sulfur fuel oil has been proposed as BACT for SO_2. Per discussions

Table 5–6 Cost Analysis for NOx Emissions Control

Cost Items	Cost Factors	SNCR	FGR	LNB	Low–N Oil
DIRECT CAPITAL COSTS (DCC)					
(1) Purchased Equipment Cost:					
(a) Basic Equipment/Services	Vendor Quotation	$350,000	$375,000	$90,000	$0
(b) Auxilary Systems	Vendor Quote (included in 1a)	$0	$0	$0	$0
(c) Instrumentation & Controls	0.10(1a + 1b)	$35,000	$37,500	$0	$0
(d) Structural Support	0.10(1a + 1b)	$35,000	$37,500	$0	$0
(e) Freight	0.05(1a + 1b + 1c + 1d)	$21,000	$22,500	$0	$0
(f) Florida Sales Tax	0.06(1a + 1b + 1c + 1d)	$25,200	$27,000	$5,400	$0
(g) Purchased Equipment Subtotal	(1a + 1b + 1c + 1d + 1e + 1f)	$466,200	$499,500	$95,400	$0
(2) Direct Installation Cost:	SNCR = .67(1g) ; FGR = .30(1g)	$312,354	$149,850	$0	$0
Total DCC	(1g + 2)	$778,554	$649,350	$95,400	$0
INDIRECT CAPITAL COSTS (ICC)					
(3) Indirect Installation Cost:					
(a) Technology License Fee	None	$50,000	$0	$0	$0
(b) Engineering & Supervision *	SNCR = .20(DCC) ; FGR = .10(DCC)	$155,711	$64,935	$0	$0
(c) Construction & Field Expenses *	SNCR = .20(DCC) ; FGR = .10(DCC)	$155,711	$64,935	$0	$0
(d) Construction & Contractor Fee *	SNCR = .10(DCC) ; FGR = .05(DCC)	$77,855	$32,468	$0	$0
(e) Contingencies *	SNCR = .20(DCC) ; FGR = .10(DCC)	$155,711	$64,935	$0	$0
(4) Other Indirect Cost:					
(a) Start–up & Testing *	SNCR = .15(DCC) ; FGR = .03(DCC)	$116,783	$19,481	$0	$0
(b) Model Study	Vendor Quotation	$110,000	$0	$0	$0
(c) Working Capital	30 Day DOC **	$35,178	$46,170	$0	$0
Total ICC	(3) + (4)	$856,949	$292,923	$0	$0
TOTAL CAPITAL INVESTMENT (TCI)	**DCC + ICC**	**$1,635,503**	**$942,273**	**$95,400**	**$0**
DIRECT OPERATING COST (DOC)					
(5) Operating Labor:					
(a) Operator	8,760 hr/yr @ $22/hr	$192,720	$192,720	$0	$0
(b) Supervisor	15% of operator cost	$28,908	$28,908	$0	$0
(6) Maintenance *	5% of total DCC	$38,928	$32,468	$4,770	$0
(7) Utilities (electrical)	$0.08/kw–hr				
(a) Ammonia Injection System	100 kw	$70,080	$0	$0	$0
(b) Recirculation Fan	428 kw	$0	$299,942	$0	$0
(8) Chemicals and Fuel					
(a) Ammonia	$250/ton	$91,500	$0	$0	$0
(b) Oil price difference	$0.15/gallon premium	$0	$0	$0	$450,000
Total DOC	(5) + (6) + (7) + (8)	$422,136	$554,038	$4,770	$450,000
INDIRECT OPERATING COST (IOC)					
(9) Overhead *	60% of (5) and (6)	$156,333	$152,457	$0	$0
(10) Property Taxes *	1% of TCI	$16,355	$9,423	$0	$0
(11) Insurance *	1% of TCI	$16,355	$9,423	$0	$0
(12) Administration *	2% of TCI	$32,710	$18,845	$0	$0
					$0
Total IOC	(9) + (10) + (11) + (12)	$221,754	$190,148	$0	$0
TOTAL OPERATING COST (TOC)	**DOC + IOC**	**$643,889**	**$744,186**	**$4,770**	**$450,000**
CAPITAL RECOVERY COST (CRC)	0.1627(TCI)	$266,096	$153,308	$15,522	$0
ANNUALIZED COST (AC)	**DOC + IOC + CRC**	**$909,986**	**$897,494**	**$20,292**	**$450,000**

Notes:

* Indicates that the cost factors are based on EPA's OAQPS Control Cost Manual, Fourth Edition.

** 30 days of direct operating costs (i.e. Total DOC/12)

1. Operating hours are 7,008 hr/yr on bagasse and 1,752 hr/yr on oil
2. Low–Nox burner equipment cost is premium over regular burner cost.

Table 5-7

Summary of Top-Down BACT Impact Analysis for NO_x

FEASIBLE CONTROL TECHNOLOGY	REMOVAL EFFICIENCY	CONTROLLED EMISSIONS TPY	EMISSION REDUCTION TPY (a)	AC $/YR	ACE $/Ton	ICE $/Ton	IE MW-hr	TOXICS IMPACT?	AEI?
SNCR	55%	185.9	227.2	909,986	4,006	121	876	Yes	Yes
FGR	30%	289.1	123.9	897,494	7,244	21,240	3,749	No	No
Low-NOx burner	20%	330.4	82.6	20,292	246	(20,809)	0	No	No
Low-nitrogen oil	15%	351.1	61.9	450,000	7,264	7,264	0	No	No
Baseline	0%	413.0	0	0	0	0	0	No	Yes

(a). Emissions reduction over baseline level of no controls (413 TPY of NOx).
NOx baseline emissions derived from AP-42 factors for oil and bagasse firing.

with fuel oil vendors, there is no special process to remove nitrogen from fuel oil, as there is for removing sulfur. Fuel oil nitrogen content does, however, seem to correlate fairly well with sulfur content. Thus, very-low-sulfur fuel oil should have less than 0.3% nitrogen by weight, although fuel oil vendors seem unwilling to guarantee this absolute value.

The preceding analysis has indicated that significant economic, environmental and energy costs are associated with the add-on control technology for NO_x. The estimated costs for add-on NO_x controls are unreasonable for fuel oil, particularly considering that it is not intended to burn oil for more than a 10% annual capacity factor, and that oil will be burned only if the supply of bagasse is not adequate.

Based on these considerations, **using low-nitrogen residual fuel oil (maximum of 0.3% nitrogen) as the compliance fuel, not to exceed 10% of the total annual heat input, represents BACT for NO_x emissions for the proposed boiler No. 7 when firing oil.**

Because of its utility in reducing NO_x emissions, along with its success record in the sugar industry, **overfire air, high excess air rates, and good combustion practices are proposed as BACT for NO_x emissions for the proposed boiler No. 7 when firing bagasse.**

The following considerations, described previously, support this proposed BACT:

- The current operations minimize NO_x emissions through use of overfire air, high excess air levels, and good combustion practices

- Sugar industry NO_x emissions are substantially less than fossil-fuel-fired steam generators, and thus NO_x control cost ($/ton of NO_x removed) will be higher for this unit than for those boilers

- Applications of alternative NO_x control technologies are technically and/or economically infeasible

The proposed NO_x BACT limit for boiler No. 7 is as follows:

- Bagasse-firing: 2.05 lb/ton of wet feed (about 0.26 lb/MM Btu)

- Oil-firing: 0.3 lb/MM Btu (low heat release)
0.4 lb/MM Btu (high heat release)

ATTACHMENT 4

CO Emission Limit Correspondence

C-4

UNITED STATES SUGAR CORPORATION
Post Office Drawer 1207 Clewiston, Florida 33440
Telephone: (813) 983-8121 Telex: 510-952-7753

October 8, 1990

Mr. David Knowles
Florida Department of Environmental
Regulation
2269 Bay Street
Fort Myers, Florida 33901-2896

RE: Hendry County - AP
U. S. Sugar Corporation
Clewiston Boiler No. 4
Permit AC26-126965 and
AO26-144701

Dear Mr. Knowles:

Following Mr. Philip R. Edward's request as per his letter of October 26, 1989, we are sending you Report No. 1376-A for CO Emissions from Boiler No. 4.

We would have wanted to make more tests in this boiler, but due to certain difficulties with the testing company and the early end of the crop due to the extensive freeze which we sustained last winter, we were unable to run a more adequate number of tests.

Results from these three (3) one (1) hour runs might not be representative of the actual range and average emissions from this boiler.

The purpose of this test as requested by Mr. Edwards is to help the Department determine a reasonable CO Emission Factor for boilers of this type. We suggest you consider and evaluate the results of the nine (9) runs carried out at our Bryant Boiler No. 5 as well, in making this determination.

Very truly yours,

UNITED STATES SUGAR CORPORATION

Peter Barquin
Administative Ass't. to
Senior Vice President
Sugar Houses

PB:jt
Enclosures

ATTACHMENT 5

CO BACT Analysis

5.4 BACT EVALUATION FOR CO AND VOC EMISSIONS

In this section, the available control technologies capable of reducing CO and VOC emissions produced from firing bagasse and residual oil will be identified and evaluated. Potential application of these technologies as BACT for the proposed spreader-stoker boiler, rated on oil at 255 MM Btu/hr, is discussed. Table 5-8 is a summary of the potential CO and VOC control technologies presented in this section.

The EPA BACT/LAER clearinghouse has no BACT determinations for CO or VOC emission from bagasse combustors or residual oil combustion in boilers. Historically, BACT and LAER emission limits for CO and VOC on bagasse and oil-fired boilers have been based on the use of good combustion practices, rather than add-on control systems.

In bagasse-fired boilers, the fuel characteristics and the combustion practices result in CO and VOC emissions that are somewhat high, relative to fossil-fuel fired boilers. Improving combustion would likely require improving fuel quality (e.g., lowering bagasse moisture content through drying), which would make use of this waste fuel uneconomical and result in higher fossil fuel usage. The use of FGR could theoretically reduce CO and VOC emissions by reburning a portion of the VOCs in the recirculated exhaust. The overall effectiveness of fluegas recirculation would be limited because:

- The extremely high particulate loading of the combustion gas and the abrasive nature of the flyash would make this system very unreliable
- This has never been applied to a bagasse combustor
- This technology would not be economically feasible, per the analysis done for NO_x control

Post-combustion VOC controls have not been applied to bagasse-fired boilers. Such common techniques as direct-flame incineration, catalytic oxidation, and carbon absorption are also inappropriate technologies for bagasse boilers for the same reasons as above.

The only technically feasible CO and VOC control technology for bagasse-fired boilers is good combustion practices.

Because of their utility in reducing CO and VOC emissions, along with its success record in the sugar industry, **good combustion practices are proposed as BACT for emissions for the proposed boiler No. 7 when firing bagasse or oil.**

Table 5-8

Summary of Potential CO and VOC control Technologies[1]

Control Technology	Typical Effic. (% CO)	Typical Effic. (% VOC)	In Service On Bagasse Combustors?	In Service On Other Combustion Sources?	Technically Feasible For This Combustor?
Direct-flame Oxidation	90-99	90-99	No	Yes	No[2]
Catalytic Oxidation	90-95	90-95	No	Yes	No[3]
Fluegas Recirculation	30-50%	30-50%	No	No	Yes[4]
Good Combustion Practices	15-50	15-50	Yes	Yes	Yes

Notes:

[1] Source: Air Pollution Engineering Manual, AWMA, 1992.

[2] Abrasive Particulate loading to high in combustor.

[3] Same as above.

[4] See discussion under NO_x control.

TEST REPORT ON THE PILOT TESTING PROGRAM

OF A

UNITED McGILL CORPORATION

DRY AND WET ELECTROSTATIC PRECIPITATOR SYSTEM

AT

UNITED STATES SUGAR CORPORATION

CLEWISTON, FLORIDA

PROCESS: BAGASSE FIRED BOILER

Project No. D-3029-9
U.S.S. Purchase Order No. W4-86044

Prepared by: Mark G. Demechko (DBL)
Mark G. Demechko
Manager, Field Service

Approved by: DBLuttenberger
David B. Luttenberger
Manager, Project Operations

UNITED McGILL CORPORATION

COLUMBUS, OHIO

JANUARY 1994

TABLE OF CONTENTS

STATEMENT OF CONFIDENTIALITY

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TEST RESULTS SUMMARY

The mobile electrostatic precipitator study conducted by United McGill Corporation (UMC) for U.S. Sugar Corporation (USS) in Clewiston, Florida investigated the suitability of a dry and wet electrostatic precipitator (EP) for collecting particulate in the exhaust from a bagasse fired boiler. The tests were conducted by Air Consulting & Engineering, Inc. at the direction of U.S. Sugar Corporation and UMC in two phases.

The purpose of phase I was to determine the collection capabilities of the precipitator when operating in a dry mode. When the EP is operated dry, the flue gas remains untreated and enters directly into the EP. Phase II involved the same testing as Phase I except the precipitator was operated in a wet mode. When the EP is operated wet, mist water is injected upstream of the precipitator's inlet transition and upstream of each electric field. The mist water is added to saturate the flue gas and assist in encapsulating the particulate.

A total of 14 pairs of simultaneous EP inlet/EP outlet Method 5 tests for total particulate (front half and back half) were reported. EPA Method 25-A and EPA-18 were used for VOC and CH_4. CO was measured using EPA-10 and NO_x was monitored using a Chemiluminescence Analyzer.

The first 5 tests involved Phase I dry EP testing. The phase I dry EP tests were run from January 10 to January 11, 1994. Collection efficiencies of the dry EP tests were as high as 93.6%. Based on the results of the Phase I dry EP testing, it was agreed by UMC and USS that a full scale dry precipitator would be extremely large and therefore not economically feasible to construct.

The next 9 tests involved Phase II wet EP testing. A spray lance was inserted in the duct work approximately 23' upstream of the EP inlet transition. Mist water was also injected upstream of each individual plate pack (electric field). The phase II wet EP tests were run from January 18 to January 20, 1994. Collection efficiencies of the wet EP tests were as high as 99.8%. Based on the results of the Phase II wet EP testing, UMC determined that a full scale wet precipitator with multiple fields will effectively control the emissions from a bagasse fired boiler similar to the #4 boiler tested.

A copy of the completed test configurations and a summary of the test results, along with process/EP operating conditions, are presented in Exhibits 3a and 3b.

I. INTRODUCTION

1.1. Background

U.S. Sugar Corporation produces raw sugar and molasses at their Clewiston, Florida plant. They burn the excess sugar cane, called bagasse, in four different boilers. U.S. Sugar requested that United McGill Corporation (UMC) perform an experimental investigation on the boiler #4 exhaust using the Mobile Precipitator (Mobile EP1). All tests were conducted using a slip stream of the boiler #4 exhaust between the I.D. fan and the exhaust stack.

1.2 Purpose and Objectives

The purpose of the investigation was to characterize the performance of the Mobile EP in removing pollutants from boiler gases' emissions. As part of the investigation, pollutant concentrations, emission rates, physical characteristics, and process conditions were determined. Specifically the objectives of the investigation were to:

- Determine whether or not an electrostatic precipitator of this or similar design will reduce particulate emissions from a bagasse fired boiler to less than 0.03 lbs per million BTU.
- Evaluate the ability of the air pollution control equipment to control the emissions, and the operating parameters affecting the collection efficiency.
- Gather sufficient data to permit UMC to design and cost a commercial electrostatic precipitator for a bagasse fired boiler of 350,000 lbs per hour output at 600 psi.

1.3 Process Description

The raw sugar and juices are extracted from sugar cane and the remaining cane is grounded to form a product called bagasse. The bagasse is transferred continuously to one of six boilers. Boiler #4 is the largest boiler and the exhaust of this boiler will be tested. Boiler #4 has six bagasse feed conveyors that operate continuously (excluding maintenance down-time).

U.S. Sugar currently operates at 300,000 lb/hr on the #4 bagasse fired boiler. The outlet emissions from this boiler are currently controlled by a wet scrubber to 0.15 lb/mm btu. The boiler is a Foster Wheeler travelling gate type, with Bunker C oil as the back-up fuel. Soot blowing usually occurs twice per eight hour shift. Grate raking also occurs twice per eight hour shift. Bagasse fuel interruptions occur frequently.

U.S. Sugar Corporation plans to install a new 350,000 lb/hr boiler and seeks to determine the feasibility of achieving an outlet concentration of 0.03 lb/mm btu (EPA Method 5) and an outlet opacity of 20% or less, as requested by the Florida Department of Environmental Protection.

II. EXPERIMENTAL WORK

2.1 Equipment Description

The mobile electrostatic precipitator was designed for pilot-scale studies. The unit utilizes four independent electrical fields in series and has an effective cross-sectional area of 25.4 square feet.

The mobile EP has an inlet and outlet transition from the twenty inch diameter inlet and outlet duct to the 25.4 square foot area of the collection chamber. A perforated plate is located in the inlet transition to evenly distribute the gas flow entering the collection chamber. A mist eliminator is located in the outlet transition to remove water droplets during wet operation and which also helps to maintain the gas flow distribution. The four electrical fields are located in series in the collection chamber. The outlet transition is followed by a vortex fan damper and an ID fan. Gas is exhausted through a fourteen-foot high outlet stack.

The mobile EP is equipped with two heated hoppers per field. The hoppers are equipped with vibrators. Two screw conveyors run the length of the unit and discharge through two sealed rotary valves located beneath the first field. Water headers are mounted in each field which are operated in two modes - misting and washing. Misting is used to ensure that the EP remains wet at all times. Washing is used to intermittently clean the collected material from the internals of the EP. The water headers were off during the dry EP testing. The wash headers were off and the mist headers were on during the wet EP testing.

A control panel, with instrumentation, allows manual control and monitoring of the unit's systems. A microprocessor allows automatic control of the field voltages/currents and system alarms.

The UMC mobile EP allows for different operational configurations. Flow through velocity and SCA can be changed to simulate different sized EPs, from the very small to the very large. With an upstream cooler or prequench gas, temperatures can be adjusted to any temperature, down to, and including, saturation. Test programs are designed to explore a wide range of parameters. If the results of testing under a given set of conditions (e.g. dry operation) are not practical or cost efficient, the testing parameters can be modified by varying inlet temperature, adding gas conditioning agents or converting to wet operation.

A drawing of the mobile EP is provided in Exhibit 1a. A pictorial drawing of the electrical fields is presented in Exhibit 1b. Specifications of the unit are presented in Exhibit 1c. The electrode spacing and needle arrangement used in Mobile EP1 are identical to those in a full scale UMC EP.

2.2 Data Collection Methods

For each phase of the testing program, the emissions from the process were measured by Air Consulting & Engineering, Inc. at the sample ports located upstream of Mobile EP 1 and at the outlet stack. Process emissions were characterized by temperature, moisture content, volumetric flow rate, molecular weight of the gas, and particulate concentration. The major controllable factors influencing collection efficiency in the mobile EP are gas moisture, gas volume, and the number of electrical fields energized. EP inlet and outlet USEPA Method 5 testing was performed simultaneously to determine the effects of the above variables on particulate matter collection efficiency. A drawing of the inlet duct arrangement is presented in Exhibit 1d.

The gas volume through the EP was changed by the static pressure at the induced draft fan near the EP outlet transition. The static pressure was controlled by adjustment of the fan damper located between the EP outlet/fan inlet. Opening the fan damper increased the gas volume and EP flow-through velocity while decreasing residence time.

The mobile EP is equipped with four electrically independent fields in series. From zero to four fields can be energized at one time. Increasing the number of fields increases the plate area available for particle collection.

The Phase I dry EP testing lasted from January 10 to January 11. The Phase II wet EP testing lasted from January 18 to January 20. Daily logs were filled out regularly and are included in Appendix 1. Field power levels were kept at a maximum during testing with continuous operation. Some variation in these levels did occur with changes in the water misting rate during Phase II testing. A detailed log of the temperatures, EP inlet static pressures, water mist rates, and power levels was maintained during the operation of the unit and are included in Appendix 2.

To help evaluate the long-term performance reliability, periodic internal inspections were made. Four samples of the dry particulate of Phase I dry EP testing were taken from the EP discharge. These samples were sent to Southern Research Institute for a resistivity analysis. Dry particulate samples were also sent to Bowser Morner for a carbon analysis. The results of these analyses can be found in Exhibit 2d and 2e respectively.

In addition to taking dry EP test samples, daily water samples were taken during the phase II wet EP testing. Samples were taken daily at the EP mist water supply and at the EP discharge. A sample was also taken of the scrubber #4 lance supply as well as the scrubber #4 recirculated/blow down water. A summary of the water samples taken can be found in Exhibit 2a. The locations of where the scrubber water samples were taken is shown in Exhibit 2b.

All water samples were sent to Savannah Laboratories & Environmental Services, Inc. and were analyzed for Chloride, hardness, pH, total dissolved solids, and total suspended solids. The chemical analysis of the water samples can be found in Exhibit 2c.

III. DISCUSSION OF RESULTS AND CONCLUSIONS

3.1 Phase I Dry EP Performance

The lowest total particulate matter (PM) emissions level achieved during phase I was 0.0635 gr/dscf. The target emission goal of 0.03 lbs/mm btu of boiler fuel, which equates to approximately 0.01 gr/dscf, was not achieved. The maximum achievable removal efficiency was 93.6% based on lbs/hr. A copy of the completed test configurations and a summary of the test results, along with process/EP operating conditions, are presented in Exhibits 3a and 3b.

The low performance of the dry electrostatic precipitator testing is similar to UMC's past experiences with some coal fired boilers in which the ash contained high carbon content, typically greater than 25%. This high carbon content typically results in a low resistivity. Low resistivity creates problems with particle reentrainment since the precipitator is very sensitive to factors affecting reentrainment such as rapping and flow distribution.

High levels of opacity could be seen shortly after the plates were rapped and after sootblowing occurred. The high opacity excursions are a result of the low resistivity associated with the dust particles. This low resistivity causes the particles the become easily dislodged from the plate with minimal effort. If the combustion efficiency in the boiler increased, the carbon level of the particles would decrease, making the particles easier to collect and hold on the plate surface, thus, more difficult to reentrain. You will note in Exhibit 2e the carbon content of the ash sampled varied from 17.5%-50.6%, indicating an inconsistency of the fuel source, combustion, or both.

During the phase I dry EP testing, red hot ash was noticed falling out of the rotary valve into the dust collection bucket where it would smolder. This occurrence is common with high carbon content ash that is exposed to high levels of oxygen.

The results of the phase I testing indicate that an extremely large precipitator with a very low face velocity would be required to achieve the 0.03 lb/mm btu outlet level desired, if the ash characteristics of the proposed new boiler remain the same as the boiler tested. A full scale dry precipitator may not be economically feasible and might be suspectable to performance degradation and fire hazards during process changes and upset conditions. Greatly improving the combustion of the bagasse would lower the carbon content of the ash which would make a dry precipitator more practical.

3.2 Phase II Wet EP Performance

The outlet concentrations during phase II testing ranged from a low of 0.0021 gr/dscf to 0.0081 gr/dscf. The target emission goal of 0.03 lbs/mm btu of boiler heat input, which equates to approximately 0.01 gr/dscf, was achieved. The maximum removal efficiency achieved was 99.8% based on lbs/hr. A copy of the completed test configurations and a summary of the test results, along with process/EP operating conditions, are presented in Exhibits 3a and 3b.

The phase II testing was successful in reducing the emissions to the desired outlet level. The high performance level of the wet precipitator is a result of collecting material from a saturated gas stream which effectively eliminated reentrainment.

With only two fields active, the wet EP testing resulted in a 99.3% efficiency. With only two fields active and a soot blow taking place, the wet EP testing resulted in 99.4% efficiency. The soot blowing basically has no affect on the collection efficiency of the EP. The wet EP has a very low sensitivity to process upsets and has a low fire potential when compared to a dry precipitator.

The buildup on the plates after the Phase II wet EP testing was minimal due to the constant spray of water applied to the plates during testing. The buildup that did exist was located in areas where water was not applied or where nozzles were plugged. The wet buildup that remained in the precipitator after the tests was easily removed from the plates with the low pressure spray of a garden hose.

3.3 Wet EP Collection Versus Dry EP Collection

The principal factors which effect particulate collection efficiency in an electrostatic precipitator are plate area, aspect ratio, velocity, particle mass, and charge.

In dry EP operation, the charge on a particle is primarily dependent on its electrical characteristics. For low resistivity dusts, which both accept and loose charge easily, velocity and aspect ratio must be low, to prevent reentrainment after any disturbance. This results in a large EP with a high SCA. Therefore, in dry EP operation, the resistivity (assuming the same size particle mass) is the principle factor affecting performance.

In wet EP operation the gas stream is saturated with water, both in vapor and liquid state. The liquid droplets provide sites which attack and absorb dust particles. Thus increasing the mass of the particles to be collected. Further, instead of collecting small, low resistivity particles, the precipitator is now primarily collecting water. Water is a polar molecule which is very easy to collect and likely to retain its charge. Because it is a liquid, it continually runs off the plate and no rapping is required. This virtually eliminates the phenomenon of rapping puffs. This results in a precipitator with higher velocities and aspect ratios, smaller size and SCA. In wet EP operation, the mass and electrical characteristics of water droplets are the principle factors affecting performance.

MOBILE DRY EP TEST RESULTS SUMMARY

Test No.	Inlet acfm	Inlet lb/hr	Outlet lb/hr	Inlet scfmd	Inlet gr/dscf	Outlet gr/dscf	Efficiency
1	2991.1	14.79	0.993	1808.3	0.9542	0.0641	93.3%
3	2847.7	12.57	0.895	1599.9	0.9166	0.0653	92.9%
7	4595.6	27.25	4.114	2427.9	1.3094	0.1977	84.9%
8	4745.0	21.09	1.347	2474.7	0.9943	0.0635	93.6%
9	4467.9	23.41	4.693	2326.8	1.1738	0.2353	80.0%

MOBILE WET EP TEST RESULTS SUMMARY

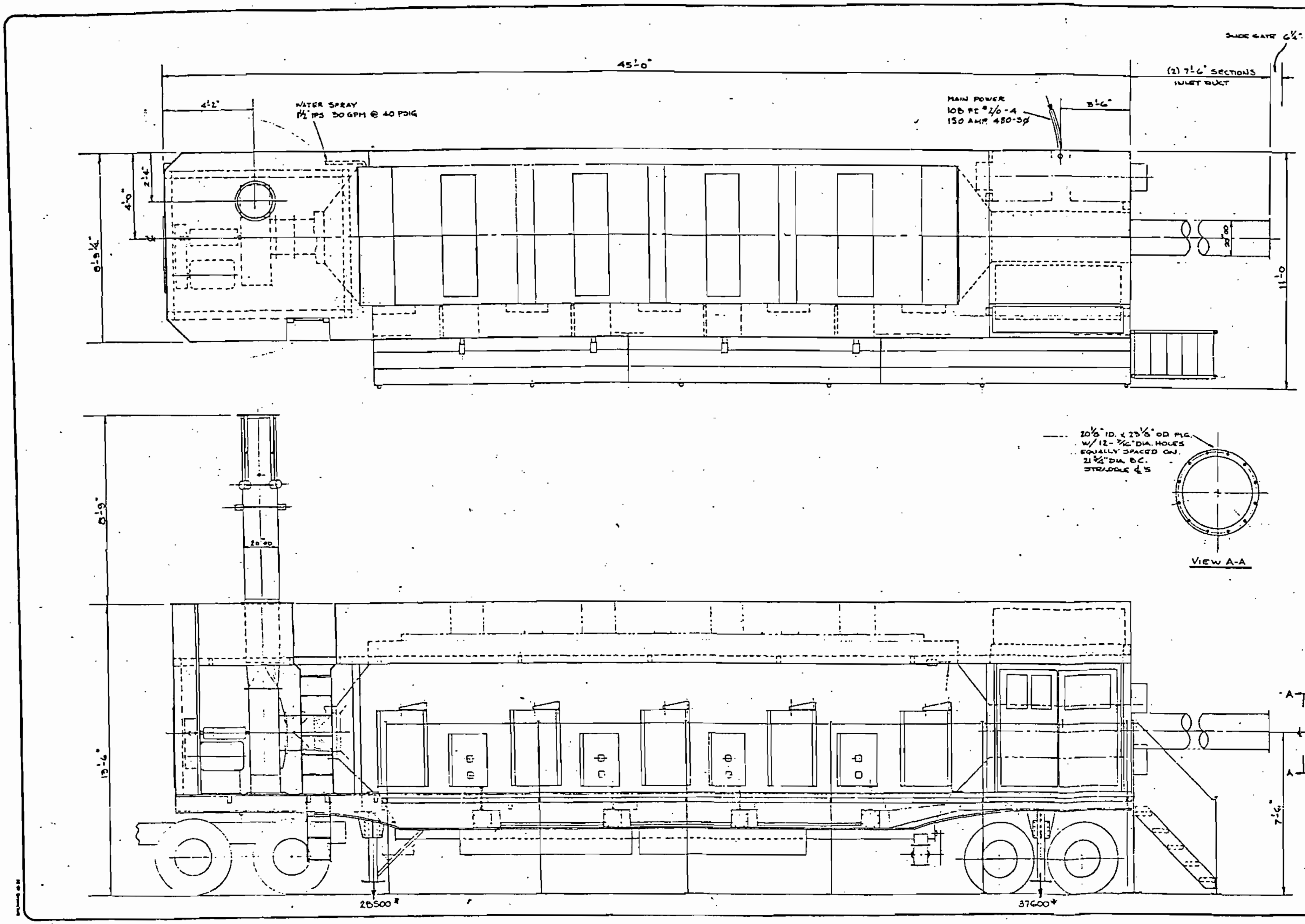
Test No.	Inlet acfmd	Inlet lb/hr	Outlet lb/hr	Inlet scfmd	Inlet scfmw	Inlet gr/dscf	Outlet gr/dscf	Efficiency
1	3879.1	50.76	0.137	2552.0	2923.4	2.3205	0.0063	99.7%
2	3533.5	39.35	0.127	2361.9	2783.9	1.9437	0.0063	99.7%
3	3250.7	51.68	0.105	2172.5	2538.2	2.7752	0.0056	99.8%
4	5580.9	36.30	0.066	3621.0	4294.9	1.1696	0.0021	99.8%
5	5635.8	33.22	0.227	3588.7	4285.1	1.0800	0.0074	99.3%
6	5940.3	29.52	0.125	3762.2	4429.0	0.9154	0.0039	99.6%
7	5834.5	31.13	0.220	3716.2	4481.5	0.9773	0.0069	99.3%
8	5827.4	29.83	0.258	3701.1	4413.4	0.9403	0.0081	99.1%
9	5707.7	33.96	0.190	3613.0	4371.2	1.0966	0.0061	99.4%

EXHIBIT 1

PROJECT AND EQUIPMENT SPECIFICATIONS

EXHIBIT 1a

Drawing of Mobile EP



GENERAL ARRANGEMENT 4-25
MOBILE PRECIPITATOR

United McGill Corporation

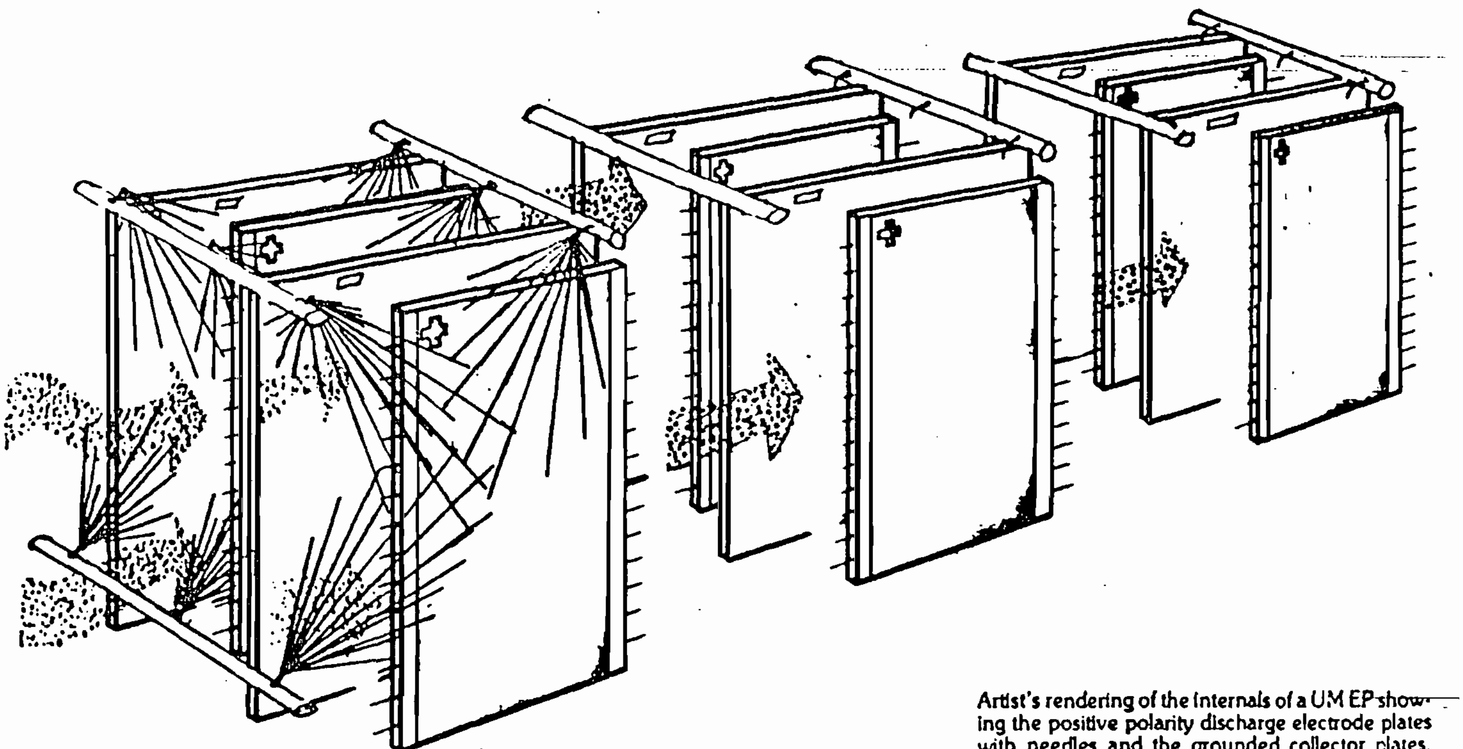
DRAWN	MS/AY	10-4-01
CHECKED		
APPROVED		
APPROVED		

SCALE V.:
JOB NO P-1515-90
CUST NO
DRAWING NO 110-95
SHEET
REV 0

EXHIBIT 1b

Drawing of Electrode Plates

EXHIBIT 1b - ELECTRICAL FIELD AND SPRAY HEADER ARRANGEMENT



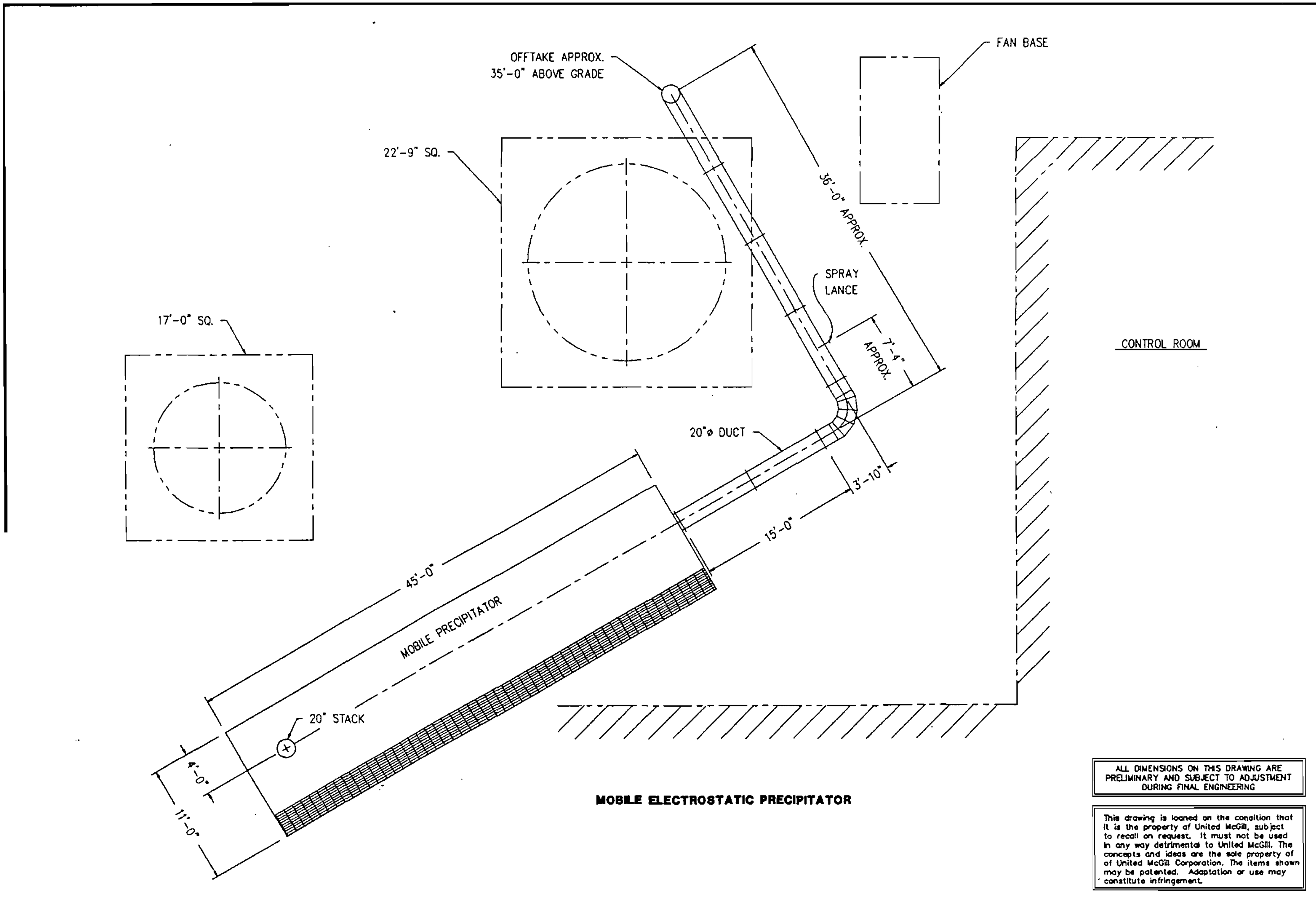
Artist's rendering of the internals of a UM EP showing the positive polarity discharge electrode plates with needles and the grounded collector plates. Three fields in series are shown.

Specifications for Mobile EP 1

1.	Number of grounded collector plates per field:	10
2.	Number of high voltage collector plates per field:	9
3.	Height of field:	5'5"
4.	Width of field:	5'5"
5.	Effective EP cross-sectional area:	25.4 square feet
6.	Total number of needles per field:	684

EXHIBIT 1d

Inlet Duct Arrangement



MOBILE ELECTROSTATIC PRECIPITATOR

ALL DIMENSIONS ON THIS DRAWING ARE PRELIMINARY AND SUBJECT TO ADJUSTMENT DURING FINAL ENGINEERING

GENERAL ARRANGEMENT
MOBILE ELCTROSTATIC PRECIPITATOR
U.S. SUGAR CORPORATION

United McGill Corporation

DRAWN:	P.Lng 3/11/94
CHECKED:	
APPROVED:	
APPROVED:	

SCALE: NONE
JOB NO. D-3029-0
CUST. NO.
DRAWING 33029-0000 SHEET 1 REV

Plot Scale: 1= 40
Plot Date:

EXHIBIT 2

CHARACTERISTICS OF THE SOURCE EMISSIONS

EXHIBIT 2a

Water Sample Summary

U.S. SUGAR WATER SAMPLES

WATER SAMPLE DESCRIPTION	DATE TAKEN	TIME TAKEN
WEP Supply	1/18/94	1015 hrs
WEP Test 1 Discharge	1/18/94	1015 hrs
WEP Test 2 Discharge	1/18/94	1335 hrs
WEP Test 3 Discharge	1/18/94	1625 hrs
WEP Supply	1/19/94	1635 hrs
WEP Test 4 Discharge	1/19/94	1130 hrs
WEP Test 5 Discharge	1/19/94	1422 hrs
WEP Test 6 Discharge	1/19/94	1640 hrs
WEP Test 7 Discharge	1/20/94	827 hrs
WEP Supply	1/20/94	837 hrs
WEP Test 8 Discharge	1/20/94	1030 hrs
WEP Test 9 Discharge	1/20/94	1236 hrs
Scrubber #4 Supply Water	1/21/94	1138 hrs
Scrubber #4 Discharge Water	1/21/94	1311 hrs

EXHIBIT 2b

Location of Scrubber Water Sample Points

U. S. Sugar, Clewiston FL, Existing Water Treatment System

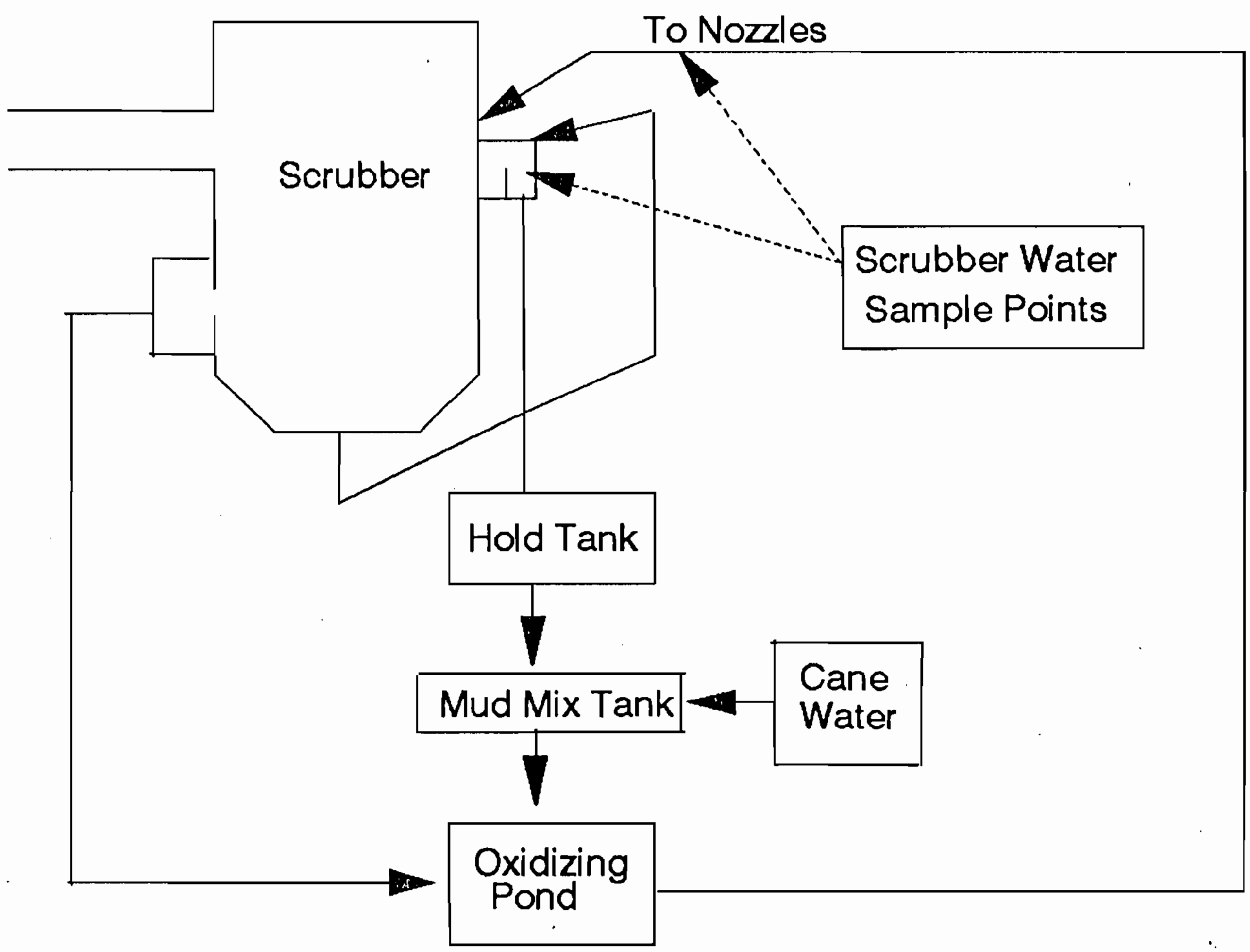


EXHIBIT 2c

Chemical Analysis of the Water

SAVANNAH LABORATORIES
& ENVIRONMENTAL SERVICES, INC.

414 SW 12th Avenue • Deerfield Beach, Florida 33442 • (305) 421-7400 • Fax (305) 421-2584

LOG NO: D4-90340

Received: 21 JAN 94

Mr. Mark Demechko
United McGill
1779 Refugee Road
Columbus, OH 43216

Purchase Order: #CP-94-0202-S

Project: #D-3029-9
Sampled By: G. Roush

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE SAMPLED
90340-1	WEP Supply	01-18-94
90340-2	WEP Test 1 Disch	01-18-94
90340-3	WEP Test 2 Disch	01-18-94
90340-4	WEP Test 3 Disch	01-18-94
90340-5	WEP Supply (01.19.94)	01-19-94

PARAMETER	90340-1	90340-2	90340-3	90340-4	90340-5
Chloride					
Chloride, mg/l	90	160	230	160	87
Date Analyzed	01.31.94	01.31.94	01.31.94	01.31.94	01.31.94
Method Number	EPA 325.3	EPA 325.3	EPA 325.3	EPA 325.3	EPA 325.3
Hardness, Total by calculation					
Hardness as CaCO3, mg/l	70	520	600	270	150
Date Calculated	02.01.94	02.01.94	02.01.94	02.01.94	02.01.94
Method Number	EPA 314A	EPA 314A	EPA 314A	EPA 314A	EPA 314A
pH					
pH , units	9.91	8.74	8.74	8.33	9.54
Date Analyzed	01.24.94	01.24.94	01.24.94	01.24.94	01.24.94
Method Number	EPA 150.1	EPA 150.1	EPA 150.1	EPA 150.1	EPA 150.1
Solids, Total Dissolved					
Solids, Total Dissolved, mg/l	310	880	1400	790	370
Date Analyzed	01.25.94	01.25.94	01.25.94	01.25.94	01.25.94
Method Number	EPA 160.1	EPA 160.1	EPA 160.1	EPA 160.1	EPA 160.1
Solids, Total Suspended					
Solids, Total Suspended, mg/l	<5.0	2900	6500	2900	<5.0
Date Analyzed	01.25.94	01.25.94	01.25.94	01.25.94	01.25.94
Method Number	EPA 160.2	EPA 160.2	EPA 160.2	EPA 160.2	EPA 160.2

SL SAVANNAH LABORATORIES
& ENVIRONMENTAL SERVICES, INC.

414 SW 12th Avenue • Deerfield Beach, Florida 33442 • (305) 421-7400 • Fax (305) 421-2584

LOG NO: D4-90340

Received: 21 JAN 94

Mr. Mark Demechko
United McGill
1779 Refugee Road
Columbus, OH 43216

Purchase Order: #CP-94-0202-S

Project: #D-3029-9
Sampled By: G. Roush

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE SAMPLED
90340-6	WEP Test 4 Disch	01-19-94
90340-7	WEP Test 5 Disch	01-19-94
90340-8	WEP Test 6 Disch	01-19-94
90340-9	WEP Test 7 Disch	01-20-94
90340-10	WEP Supply (01.20.94)	01-20-94

PARAMETER	90340-6	90340-7	90340-8	90340-9	90340-10
Chloride					
Chloride, mg/l	180	200	200	160	87
Date Analyzed	01.31.94	01.31.94	01.31.94	01.31.94	01.31.94
Method Number	EPA 325.3	EPA 325.3	EPA 325.3	EPA 325.3	EPA 325.3
Hardness, Total by calculation					
Hardness as CaCO3, mg/l	790	460	570	490	89
Date Calculated	02.01.94	02.01.94	02.01.94	02.01.94	02.01.94
Method Number	EPA 314A	EPA 314A	EPA 314A	EPA 314A	EPA 314A
pH					
pH , units	8.98	8.83	8.74	8.80	9.61
Date Analyzed	01.24.94	01.24.94	01.24.94	01.24.94	01.24.94
Method Number	EPA 150.1	EPA 150.1	EPA 150.1	EPA 150.1	EPA 150.1
Solids, Total Dissolved					
Solids, Total Dissolved, mg/l	880	1100	1200	960	370
Date Analyzed	01.25.94	01.25.94	01.26.94	01.26.94	01.26.94
Method Number	EPA 160.1	EPA 160.1	EPA 160.1	EPA 160.1	EPA 160.1
Solids, Total Suspended					
Solids, Total Suspended, mg/l	3000	1700	2700	2300	<5.0
Date Analyzed	01.25.94	01.25.94	01.25.94	01.25.94	01.25.94
Method Number	EPA 160.2	EPA 160.2	EPA 160.2	EPA 160.2	EPA 160.2

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& ENVIRONMENTAL SERVICES, INC.

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LOG NO: D4-90340

Received: 21 JAN 94

Mr. Mark Demechko
United McGill
1779 Refugee Road
Columbus, OH 43216

Purchase Order: #CP-94-0202-S

Project: #D-3029-9
Sampled By: G. Roush

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE SAMPLED
90340-11	WEP Test 8 Disch	01-20-94
90340-12	WEP Test 9 Disch	01-20-94

PARAMETER	90340-11	90340-12
Chloride		
Chloride, mg/l	180	170
Date Analyzed	01.31.94	01.31.94
Method Number	EPA 325.3	EPA 325.3
Hardness, Total by calculation		
Hardness as CaCO3, mg/l	500	330
Date Calculated	02.01.94	02.01.94
Method Number	EPA 314A	EPA 314A
pH		
pH , units	8.63	8.61
Date Analyzed	01.24.94	01.24.94
Method Number	EPA 150.4	EPA 150.1
Solids, Total Dissolved		
Solids, Total Dissolved, mg/l	850	950
Date Analyzed	01.26.94	01.26.94
Method Number	EPA 160.1	EPA 160.1
Solids, Total Suspended		
Solids, Total Suspended, mg/l	2300	2000
Date Analyzed	01.25.94	01.25.94
Method Number	EPA 160.2	EPA 160.2

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LOG NO: D4-90340

Received: 21 JAN 94

Mr. Mark Demechko
United McGill
1779 Refugee Road
Columbus, OH 43216

Purchase Order: #CP-94-0202-S

Project: #D-3029-9
Sampled By: G. Roush

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES
90340-13	Lab Blank
90340-14	Accuracy - % Recovery (Mean)
90340-15	Precision - Relative % Difference
90340-16	Detection Limit

PARAMETER	90340-13	90340-14	90340-15	90340-16
Chloride				
Chloride, mg/l	<1.0	99 %	0 %	1.0
Date Analyzed	01.31.94	---	---	01.31.94
Method Number	EPA 325.3	---	---	EPA 325.3

Method References: EPA 600/4-79-020 and
Standard Methods.

Paul Canevaro

Final Page Of Report

SAVANNAH LABORATORIES
& ENVIRONMENTAL SERVICES, INC.

414 SW 12th Avenue • Deerfield Beach, Florida 33442 • (305) 421-7400 • Fax (305) 421-2584

LOG NO: D4-90363

Received: 24 JAN 94

Mr. Mark Demechko
United McGill
1779 Refugee Road
Columbus, OH 43216

Purchase Order: #CP-94-0202-S

Project: #D-3029-9
Sampled By: G.Roush

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE SAMPLED
90363-1	Scrubber #4 Supply Water	01-21-94
90363-2	Scrubber #4 Discharge Water	01-21-94

PARAMETER	90363-1	90363-2
Chloride		
Chloride, mg/l	160	310
Date Analyzed	02.01.94	02.01.94
Method Number	EPA 325.3	EPA 325.3
pH		
pH , units	8.04	8.22
Date Analyzed	01.24.94	01.24.94
Method Number	EPA 150.1	EPA 150.1
Solids, Total Dissolved		
Solids, Total Dissolved, mg/l	1200	2200
Date Analyzed	01.27.94	01.27.94
Method Number	EPA 160.1	EPA 160.1
Solids, Total Suspended		
Solids, Total Suspended, mg/l	<5.0	3700
Date Analyzed	01.24.94	01.24.94
Method Number	EPA 160.2	EPA 160.2

SL SAVANNAH LABORATORIES
& ENVIRONMENTAL SERVICES, INC.

414 SW 12th Avenue • Deerfield Beach, Florida 33442 • (305) 421-7400 • Fax (305) 421-2584

LOG NO: D4-90363

Received: 24 JAN 94

Mr. Mark Demechko
United McGill
1779 Refugee Road
Columbus, OH 43216

Purchase Order: #CP-94-0202-S

Project: #D-3029-9
Sampled By: G.Roush

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES
90363-3	Lab Blank
90363-4	Accuracy - % Recovery (Mean)
90363-5	Precision - Relative % Difference
90363-6	Detection Limit

PARAMETER	90363-3	90363-4	90363-5	90363-6
Chloride				
Chloride, mg/l	<1.0	106 %	0.94 %	1.0
Date Analyzed	02.01.94	---	---	---
Method Number	EPA 325.3	---	---	---

Method Reference: EPA 600/4-79-020.

Paul Canevaro

Paul Canevaro

Final Page Of Report

EXHIBIT 2d

Resistivity Analysis of the Particulate

Southern Research Institute

February 3, 1994

FAX: 614/445-8759 - 3 Pages

Mr. T. J. Shay
United McGill Corporation
1779 Refugee Road
P. O. Box 820
Columbus, OH 43216-0820

Dear Mr. Shay:

Measurements of electrical resistivity were made on four samples you provided under purchase order CP-94-0306-C. The measurements were made in ascending temperature mode generally according to IEEE 548-1984, although reduced electric fields had to be used with some of the samples as described below. A moisture content of 21.5% was maintained in the test environment during the measurement. Prior to the measurement, the samples were cleaned with a 60 mesh sieve to eliminate large chunks which could invalidate the resistivity test. The four samples run are identified as:

1. Test 1, 1/10/94
2. Test 8, 1/11/94
3. Test 8, 1/11/94 (Sample ignited prior to resistivity measurement)
4. Test 10, 1/12/94

Visual inspection suggested that all of the samples contained large quantities of unburned carbonaceous material. Since high carbon content often results in resistivity data which are atypical of fly ash, one sample was ignited at 750°C in air to eliminate any carbon prior to resistivity measurement. Ignition was first attempted with the portion of the Test 10 sample which remained after the resistivity cell was loaded with the unignited material. Both the remaining as-received sample and the +60 mesh size fraction removed from the material loaded in the resistivity cell were ignited and had very large loss-on-ignition (LOI) mass fractions. The as-received Test 10 sample had an LOI of 62%, while the +60 mesh fraction lost 74% of its mass. The result of these large losses was that insufficient material remained from the ignited Test 10 sample for a resistivity measurement.

Ignition was repeated on the remainder of the Test 8 sample, which was a much larger sample than Test 10. Only the as-received portion of the Test 8 sample was ignited and it had a much lower indicated LOI at 19.8%. However, almost half (45%) of the ignited Test 8 sample was larger than 60 mesh and appeared to be mostly sand. This is different from the Test 10 sample which had little material larger than 60 mesh after ignition. The sand was removed from the ignited Test 8 sample before the resistivity measurement.

The measured resistivity of the four samples is shown as a function of temperature in Figure 1. Significantly different results were obtained with the as-received and ignited samples. The three as-received samples indicated very low resistivity which was essentially constant over the measured temperature range. These resistivities are so low that the electric field in the sample layer had to be reduced from the standard 4 kV/cm to 40 volts/cm to avoid excessive current levels. This is typical behavior in the laboratory device for dusts with very high carbon contents. If this very low resistivity is actually indicative of the particles collected in the ESP, electrical reentrainment could severely degrade ESP performance.

The ignited sample, shown by the open triangles on Figure 1, produced a resistivity-temperature relationship typical of low resistivity fly ash. The peak of the curve was just below 5×10^{10} ohm-cm at approximately 400°F and values in the 10^{9} ohm-cm range are seen at typical cold-side temperatures (290-325°F). At cold-side temperatures, this dust should not limit ESP electrical operation and very good performance should result in the absence of other problems. Essentially identical results were obtained for the ignited sample at 4 kV/cm and 40 volts/cm.

I hope these data meet your needs. If I can provide additional assistance, please don't hesitate to call.

Sincerely,

Carl

E. C. Landham, Jr.
Supervisor, Control Systems Analysis

SRI-ENV-94-098-7272.33

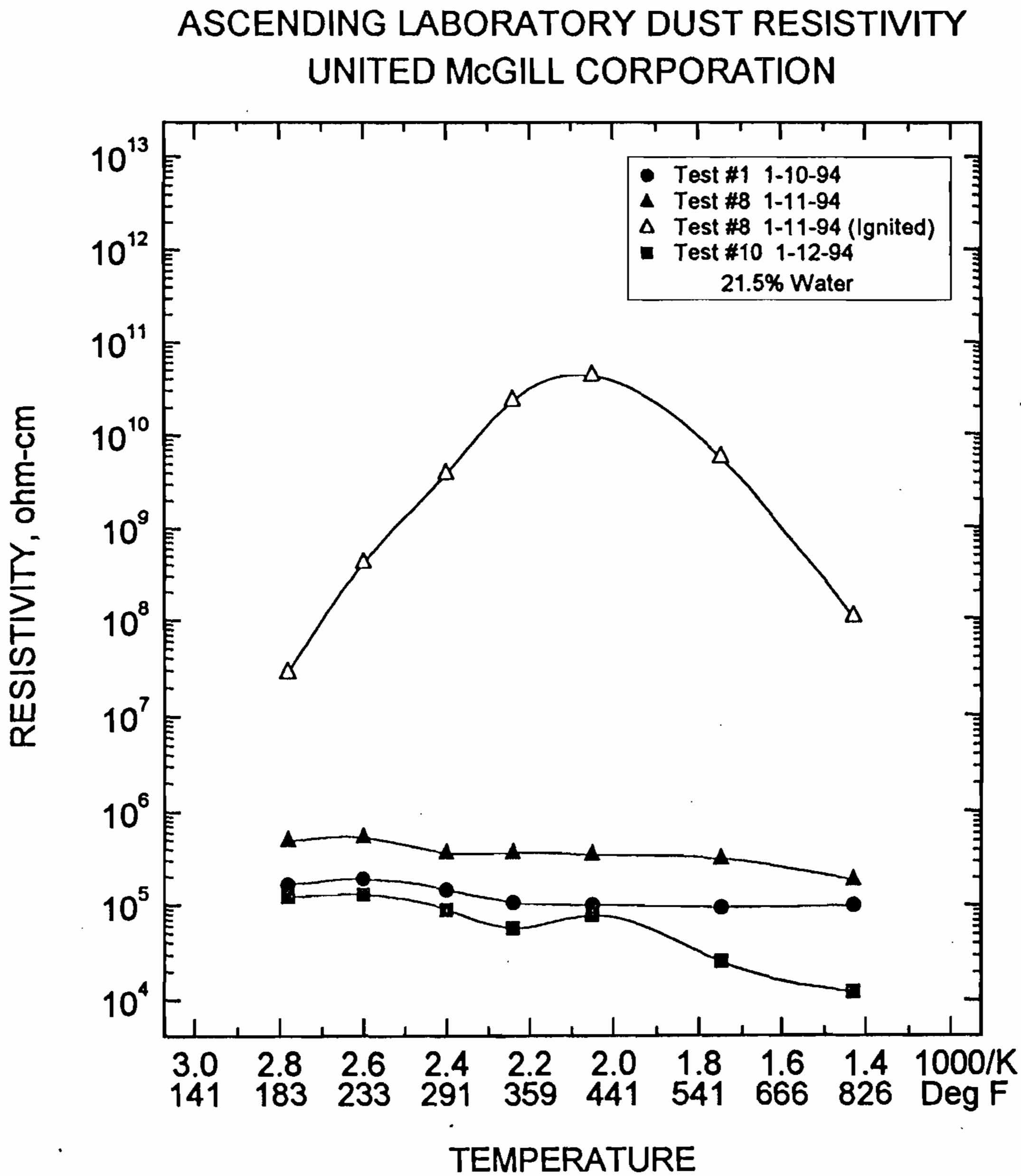


Figure 1. Ascending-Temperature Dust Resistivity by IEEE 548-1984.

EXHIBIT 2e

Carbon Analysis of the Particulate

BOWSER MORNER.

Shipping: 4518 Taylorsville Rd. • Dayton, OH 45424 Mailing: P.O. Box 51 • Dayton, OH 45401
513/236-8805

LABORATORY REPORT

TO: David T Poole
UNITED MCGILL CORPORATION
1779 Refugee Road
PO Box 820
Columbus, OH 43216-0820

Report Date: 02/02/94
Job Number : 94010200
Group No. : 4906
Sample No. : 401208
Auth/P.O.# :

Sample Identification: 01/10/94 - TEST #1

Date Received: 01/28/94

Analysis Description	Result	Units
Carbon	20.3	%

Submitted by,

Donald G Duncan

Donald G. Duncan, Asst.Manager
General Chemistry Laboratory

D1/3752/

BOWSER MORNER.

Shipping: 4518 Taylorsville Rd. • Dayton, OH 45424 Mailing: P.O. Box 51 • Dayton, OH 45401
513/236-8805

LABORATORY REPORT

TO: David T Poole
UNITED MCGILL CORPORATION
1779 Refugee Road
PO Box 820
Columbus, OH 43216-0820

Report Date: 02/02/94
Job Number : 94010200
Group No. : 4906
Sample No. : 401209
Auth/P.O.# :

Sample Identification: 01/08/94 - TEST #2

Date Received: 01/28/94

Analysis Description	Result	Units
Carbon	21.4	%

Submitted by,

Donald G. Duncan

Donald G. Duncan, Asst.Manager
General Chemistry Laboratory

01/3752/

BOWSER MORNER.

Shipping: 4518 Taylorsville Rd. • Dayton, OH 45424 Mailing: P.O. Box 51 • Dayton, OH 45401
513/236-8805

LABORATORY REPORT

TO: David T Poole
UNITED MCGILL CORPORATION
1779 Refugee Road
PO Box 820
Columbus, OH 43216-0820

Report Date: 02/02/94
Job Number : 94010200
Group No. : 4906
Sample No. : 401210
Auth/P.O.# :

Sample Identification: 01/11/94 - TEST #8

Date Received: 01/28/94

Analysis Description	Result	Units
Carbon	17.5	%

Submitted by,

Donald G. Duncan

Donald G. Duncan, Asst.Manager
General Chemistry Laboratory

01/3752/

BOWSER MORNER.

Shipping: 4518 Taylorsville Rd. • Dayton, OH 45424 Mailing: P.O. Box 51 • Dayton, OH 45401
513/236-8805

LABORATORY REPORT

TO: David T Poole
UNITED MCGILL CORPORATION
1779 Refugee Road
PO Box 820
Columbus, OH 43216-0820

Report Date: 02/02/94
Job Number : 94010200
Group No. : 4906
Sample No. : 401211
Auth/P.O.# :

Sample Identification: 01/12/94 - TEST #10

Date Received: 01/28/94

Analysis Description	Result	Units
Carbon	50.6	%

Submitted by,

Donald G Duncan

Donald G. Duncan, Asst.Manager
General Chemistry Laboratory

D1/3752/

EXHIBIT 3

EMISSIONS MEASUREMENTS AND EXPERIMENTAL CONDITIONS

EXHIBIT 3a

Completed Test Schedule

MOBILE DRY EP TEST CONFIGURATION SUMMARY

TEST NO.	DATE	TIME	Active Fields	Inlet ACFM	EP Velocity	Events During Test
1	1/10/94	1216 - 1316	1, 2, 3	2991.1	1.96 FPS	Field 1 & 2 rapped
3	1/10/94	1535 - 1635	1	2847.7	1.87 FPS	None
7	1/11/94	1300 - 1400	1, 2, 3, 4	4595.6	3.02 FPS	Field 2 rapped and soot blow
8	1/11/94	0958 - 1058	1, 2, 3, 4	4745.0	3.11 FPS	None
9	1/11/94	1550 - 1650	1, 2, 3, 4	4467.9	2.93 FPS	Field 1 & 3 rapped

MOBILE WET EP TEST CONFIGURATION SUMMARY

TEST NO.	DATE	TIME	Active Fields	Inlet ACFMD	EP Velocity	Events During Test
1	1/18/94	1007 - 1146	1, 2, 3, 4	3879.1	2.55 FPS	1 duct nozzle spraying downstream
2	1/18/94	1326 - 1427	2, 3, 4	3533.5	2.32 FPS	1 duct nozzle spraying downstream
3	1/18/94	1558 - 1659	2, 3	3250.7	2.13 FPS	1 duct nozzle spraying downstream
4	1/19/94	1116 - 1217	1, 2, 3, 4	5580.9	3.66 FPS	1 duct nozzle spraying downstream
5	1/19/94	1347 - 1449	2, 3	5635.8	3.70 FPS	1 duct nozzle spraying downstream
6	1/19/94	1608 - 1710	2, 3, 4	5940.3	3.90 FPS	2 duct nozzles: up & downstream
7	1/20/94	0815 - 0916	2, 3	5834.5	3.83 FPS	2 duct nozzles: up & downstream
8	1/20/94	1015 - 1116	2	5827.4	3.82 FPS	2 duct nozzles: up & downstream
9	1/20/94	1210 - 1311	2, 3	5707.7	3.75 FPS	2 duct nozzles: up & downstream; Soot Blow

EXHIBIT 3b

Test Result Summaries

MOBILE DRY EP TEST RESULTS SUMMARY

TEST NO.	Inlet ACFM	Inlet LB/HR	Outlet LB/HR	Inlet SCFMD	Inlet GR/DSCF	Outlet GR/DSCF
1	2991.1	14.79	0.993	1808.3	0.9542	0.0641
3	2847.7	12.57	0.895	1599.9	0.9166	0.0653
7	4595.6	27.25	4.114	2427.9	1.3094	0.1977
8	4745.0	21.09	1.347	2474.7	0.9943	0.0635
9	4467.9	23.41	4.693	2326.8	1.1738	0.2353

MOBILE WET EP TEST RESULTS SUMMARY

TEST NO.	Inlet ACFMD	Inlet LB/HR	Outlet LB/HR	Inlet SCFMD	Inlet SCFMW	Inlet GR/DSCF	Outlet GR/DSCF
1	3879.1	50.76	0.137	2552.0	2923.4	2.3205	0.0063
2	3533.5	39.35	0.127	2361.9	2783.9	1.9437	0.0063
3	3250.7	51.68	0.105	2172.5	2538.2	2.7752	0.0056
4	5580.9	36.30	0.066	3621.0	4294.9	1.1696	0.0021
5	5635.8	33.22	0.227	3588.7	4285.1	1.0800	0.0074
6	5940.3	29.52	0.125	3762.2	4429.0	0.9154	0.0039
7	5834.5	31.13	0.220	3716.2	4481.5	0.9773	0.0069
8	5827.4	29.83	0.258	3701.1	4413.4	0.9403	0.0081
9	5707.7	33.96	0.190	3613.0	4371.2	1.0966	0.0061

APPENDIX 1

Emission Testing Daily Logs

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1-7-94 (FRI)

CUSTOMER CONTACT PETER BARQUIN / DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	1400	2200	8 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

PETE HOEFLICH, GARY ROUSH, DON GRIFFIN, ~~AND~~ PETER BARQUIN, AND MYSELF HELD A MEETING. PETE AND I GAVE U.S. SUGAR OUR RECOMMENDED RAPPING SEQUENCE MATRIX... AND TEST PLAN DATED 1/6/94. THE DAMPER OF THE EP WAS OBSERVED FOR A 0-100% RANGE AND IT RAN SMOOTHLY. THE ICOM LADDER LOGIC WAS ADDED TO THE PC AND COMMUNICATION TO THE PROCESSOR WAS ESTABLISHED. THE DUCT TRAVERSES WERE MADE AND THE VELOCITY PRESSURES WERE RECORDED FOR 30%, 40%, 50%, AND 60% ON THE DAMPER. THE PITOT TUBE: STD'RD TYPE, DWYER CAT #160-18

DELAYS

Process Problems: NONE

Testing Equipment Problems: NONE

THE FOLLOWING RAP SEQUENCE WAS ENTERED, PLACED IN AUTO, AND STARTED AT 2000 HRS: RAP AIR PRES = 20 PSIG

RAP INTERVAL = 8 MIN. RAP DURATION = 2 SEC

F1 CTR = 1 (every 64 min)
F2 CTR = 2 (every 128 min)
F3 CTR = 4 (every 256 min)
F4 CTR = 8 (every 512 min)
} 8 RAP STEPS D & C

NOTE: F2 DISCHARGE AND INLET SCRN RAP AT THE SAME TIME

COLD TEST AFTER INTERNAL INSPECTION:

F1: 27KV/11MA F2: 27/10 F3: 24/8 F4: 28/11

EP Problems: RED HOT ASH WAS OCCASIONALLY FALLING OUT OF THE ROTARY VALVE. THE ASH IN THE COLLECTION PAN WAS 1/2" THICK AND GLOWING RED. INVESTIGATING THE EP INTERNALS REVEALED NO WARPED PLATES AND NO FIRE. THE DUST ON THE F2/F3 WALKWAY AND F3/F4 WALKWAY WAS 1/2" THICK AND GLOWING RED IN SOME AREAS (MOST LIKELY DUE TO HIGH O_2 LEVEL WITH ACCESS DOORS OPEN). THE EP IS RUNNING AT 300°F EP INLET TEMP.

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1-8-94 (SAT)

CUSTOMER CONTACT PETER BARQUIN / DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1900	12
Lab Tech.				
Field Tech.				

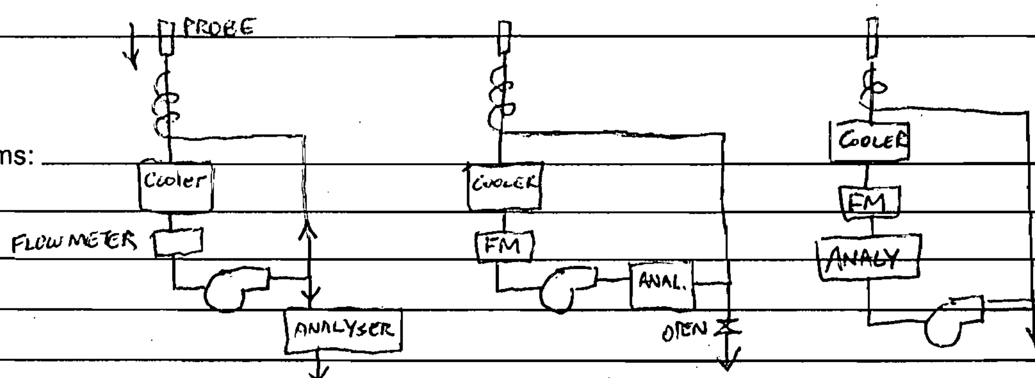
TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

AT APPROX 1600 HRS, FLD 2 SHORTED COMPLETELY. APPARENTLY F2C RAP CYLINDER DOES NOT STROKE AT 20 PSIG AND IS WEAK AT 25 PSIG. WE RAPID RAPPED F2 AND THE FIELD VOLTAGE WENT BACK TO NORMAL (>25KV). WE THEN PLACED THE RAPPING AIR AT 30 PSIG AND ALL RAP POSITIONS WORK FINE. (NOTE: IT TOOK FLD 2 APPROX 20 HRS TO BUILD UP AND SHORT OUT WHEN FLD 2 COL PLATES WEREN'T RAPPED AT PRESENT "AUTO" RAP SETTINGS).

DELAYS

Process Problems:



Testing Equipment Problems: THE O_2 EQUIPMENT CAME WITH NO SETUP/INSTALLATION INSTRUCTIONS. IT TOOK ALMOST ALL DAY TO SET UP BUT STILL APPEARED NOT TO WORK PROPERLY. WE ARE TO CALIBRATE THE ANALYSER WITH NITROGEN TO OBTAIN A "ZERO" BUT ONLY HAD CO_2 TEST GAS - NOT SURE OF % O_2 IN CO_2. THREE DIFFERENT SETUPS WERE TRIED BUT O_2 READINGS WERE QUESTIONABLE.

EP Problems: AT APPROX 1025 AM, POWER WAS LOST TO THE COMPUTER BUT NOT TO THE EP. AT APPROX 1600 HRS, WE REALIZED THAT EVER SINCE THE POWER LOSS WE COLLECTED NO HISTORICAL DATA. AFTER RE-BOOTING THE PC WE NO LONGER COMMUNICATED ~~WITH~~ FROM THE PC TO THE PROCESSOR. TROUBLESHOT PROBLEM FOR SEVERAL HOURS BUT COULDN'T RESOLVE PROBLEM.

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1-9-94 (SUN)

CUSTOMER CONTACT PETER BARQUIN / DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	2000	13 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

FIELD	MANUAL	AUTO
1	32KV/20MA	32KV/21MA
2	25 / 2	29 / 22
3	33 / 19	33 / 27
4	36 / 20	35 / 20

THE EP INLET STATIC PRESSURE WAS VERIFIED USING A MANOMETER. AFTER TUNING AVC. IT WAS NOTICED THAT 4 TIMES AS MUCH BUILDUP OUT OF SCREW AFTER CHANGING FROM A 6MIN RAP SEQ TO A 8 MIN RAP INTERVAL. AT A 2 SEC RAP DURATION, YOU GET AN IN-OUT-IN-OUT RAP.

DELAYS

AS LEFT: DAMPER SET AT 30% OPEN
DUCT PRESSURE: 9.4"W.C.
EP INLET TEMP: 253°F
EP OUT TEMP: 195°F
F1 V/I: 28.6KV / 10MA
F2 V/I: 27.7 / 7.6
F3 V/I: 29.1 / 21.1
F4 V/I: 31.5 / 21.5

Process Problems:

Testing Equipment Problems:

EP Problems: IOCNTRL error prevents real time data and trending from occurring on PC. Manually restarted the driver ABK to get the system to work. WHEN F2 COLLECTOR IS RAPPED MANUALLY FROM THE COMPUTER, IT DOES NOT STOP RAPPING. WHEN YOU GO BACK TO AUTO, THE COMPUTER SHOWS F2C RAPPING EVEN THOUGH IT ISN'T RAPPING.

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER: U.S. SUGAR CORP. DATE: 1-10-94 (MON)

CUSTOMER CONTACT: PETER BARQUIN / DON GRIFFIN JOB NO.: D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	0700	1930	12.5
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

TEST #1: 3000 ACFM, F1 F2 F3 POWER ON, F1 F2 RAP, M5 IN/OUT
TEST #3: 3000 ACFM, F1 POWER ON, NO RAPPING, M5 IN/OUT
AIR CONSULTING & ENGINEERING ARE PERFORMING THE PERFORMANCE TESTING.
THE OXYGEN ANALYSER WAS CALIBRATED AND INSTALLED TODAY AFTER TALKING TO THE VENDOR. ACE RAN A VELOCITY TRAVERSE AT THE EP INLET AND SAID WE ARE AT 2801 ACFM WHEN THE DAMPER IS 30% OPEN.

DELAYS

Process Problems: THE OXYGEN LEVEL TO THE EP WAS RECORDED AS 13%. THE OXYGEN LEVEL OUT OF THE EP WAS 15%.

Testing Equipment Problems: NONE

EP Problems: THE F2 COLLECTOR RAPPING CYLINDER DID NOT STROKE WHEN THE RAPPING WAS LOWERED TO 25 PSIG. THE SOLENOID VALVE WAS OILED AND RAPPING WORKED WELL AT 25 PSIG.

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1-11-94 (TUE)

CUSTOMER CONTACT PETER BARQUIN / DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	2100	14 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

TEST 8: 4500 ACFM, F1 F2 F3 F4 POWER ON, NO RAPPING, M5 IN/OUT
TEST 7: 4500 ACFM, F1 F2 F3 F4 POWER ON, F2 RAPPING & SOOT BLOW
TEST 9: 4500 ACFM, F1 F2 F3 F4 POWER ON, F1 F3 RAP, M5 IN/OUT
GARY GRIECO OF STONE AND WEBSTER ON-SITE. GRIECO HAS CONCERNS ABOUT 35% AIR IN-LEAKAGE TO EP. AT 935 HRS, THE SIDE BOX PURGE HOLES WERE CLOSED (TOP BOX ALREADY CLOSED). RAPPING REDUCED TO 1 SEC IN, 1 SEC OUT DURATION. GRIECO CREATED V-I CURVES FOR AVC RESPONSE

DELAYS

Process Problems:

Testing Equipment Problems:

EP Problems: IT WAS DETERMINED THAT THE OXYGEN ANALYSER PROBE WAS LEAKING IN AMBIENT AIR. TESTS #1, 3, 8, AND 7 OXYGEN READINGS ARE MOST LIKELY WRONG. THE PROBLEM WAS CORRECTED FOR TEST 9.

Form No.: ETDL 2/82

Litho in USA

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1-12-94 (WED)

CUSTOMER CONTACT PETER BARQUIN / DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1700	10 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

UMC decided to terminate the dry EP testing based on the 5 tests to date. Gary Grieco says the mobile was not correctly set up to collect baggasse ash for the following reasons: (1) The slow response of the SCR's can not react to the major sparks in Field 1 (2) F2 and F3 should only be used to plot the SCA curve (3) The temp drop accross the EP is too large (4) DUST IS BEING PULLED FROM THE F4 HOPPER & PLATES DUE TO NO OUTLET DISTRIB SCREEN IN PLACE (5) THE RAPPING WILL NOT WORK WITH THE LOW RESISTIVITY DUST.

DELAYS

Process Problems:

Testing Equipment Problems:

EP Problems: A MEETING WAS HELD WITH ED BRABHAM (UMC), DAVE LUTTENBERGER (UMC), MARK DEMECHKO (UMC), GARY ROUSH (UMC), MURRAY BRINSON (USS), PETER BARQUIN (USS), DON GRIFFIN (USS), AND GARY GRIECO (S&W). IT WAS DECIDED TO TERMINATE DRY EP TESTING AND PERFORM WEP TESTING. I TRAVELED BACK TO COLUMBUS TODAY.

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1-16-94 (SUN)

CUSTOMER CONTACT PETER BARQUIN/D.GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	1530	1730	2 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

MIST HEADER DESIGN: 3 NOZZLES & 2 PLUGS PER HEADER... 1 HEADER PER FIELD, 10 PSI MIN NEEDED FOR GOOD SPRAY PATTERN, AT 10 PSI → 12 GPM TOTAL FOR ALL FIELDS OR AT 5 PSI → 8.5 GPM TOTAL FOR ALL FIELDS, "SPRING SYSTEMS" NOZZLE # 1/8 K10. WASH HEADER DESIGN: 3 nozzles & 2 PLUGS PER HEADER, 1 HEADER PER FIELD, 10 PSI MIN NEEDED FOR GOOD SPRAY PATTERN, AT 40 PSI → 12 GPM PER FIELD, "BET" NOZZLE # MP125W. LANCE DESIGN: 1 NOZZLE SPRAYING DOWNSTREAM, AT 60 PSI → 6.42 GPM, "BET" # MP187W, 15 PSI MIN NEEDED FOR GOOD SPRAY PATTERN.

DELAYS

Process Problems:

Testing Equipment Problems:

EP Problems: ON-LINE IN MANUAL WITH DAMPER 40% OPEN AND THE MIST HEADERS OPTIMIZED TO 10 PSIG: F1 29KV/6MA F2 24KV/12.7MA F3 28KV/15MA F4 27KV/.11MA. NOTE WASH HEADERS OFF AND DUCT LANCE AT 40 PSI.

Form No.: ETDL 2/82 Litho in USA

United McGill Corporation

McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1/17/94 (MON)

CUSTOMER CONTACT PETER BARQUIN / D. GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1900	12 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

THE pH OF THE EP DISCHARGE WATER IS 7.0. WITH THE MIST HEADERS AT 8 PSIG AND THE DUCT LANCE AT 60 psig THE FOLLOWING VALUES WERE RECORDED:

LUMIGRAPH (MANUAL)				LUMIGRAPH (AUTO)	COMPUTER (AUTO)	
F1	32 KV	/8 MA	50% OUTPUT	26 KV / 5 MA	31.8% OUTPUT	2 MA SENSITIVITY
F2	32	/10	70% OUTPUT	33 / 11	40.8% "	8 MA "
F3	33	/12	50% OUTPUT	29 / 14	47.4% "	4 MA "
F4	33	/14	20% OUTPUT	29 / 16	27.4% "	9 MA "

NOTE: DAMPER AT 40% OPEN.

DELAYS

Process Problems: A bucket test was performed on the duct lance with the following results: AT 40 psig: 6.36 GPM. AT 60 psig: 7.25 GPM. THE DUCT LANCE FLOWMETER READS 6.4 GPM AT 60 PSIG.

Testing Equipment Problems:

EP Problems: FIELDS 2 AND 3 SHUT OFF OVERNIGHT DUE TO LOW VOLTS (MOST LIKELY FROM MOISTURE IN SIDE BOXES DUE TO RAIN). ALL SIDE BOX PURGE AIR HOLES ARE OPEN NOW AND WILL REMAIN OPEN FOR ALL WEP TESTING. THE FIELD 1 SPARK SENSITIVITY WAS SET AT 0.5 MA TO SEE A SPARK. AFTER INSTALLING THE MOV'S ACROSS THE T/R FEEDBACK, FIELD 1 DETECTED A 2 MA SPARK. A NEW TELMAR CURRENT TRANSMITTER WAS INSTALLED ON F1 TODAY.

Form No.: ETDL 2/82 Litho in USA

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1/18/94 (TUE)

CUSTOMER CONTACT P. BARQUIN / D. GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1900	12 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

COMPLETED WEP TEST 1: 4 FLDS ON AND 4869 ACFM (UNSATURATED)
COMPLETED WEP TEST 2: 3 FLDS ON AND 4600 ACFM (UNSATURATED)
COMPLETED WEP TEST 3: 2 FLDS ON AND 4231 ACFM (UNSATURATED)
GAVE SAVANNAH LABORATORIES P.O. # CP-94-0202-S TO ANALYSE WATER SAMPLES FOR CHLORIDE, HARDNESS, pH, DISSOLVED SOLIDS, AND SUSPENDED SOLIDS.

DELAYS

Process Problems:

Testing Equipment Problems: DURING WEP TEST #1, THE SILICA GEL IMPINGER AT THE EP INLET BECAME PLUGGED. THE EP INLET AND OUTLET TESTS WERE DELAYED 22 MINUTES TO RESOLVE THE PROBLEM.

EP Problems:

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1/19/94 (WED)

CUSTOMER CONTACT PETER BARQUIN/DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1800	11 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

ARTHUR E. LYALL, AN ENGINEER FOR THE STATE OF FLORIDA DEPT. OF ENVIRONMENTAL PROTECTION, WAS ON SITE. HE WITNESSED THE OPERATION OF THE WET EP.

COMPLETED WEP TEST 4: 4 FLDS ON AND 7077 ACFM (UNSATURATED)
COMPLETED WEP TEST 5: 2 FLDS ON AND 7261 ACFM (UNSATURATED)
COMPLETED WEP TEST 6: 3 FLDS ON AND 7694 ACFM (UNSATURATED)

DELAYS

Process Problems: RAN OUT OF CANE AT 700 HRS.

Testing Equipment Problems:

EP Problems: AT 1230 THE DUCT LANCE WATER VALVE WAS OPENED 100% IN ATTEMPT TO LOWER THE EP INLET TEMP. THE TEMP DECREASED BY ONLY 10°F (236 TO 226°F). AT 1300 HRS A TEE AND ADDITIONAL NOZZLE WERE INSTALLED IN THE DUCT LANCE. THE EP INLET TEMP DECREASED TO 187°F.

Form No.: ETDL 2/82 Litho in USA

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1/20/94 (THU)

CUSTOMER CONTACT PETER BARQUIN/DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1800	11 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

COMPLETED WEP TEST 7: 2 FLDS ON AND 7787 ACFM (UNSATURATED)
COMPLETED WEP TEST 8: 1 FLD ON AND 7637 ACFM (UNSATURATED)
COMPLETED WEP TEST 9: 2 FLDS ON, 7730 ACFM (UNSAT) WITH A SOOT BLOW
THE STACK IS MADE OUT OF 304L, THE SCRUBBER: 304L, AND THE FAN BLADES 316L. PETE HOEFLICH ARRIVED ON-SITE. A MEETING WAS HELD WITH THE FOLLOWING ATTENDEES: P. HOEFLICH, D. GRIFFIN, P. BARQUIN, M. BRINSON, AND MYSELF. THE FOLLOWING WAS REQUESTED BY U.S. SUGAR:

DELAYS

Process Problems: 1 REQUEST AN IMMEDIATE LETTER STATING THAT THE DRY EP DID NOT WORK 2 TWO SEPARATE REPORTS (LETTERS): ONE FOR THE DRY EP AND ONE FOR THE WET 3 QUOTE ON A FULL SCALE EP WITH A GUARANTEE 4 QUOTE ON A FULL SCALE EP LESS ONE FIELD AND NO GUARANTEE 5 QUOTE ON SLUDGE HANDLING SYSTEM.

Testing Equipment Problems:
WATER SAMPLES OF THE SCRUBBER #4 SUPPLY AND DISCHARGE WATER WERE TAKEN TODAY.

EP Problems:

Form No.: ETDL 2/82

Litho in USA

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1/21/94 (FRI)

CUSTOMER CONTACT PETER BARQUIN / DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1600	9 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

PRINT OUTS OF HISTORICAL TRENDING WERE MADE. THE EP WAS CLEANED OUT AND PREPARED TO SHIP. PETE HOEFLICH LEFT THE SITE.

DELAYS

Process Problems:

Testing Equipment Problems:

EP Problems:

Form No.: ETDL 2/82

Litho in USA

United McGill Corporation
McGill Precipitator Systems

Emission Testing Daily Log

CUSTOMER U.S. SUGAR CORP. DATE 1/22/94 (SAT)

CUSTOMER CONTACT PETER BARQUIN/DON GRIFFIN JOB NO. D-3029-9

UNITED McGILL PERSONNEL		TIME IN	TIME OUT	TOTAL
Engineer	MARK DEMECHKO	700	1000	3 HRS
Lab Tech.				
Field Tech.				

TESTS COMPLETED, WORK DONE

REMARKS (Questions/Special Instructions from/to UMC Customer or Consultant)

A BRIEF "WRAP UP" MEETING WAS HELD WITH DON GRIFFIN, GARY ROUSH, AND I. GARY AND I THEN LEFT THE SITE TO RETURN TO COLUMBUS.

DELAYS

Process Problems:

Testing Equipment Problems:

EP Problems:

United McGill Corporation 1779 Refugee Road, P.O. Box 820, Columbus, Ohio 43216-0820, 614/443-0192, Fax: 614/445-8759

FIELD SERVICE REPORT

Customer:	U.S. Sugar Corporation	**Date:**	12/30/93 - 1/22/94
Location:	Clewiston, FL	**Contact:**	Peter Barquin/Don Griffin
Application:	Bagasse Fired Boiler	**UMC Job No:**	D-3029-9
System:	Mobile No. 1	**Technician:**	Gerald Roush
Purpose:	Pilot Program		

12-30-93

I arrived at U.S. Sugar at 7 a.m. and met with Peter Barquin, company representative. The mobile had not arrived. The customer was installing the inlet ductwork for the mobile. I informed Peter the center line elevation of the inlet ductwork was 7ft.6in. The mobile arrived at 5pm.The driver was delayed in Kentucky due to severe weather conditions. He also had a flat tire in route to U.S. Sugar. I left the plant at 6 p.m.

12-31-93

I spent the day setting up the mobile EP. I installed the rapping cylinders and unpinned the EP fields. I also setup the computer system and data highway cable.

1-3-94

I completed setting up the mobile, and installing the ductwork. At 1 p.m. I started up the mobile. The boiler load was 280 kpph steam. After warm-up, the EP fields were in manual. I reported field voltage and current to Columbus. The EP fan damper was at 70% open, the EP inlet temperature was 335°F, the EP outlet temperature was 275°F. The mobile was online for 4 hours. Opacity was 5% or less.During the 4 hour run, boiler no.4 had a fuel gap, at which time I observed an increase in opacity up to 10%. In field no.1 the a-side top structure baffle plate clip had broken off. U.S. Sugar installed a new clip.

1-4-94

I received the computer key today. EP fields were in manual mode. Boiler load was 294 kpph. The opacity was 5% or less. EP inlet temperature was 335°F, The EP outlet temperature was 275°F. The EP flow was approximately 6400 ACFM. I met with the owner of the stack testing company, (Air Consulting & Engineering, Inc.) Mr. Steven L. Neck, P.E. We ran a few velocity checks and reduced the EP flow to approximately 4500 ACFM. Mr. Barquin of U.S. Sugar had us run a white towel test twice over the EP outlet stack. It did get the towel dirty but I informed Peter that the particulate testing would determine if in compliance.

1-5-94

I wrote a procedure for the mobile EP to give U.S. Sugar shift electricians a guideline of what to do if the EP fields shut off during night time operation. This procedure will be taped to the control panel of the mobile EP. I ran the mobile in manual mode. The boiler load was 287 kpph. Flow was approximately 4500 ACFM. EP inlet temperature was 300°F. EP outlet temperature was 240° F. I worked on tuning the field AVC controls and optimizing the EP rapping sequence. During todays operation U.S. Sugar performed a soot-blow. During the soot-blow I observed an increase in EP outlet opacity up to 10%. The field voltages maintained their respective values.

1-6-94

The mobile ran all night at approximately 4500 ACfM. I received the O_2 monitor today. The rapping air pressure was reduced to 20 psi. Rap duration was 2 minutes, rap interval was 8 minutes. I also observed that both rotary valves have in-leakage, the A-side rotary valve leaks a lot more than the B-side valve. At approximately 9:30 A.M. I turned the EP rapping off. It was off for 4 hours to load up the EP fields. At 1:30 P.M. I observed glowing red ambers in the EP catch pans. I immediately aborted the mobile EP. I turned the EP fields off and performed a rapid-rap on all 4 EP fields. After aborting the system I did an internal inspection of the mobile. Here are my observations: Field no. 1 leading edge of collector plates had up to 1/4 inch of dust build up. Field no. 1 leading edge of discharge plates and needle strips had up to 1/16 to 1/8 inch of dust build up. Field no.1 trailing edge of collector plates had up to 1/4 inch of dust build up. Field no. 1 trailing edge of discharge plates had up to 1/8 dust build up. Field no. 2 leading edge of collector plates had up to 1/4 inch dust build up. Field no. 2 leading edge of discharge plates and needle strips had up to 1/8 inch dust build up. Field no. 2 trailing edge of collector plates had up to 1/8 inch dust build up. Field no. 2 trailing edge of discharge plates and needle strips had up to 1/8 inch dust build up. Field no. 3 leading edge of collector plates had up to 1/8 inch dust buildup. Field no. 3 leading edge of discharge plates and needle strips had up to 1/16 inch dust build up. Field no. 3 trailing edge of collector discharge plates and needle strips had up to 1/16 inch dust build up. All of field no. 4 had a light dust coating up to 1/16 inch.

1-7-94

The mobile EP ran all night. Mark Demechko and Pete Hoeflich of UMC arrived on site today. We had a meeting with Peter Barquin, and Don Griffin of U.S. Sugar. In the afternoon Mark and I ran velocity traverses. At 4:43 pm I ran a cold test, here are the results: Field no. 1: 27 kv and 11 ma. Field no. 2: 27 kv and 10 ma. Field no. 3: 24 kv and 8 ma. Field no. 4: 28 kv and 11 ma. After the cold test we put the EP back on-line and worked on AVC tuning and rapping optimization.

1-8-94

The mobile ran all night without any major problems. Mark and I worked on setting up the O_2 analyzer, AVC tuning, and rapping optimization. NOTE: The directions for setting up the O_2 analyzer were very confusing and the equipment was not properley labeled.

1-9-94

Mark and I continued working on setting up the O_2 analyzer and on AVC tuning. The analyzer itself was recieved not in working order, so we repaired it. It had a broken tube inside it. On Monday, 1-10-94 I notified the supplier of this.

1-10-94

We performed two inlet/outlet tests today. Mark monitored the mobile and I monitored the boiler control room as well as observed opacity at the outlet stack. I also took dust samples and baseline pictures of the opacity.

1-11-94

See Mark D. of UMC daily log for today.

1-12-94

See Mark D. of UMC daily log for today.

1-13-94

Mark D. of UMC left for Columbus yesterday. With the dry test results it was determined that a dry UMC EP would be too large to be affordable. I spent the day starting to convert the mobile EP to a wet EP. I also made arrangements with Goodyear of Clewiston,Fl. to look at the flat mobile EP tire. I coordinated with U.S. Sugar where to install the inlet duct spray lance and the new inlet duct test ports. I replaced the Field no.2 lumigraph cathode, and re-installed part of the EP outlet demister. I also started to repair the A-side rotary valve drive taper lock.

1-14-94

I performed the following tasks: Installed the WEP water supply/fresh water. Installed the rest of the outlet demister. Recieved the UMC shipment of hoses at 3 pm. Peter Barquin of U.S. Sugar called the following WEP customers of UMC: Collins Pine - Chester,Ca. - Jim Stewart. Proctor & Gamble - Albany,Ga. - Manfred Riley. Weyerhauser - Elkin,Nc. - John Hansen. Checked on the status of the Mobile EP spare tire being repaired. Received new WEP test program. Purchased new 18 inch and 24 inch pipe wrenches per Mark D. of UMC.

1-15-94

Ran water piping for the WEP mist/wash headers. Cleaned all mist/wash spray nozzles. Installed inlet duct spray lance and water hose to it. Completed repairing the A-side rotary valve chain drive. U.S. Sugar fabricated a wooden trough to evacuate the WEP water discharge to their pond system.

1-16-94

Completed setting the WEP up for wet operation. Mark D. of UMC arrived on site today and worked on correcting AVC tuning problems.

1-17-94

Packed up the rental O_2 analzer and shipped it. Installed an inlet duct spray lance flow meter. Ran a white towel test (results were good). Obtained WEP discharge water samples (pH was 7.0) Installed mov's on the T/R sets. Replaced field no. 1 bad Telmar current transmitter. Had U.S.Sugar remove field no. 1 hopper wash down piping. The piping was warped and was causing close clearance to the field no. 1 discharge plates.

1-18-94

Received the WEP field flow control valve today. We performed 3 inlet/outlet tests today.

1-19-94

Performed 3 inlet/outlet tests today. Reworked the inlet duct spray lance: one nozzle facing upstream and one facing downstream. Nozzles are both BETE MP 187.

1-20-94

Performed 3 inlet/outlet tests today. Pete Hoeflich of UMC arrived today. U.S. Sugar started repairing our ductwork crate today.

1-21-94

Ran an inlet particle size test today. Packed up the mobile EP for shipment. Packed up the Dell computer system and left it in U.S. Sugar shipping deptartment for shipping Monday, 1/24.

1-22-94

Mark Demechko and I stopped in at the customer site this morning to meet with Mr. Don Griffin of U.S. Sugar. Don was very positive about the tests and the UMC equipment. We thanked Don for all the cooperation and help we received from U.S. Sugar which in turn enabled UMC to have a succesful test program. Mark and I then traveled home to Columbus.

GR:sap
SUGAR

c: G. Roush
M. Demechko/Original

APPENDIX 2

EP and Water System Log Sheets

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: DRY EP TEST 1 Date: 1/10/94

Unit No.: BOILER #4 (START TIME: 1215) (STOP TIME: 1320)

LOCATION	Time	1215	1225	1235	1245	1255	1300	1305	1315
C.R.	AIR FLOW OUT (GREEN PEN)	914	914	914	914	914	914	914	
C.R.	STEAM OUT TEMP (BLUE PEN)	800	800	800	800	800	800	800	
C.R.	Steam rate OUT (RED PEN)	280	294	294	280	280	273	273	
C.R.	Steam OUT Pressure	685	685	685	635	640	635	635	
C.R	SIX BOILER STEAM OUTLET LOADING	771600	773700	774300	77320	77600	77860	77780	
C.R.	FEEDER SPEED (RPM) 1 2 3	10 10 11	10 10 11	10 10 11	10 10 11	10 10 11	10 10 10	11 10 11	
C.R.	FEEDER SPEED (RPM) 4 5 6	12 11 8	12 12 8	12 12 8	12 12 8	12 11 8	12 11 8	12 11 8	
E.P.	DUCT PRESSURE (EP IN)	9.67	9.91	9.63	9.41	9.53	9.59	9.56	9.63
E.P.	EP Inlet Temp Deg F	259°F	257	259	260	260	261	261	261
E.P.	EP Outlet Temp Deg F	200°F	202	205	205	207	207	208	207
E.P.	% Oxygen Boiler/EP								
E.P.	FAN DAMPER POSITION	30%	30%	30%	30%	30%	30%	30%	30%
E.P.	FAN AMPS	24	24	24	24	24	24	24	24
E.P.	Field 1 kV/mA	31.4/15	33.3/15	33.5/14	34/16	32/12	33/14	33/14	34/16
E.P.	Field 2 kV/mA	28.9/15	29.2/14	29.4/14	27/10	26/8	26/8	27/9	27/10
E.P.	Field 3 kV/mA	24.2/12	25/12	26/14	24/11	24/11	25/12	24/11	25/11
E.P.	Field 4 kV/mA								
E.P.	Field 1 Rap Time		F1D 1228	F1C 1236					
E.P.	Field 2 Rap Time				F2D 1244	F2C 1252			
E.P.	Field 3 Rap Time								
EP	Field 4 Rap Time								
E.P.	EP OPACITY	NO RAP <5%	F1D RAP 10%	F1C RAP 10%	F2D RAP 10%	F2C RAP 10%			
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	RAPPING AIR PRESSURE	30 PSIG	30	30	30	30			
E.P.	PHOTOS TAKEN	1225	1228	1236	1244	1252			

NOTES: At 1212, F4 was shut off and F3/F4 rapping was disabled. CONVEYOR NOT RUNNING. IT IS OVERCAST WITH LIGHT RAIN. 15% oxygen out of EP per AIR CONSULTING. One rotary valve open and one closed off. At 1322, F4 was turned on and F3/F4 rapping enabled. Vibrators on 20 sec off 10 min

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: DRY EP TEST 3 Date: 1/10/94

Unit No.: BOILER #4 START TIME: 1534 STOP TIME: 1637

LOCATION	Time	1530	1534	1544	1554	1604	1614	1624	1634
C.R.	AIR FLOW OUT (GREEN PEN)	914	X	914	914	914	X	912	914
C.R.	STEAM OUT TEMP (BLUE PEN)	800	X	800	800	800	X	800	800
C.R.	Steam rate OUT (RED PEN)	280	X	294	290	287	X	273	285
C.R.	Steam OUT Pressure	620	X	635	648	640	X	580	620
C.R	SIX BOILER STEAM OUTLET LOADING	857500	X	846300	86900	860700	X	851200	860500
C.R.	FEEDER SPEED (RPM) 1 2 3	12 10 10	X	12 10 11	12 10 11	12 16 11	X	12 10 11	12 10 11
C.R.	FEEDER SPEED (RPM) 4 5 6	12 10 8	X	12 10 8	12 11 8	12 10 7	X	11 11 7	12 11 7
E.P.	DUCT PRESSURE (RPM) (EP IN)	10.0"	9.71	9.77	9.66	9.63	9.76	9.73	10.00
E.P.	EP Inlet Temp Deg F	295°F	296	295	294	295	292	293	289
E.P.	EP Outlet Temp Deg F	231°F	232	232	232	232	231	231	229
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	X
E.P.	FAN DAMPER POSITION	30%	30%	30%	30%	30%	30%	30%	30%
E.P.	FAN AMPS	24	24	24	24	24	24	24	24
E.P.	Field 1 kV/mA	27/3	28/4	29/5	31/5	31/6	32/7	32/9	32/12
E.P.	Field 2 kV/mA	26/6	X	X	X	X	X	X	X
E.P.	Field 3 kV/mA	22/9	X	X	X	X	X	X	X
E.P.	Field 4 kV/mA	30/19	X	X	X	X	X	X	X
E.P.	Field 1 Rap Time	X	X	X	X	X	X	X	X
E.P.	Field 2 Rap Time	X	X	X	X	X	X	X	X
E.P.	Field 3 Rap Time	X	X	X	X	X	X	X	X
EP	Field 4 Rap Time	X	X	X	X	X	X	X	X
E.P.	EP OPACITY								
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	RAPPING AIR PRESSURE	25 PSIG	BUT	NO	RAPPING	TAKING	PLACE		
E.P.	PHOTOS TAKEN				1557				

NOTE: BAD BAGGASSE AT 1625. STEAM LOAD WENT FROM 290,000 TO 260,000. LOADS SWINGS TO APPROX 255,000.

NOTES: At 1531, F2, F3, and F4 were shut OFF... Rapping to F1, F2, F3, F4 was disabled. OVERCAST WITH LIGHT RAIN. SCREW CONVEYOR IS OFF. One rotary valve blocked off and one open. The vibrators are on 20 sec, off 10 min.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: DRY EP TEST 7 Date: 1/11/94

Unit No.: BOILER #4 START TIME 1300 STOP TIME 1403

LOCATION	Time	1300	1310	1320	1330	1340	1350	1400	
C.R.	AIR FLOW OUT (GREEN PEN)	914	914	X	914	914	914	X	
C.R.	STEAM OUT TEMP (BLUE PEN)	800	800	X	804	807	807	X	
C.R.	Steam rate OUT (RED PEN)	287	275	X	280	290	280	X	
C.R.	Steam OUT Pressure	640	620	X	650	660	660	X	
C.R	SIX BOILER STEAM OUTLET LOADING	86500	857600	X	876300	885400	884000	X	
C.R.	FEEDER SPEED (RPM) 1 2 3	11 10 11	12 10 12	X	12 10 12	11 10 12	12 10 12	X	
C.R.	FEEDER SPEED (RPM) 4 5 6	11 9 8	11 9 12	X	12 10 8	11 10 9	12 10 9	X	
E.P.	DUCT PRESSURE (EP IN)	9.87"	9.99"	9.98"	10" MAX	10" MAX	10" MAX	9.96	
E.P.	EP Inlet Temp Deg F	337°F	337	327	336	336	337	336	
E.P.	EP Outlet Temp Deg F	290°F	285	286	286	284	285	287	
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	
E.P.	FAN DAMPER POSITION	49%	49%	49%	49%	49%	49%	49%	
E.P.	FAN AMPS	24A	24A	24A	24A	24A	24A	24A	
E.P.	Field 1 kV/mA	32/0	32/0	26/0	25/0	25/0	29/0	33/0	
E.P.	Field 2 kV/mA	34/22	34/21	34/22	33/23	33/23	34/22	33/21	
E.P.	Field 3 kV/mA	34/39	34/38	34/39	33/39	33/39	31/36	23/10	
E.P.	Field 4 kV/mA	31/21	31/21	31/21	31/21	30/23	31/22	30/23	
E.P.	Field 1 Rap Time	X	X	X	X	X	X	X	
E.P.	Field 2 Rap Time	X	F2C 1305	F2D 1318	X	X	X	X	
E.P.	Field 3 Rap Time	X	X	X	X	X	X	X	
EP	Field 4 Rap Time	X	X	X	X	X	X	X	
E.P.	EP OPACITY		15%	15%		5%	5%		
C.R.	Grate Rake								
C.R.	Soot Blower				1329 START			1348 STOP	
E.P.	RAPPING AIR PRESSURE		29 PSIG	29 PSIG					
E.P.	PHOTOS TAKEN	BASELINE 1304	1305	1313					

NOTES: RAPPING TOOK PLACE MANUALLY WITH "IN" FOR 1 SEC ; "OUT" FOR 1 SEC. FIMA TRANSMITTER IS BAD. CONVEYOR OFF. BOTH ROTARY VALVES CLOSED. VIBRATORS OFF. Cloudy and Grey outside.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: DRY EP TEST 8 Date: 1/11/94

Unit No.: BOILER #4 START TIME 958 STOP TIME: 1101

LOCATION	Time	1000	1010	1020	1030	1040	1050	1100	
C.R.	AIR FLOW OUT (GREEN PEN)	914	914	914	912	914	914		
C.R.	STEAM OUT TEMP (BLUE PEN)	800	800	800	800	800	800		
C.R.	Steam rate OUT (RED PEN)	273	287	300	283	287	287		
C.R.	Steam OUT Pressure	632	640	650	660	630	680		
C.R.	SIX BOILER STEAM OUTLET LOADING	862600	868600	854900	857500	871400	871800		
C.R.	FEEDER SPEED (RPM) 1 2 3	11 10 8	10 10 9	10 10 9	10 10 9	10 10 8	11 10 9		
C.R.	FEEDER SPEED 4 5 6	12 11 8	12 11 8	12 11 9	12 11 8	12 11 9	11 11 8		
E.P.	DUCT PRESSURE (EP IN)	10.00"	10" MAX	10" MAX	10" MAX	10" MAX	MAX	MAX	
E.P.	EP Inlet Temp Deg F	332°	334°	335°F	336°	336°	336°	332°	
E.P.	EP Outlet Temp Deg F	276°	279°	277°	279°	278°	278°	277°	
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	
E.P.	FAN DAMPER POSITION	49%	49%	49%	49%	49%	49%	49%	
E.P.	FAN AMPS	24A	24A	24A	24A	24A	24A	24A	
E.P.	Field 1 kV/mA	29/4.6	30.1/7.3	30.2/6.8	30/5.9	29/6	30/7.4	31/6.1	
E.P.	Field 2 kV/mA	33/25	32.8/24	33/26.1	33/25	32/26	33/26	32/24.5	
E.P.	Field 3 kV/mA	33/42	32.3/41	32/38.6	31/35	31/40	32/39	31.5/34	
E.P.	Field 4 kV/mA	30/21	29.2/21.1	29/21.5	30/21.7	30/25	30/25	31/24	
E.P.	Field 1 Rap Time	X	X	X	X	X	X	X	
E.P.	Field 2 Rap Time	X	X	X	X	X	X	X	
E.P.	Field 3 Rap Time	X	X	X	X	X	X	X	
EP	Field 4 Rap Time	X	X	X	X	X	X	X	
E.P.	EP OPACITY	BASE	LINE	<5%					
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	RAPPING AIR PRESSURE	25 PSIG	BUT NO	RAPPIN	G IN T	EST			
E.P.	PHOTOS TAKEN			1001	1005				

NOTE: ONE BOILER SPIKE FROM 308,000 TO 283,000. ANOTHER SPIKE FROM 298,000 TO 280,000. 35 CARS OF BAGGASSE. AT 4760 ACFM. WITH SCREW CONVEYORS NOT RUNNING WE HAVE 5% OR LESS OPACITY. WITH SCREW CONVEYORS RUNNING THE OPACITY IS 15 TO 20%

NOTES: At 935, the side box purge holes were closed off 100%. CONVEYOR NOT RUNNING. Both rotary valves are closed. The top box purge holes are closed and have been closed since first test. The vibrators are off. Cloudy with some blue sky

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: DRY EP TEST 9 Date: 1/11/94

Unit No.: BOILER #4

(START TIME 1550) (STOP TIME 1651)

LOCATION	Time	1550	1600	1610	1620	1630	1640	1650	
C.R.	AIR FLOW OUT (GREEN PEN)	800	800	800	X	800	800	800	
C.R.	STEAM OUT TEMP (BLUE PEN)	914	914	914	X	914	914	914	
C.R.	Steam rate OUT (RED PEN)	280	286	273	X	280	280	298	
C.R.	Steam OUT Pressure	620	590	640	X	640	640	640	
C.R	SIX BOILER STEAM OUTLET LOADING	857600	840000	850K	X	885700	879500	924800	
C.R.	FEEDER SPEED (RPM) 1 2 3	12 11 12	10 11 10	10 11 11	X	11 10 12	12 10 12	11 10 12	
C.R.	FEEDER SPEED (RPM) 4 5 6	11 12 9	12 12 9	11 11 8	X	11 11 8	12 11 9	12 11 8	
E.P.	DUCT PRESSURE (EP IN)	9.78"	10" MAX	9.83	10" MAX	9.95	9.86	10" MAX	
E.P.	EP Inlet Temp Deg F	336°F	337	338	339	338	337	337	
E.P.	EP Outlet Temp Deg F	278°F	280	279	282	282	283	282	
E.P.	% Oxygen Boiler/EP	8.3%	8.4%	8.5%	8.2%	8.3%	8.2%	7.9%	
E.P.	FAN DAMPER POSITION	49%	49%	49%	49%	49%	49%	49%	
E.P.	FAN AMPS	24A	24A	24A	24A	24A	24A	24A	
E.P.	Field 1 kV/mA	34/14	34/16	33/18	34/18	32/16	28/10	30/18	
E.P.	Field 2 kV/mA	34/19	34.3/20	35/19	34/18	34/19	34/20	34/18	
E.P.	Field 3 kV/mA	28/18	34/38	26/12	31/23	31/24	30/19	31/25	
E.P.	Field 4 kV/mA	32/19	32/18	32/19	31/19	31/19	31/20	31/19	
E.P.	Field 1 Rap Time	X	X	F1C 1611	F1D 1621	X	X	X	
E.P.	Field 2 Rap Time	X	X	X	X	X	X	X	
E.P.	Field 3 Rap Time	X	X	X	X	F3C 1628	F3D 1637	X	
EP	Field 4 Rap Time	X	X	X	X	X	X	X	
E.P.	EP OPACITY			F1C 25%	F1D 15%	F3C 40%	F3D 25%		
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	RAPPING AIR PRESSURE		30 PSIG						
E.P.	PHOTOS TAKEN								

NOTES: RAPPING TOOK PLACE MANUALLY FOR 1 SEC "IN" STROKE AND 1 SEC "OUT". CLOUDY WITH LIGHT RAIN. VIBRATORS OFF. BOTH ROTARY VALVES ARE BLANKED OFF. SCREW NOT RUNNING. BOILER SWING AT 1600 FROM 280,000 TO 255,000. BOILER SWING AT 1630 FROM 280,000 TO 266,000.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 1

Date: 1-18-94

Unit No.: BOILER #4

START TIME 1009 STOP TIME 1135

LOCATION	Time	1010	1020	1035	1045	1055	1105	1120	1130
C.R.	AIR FLOW OUT (GREEN PEN)	910	914	914	X	914	914	914	914
C.R.	STEAM OUT TEMP (BLUE PEN)	793	740	780	X	800	780	780	780
C.R.	Steam rate OUT (RED PEN)	287	280	280	X	294	287	287	294
C.R.	Steam OUT Pressure	620	618	618	X	620	615	635	625
C.R	SIX BOILER STEAM OUTLET LOADING	878500	879200	873100	X	872300	864300	850900	870300
C.R.	FEEDER SPEED 1 2 3	13 10 15	13 10 16	13 10 16	X	13 10 15	13 11 15	13 11 15	13 10 15
C.R.	FEEDER SPEED 4 5 6	12 10 9	13 11 9	12 11 9	X	12 11 9	12 11 10	13 11 9	12 11 10
E.P.	DUCT PRESSURE (EP IN)	10" MAX	9.98	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX
E.P.	EP Inlet Temp Deg F	195°F	200	193°F	189	194	192	194	200
E.P.	EP Outlet Temp Deg F	139°F	142	139	139	139	134	138	139
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	X
E.P.	FAN DAMPER POSITION	41%	41%	41%	41	41	41	41	41
E.P.	FAN AMPS	25A	25A	25A	25	25	25	25	25
E.P.	Field 1 kV/mA (AUTO)	24/4	26/5	27/5	26/4	27/5	24/4	27/5	25/5
E.P.	Field 2 kV/mA (AUTO)	32/11	32/12	32/12	32/11	31/11	32/12	32/12	33/12
E.P.	Field 3 kV/mA (AUTO)	29/17	25/10	26/11	26/12	27/12	28/14	25/11	26/12
E.P.	Field 4 kV/mA (AUTO)	28/14	28/11	27/15	28/15	27/16	28/15	27/16	28/15
E.P.	Field 1 MIST PRESSURE	8 PSI	8	8	8	8	8	8	8
E.P.	Field 2 MIST PRESSURE	8 PSI	8	8	8	8	8	8	8
E.P.	Field 3 MIST PRESSURE	8 PSI	8	8	8	8	8	8	8
EP	Field 4 MIST PRESSURE	8 PSI	8	8	8	8	8	8	8
E.P.	EP OPACITY	<5%							
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60PSI/6.4	60/6.4	60/6.4	60/6.4	60/6.4	60/6.4	60/6.2	60/6.2
E.P.	PHOTOS TAKEN				1113	1113			

NOTES: AT 1121 TO 1123 THE HOSE TO THE DUCT LANCE BECAME DISCONNECTED. BAGASSE WAS GOOD THROUGHOUT TEST. TOOK EP IN AND EP OUTLET WATER SAMPLES AT 1015.

NOTES: AT 1018 THE INLET TEST PROBE WAS PULLED DUE TO AN UNKNOWN RESTRICTION IN THE LINE. THE SILICA GEL IMPINGER WAS PLUGGED. NOTE: THE OUTLET TESTING WAS STOPPED AT 1018. AT 1040 THE INLET & OUTLET TESTING RESUMED. OVERCAST WITH LIGHT RAIN.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 2 Date: 1-18-94

Unit No.: BOILER #4

START TIME 1325 STOP TIME 1427

LOCATION	Time	1327	1337	1347	1357	1407	1417	1427	
C.R.	AIR FLOW OUT (GREEN PEN)	914°F	914	X	914	914	914	X	
C.R.	STEAM OUT TEMP (BLUE PEN)	780°F	780	X	780	780	780	X	
C.R.	(K lb/Hr) Steam rate OUT (RED PEN)	287	252	X	263	280	287	X	
C.R.	Steam OUT Pressure (psi)	610	580	X	580	600	570	X	
C.R	SIX BOILER STEAM OUTLET LOADING (lb/Hr)	859100	865900	X	851900	844900	845400	X	
C.R.	FEEDER SPEED 1 2 3 RPM	13 10 15	13 11 12	X	13 10 13	13 10 12	13 10 12	X	
C.R.	FEEDER SPEED 4 5 6 RPM	12 10 9	12 11 9	X	12 11 9	12 11 10	13 11 9	X	
E.P.	DUCT PRESSURE (EP IN)	10" MAX	9.81"	9.89"	9.72	10 MAX	9.76"	10 MAX	
E.P.	EP Inlet Temp Deg F	198°F	201°F	198°	198	195	192	179	
E.P.	EP Outlet Temp Deg F	141°F	143°F	142	143	139	137	133	
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	
E.P.	FAN DAMPER POSITION	39%	39%	39%	39%	39%	39%	39%	
E.P.	FAN AMPS	24 A	24	24	24	24	24	24	
E.P.	Field 1 kV/mA (AUTO)	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 2 kV/mA (AUTO)	33KV/11MA	32/12	32/11	33/11	33/12	32/12	33/11	
E.P.	Field 3 kV/mA (AUTO)	30/19	27/14	31/22	31/22	31/22	30/23	30/23	
E.P.	Field 4 kV/mA (AUTO)	29/12	25/14	29/12	27/12	28/12	28/12	28/15	
E.P.	Field 1 MIST PRESSURE	8 PSI	8	8	8	8	8	8	
E.P.	Field 2 MIST PRESSURE	8	8	8	8	8	8	8	
E.P.	Field 3 MIST PRESSURE	8	8	8	8	8	8	8	
EP	Field 4 MIST PRESSURE	8	8	8	8	8	8	8	
E.P.	EP OPACITY								
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60PSI/6.4	60/6.4	60/6.4	60/6.4	60/6.4	60/6.4	60/6.4	
E.P.	PHOTOS TAKEN				1351				

GPM

NOTES: LOST ONE FEEDER AND DROPPED LOADING FROM 280 TO 252 AT 1340. GOOD BAGASSE. LOAD SWING AT 1400 HRS FROM 280 TO 245 KPH.

NOTES: OVERCAST WITH NO RAIN.

TOOK EP DISCHARGE SAMPLE AT 1335. AT 1342, F3 SHUT OFF ON LOW VOLTS... STARTED BACK UP AND RAN IT IN MANUAL.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 3 Date: 1-18-94

Unit No.: BOILER #4 START TEST 1558 STOP TEST 1700

LOCATION	Time	1600	1610	1620	1630	1640	1650	1657	
C.R.	AIR FLOW OUT (GREEN PEN)	900°F	914	914	X	914	914		
C.R.	STEAM OUT TEMP (BLUE PEN)	790°F	800	780	X	790	783		
C.R.	Steam rate OUT (RED PEN)	287 Klb/hr	294	287	X	283	285		
C.R.	Steam OUT Pressure	600	610	600	X	600	615		
C.R	SIX BOILER STEAM OUTLET LOADING	859000 lb/hr	850100	833400	X	883300	888700		
C.R.	FEEDER SPEED RPM 1 2 3	13 10 12	13 10 12	13 10 12	X	13 10 11	13 10 11		
C.R.	FEEDER SPEED RPM 4 5 6	12 11 9	12 11 9	12 11 9	X	13 11 9	13 10 9		
E.P.	DUCT PRESSURE (EP IN)	10" MAX	10" MAX	10 MAX	10 MAX	10 MAX	10 MAX		
E.P.	EP Inlet Temp Deg F	203°F	200	200	199	197	195		
E.P.	EP Outlet Temp Deg F	140°F	138	138	138	139	134		
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X		
E.P.	FAN DAMPER POSITION	37%	37%	37%	37%	37%	37%		
E.P.	FAN AMPS	24 A	24 A	24 A	24 A	24 A	24 A		
E.P.	Field 1 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF		
E.P.	Field 2 kV/mA (AUTO)	33/11	33/11	33/11	32/9	33/11	33/11		
E.P.	Field 3 kV/mA (MANUAL)	32/27	33/27	32/27	33/26	33/26	33/26		
E.P.	Field 4 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF		
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	Field 2 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	Field 3 MIST PRESSURE	8 PSIG	8	8	8	8	8		
EP	Field 4 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	EP OPACITY								
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60/6.2 GPM	60/6.2	60/6.2	60/6.2	60/6.4	60/6.4		
E.P.	PHOTOS TAKEN		1616						

NOTES: CLOUDY, NO RAIN.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 4 Date: 1/19/94

Unit No.: BOILER #4 START TIME 1116 STOP TIME 1217

LOCATION	Time	1117	1125	1155	1201	1210	1215		
C.R.	AIR FLOW OUT (GREEN PEN)	914°F	914	914	914	X	914		
C.R.	STEAM OUT TEMP (BLUE PEN)	780°F	786	800	800	X	800		
C.R.	Steam rate OUT (RED PEN)	238 klb/hr	266	280	280	X	294		
C.R.	Steam OUT Pressure	555 psi	620	635	660	X	660		
C.R.	SIX BOILER STEAM OUTLET LOADING	807500 lb/hr	833900	842100	846800	X	873400		
C.R.	FEEDER SPEED RPM 1 2 3	11 10 10	11 10 10	12 11 10	12 11 10	X	11 10 10		
C.R.	FEEDER SPEED RPM 4 5 6	11 10 8	11 12 8	11 11 8	11 12 8	X	11 11 8		
E.P.	DUCT PRESSURE (EP IN)	10" MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX		
E.P.	EP Inlet Temp Deg F	223°F	224	231	229	227	226		
E.P.	EP Outlet Temp Deg F	151°F	150	153	155	155	156		
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X		
E.P.	FAN DAMPER POSITION	88%	88%	88%	88%	88%	88%		
E.P.	FAN AMPS	30A	30A	30A	30A	30A	30A		
E.P.	Field 1 kV/mA (AUTO)	25KV/4	25/7	24/5	25/5	26/4	28/6		
E.P.	Field 2 kV/mA (AUTO)	33/12	34/12	34/13	34/10	34/10	34/11		
E.P.	Field 3 kV/mA (AUTO)	25/11	25/11	26/12	25/11	25/13	23/16		
E.P.	Field 4 kV/mA (AUTO)	29/15	28/10	28/15	28/11	29/12	29/14		
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	Field 2 MIST PRESSURE	8	8	8	8	8	8		
E.P.	Field 3 MIST PRESSURE	8	8	8	8	8	8		
EP	Field 4 MIST PRESSURE	8	8	8	8	8	8		
E.P.	EP OPACITY	5%							
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60 PSIG 6.4 GPM	60/6.4	60/6.4	60/6.4	60/6.4	60/6.4		
E.P.	PHOTOS TAKEN		1125						

NOTES: CLOUDY AND VERY WINDY... CANNOT PERFORM A METHOD 9.
1130 HRS: WATER SAMPLE. BAGGASSE IS WET TODAY.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 5 Date: 1/19/94

Unit No.: BOILER #4

TEST START 1351 TEST STOP 1454

LOCATION	Time	1353	1410	1420	1430	1440	1450	/	
C.R.	AIR FLOW OUT (GREEN PEN)	914°F	914	914	914	914	914		
C.R.	STEAM OUT TEMP (BLUE PEN)	800°F	800	800	800	800	800		
C.R.	Steam rate OUT (RED PEN)	280 Klb/hr	280	280	280	280	280		
C.R.	Steam OUT Pressure	660 psi	640	610	610	600	615		
C.R	SIX BOILER STEAM OUTLET LOADING	896700 lb/hr	880500	870000	879200	882000	886200		
C.R.	FEEDER SPEED RPM 1 2 3	12 11 11	12 11 10	12 11 11	12 11 10	11 12 11	13 10 14		
C.R.	FEEDER SPEED 4 5 6	11 12 8	11 12 7	11 12 8	12 12 8	11 12 8	11 11 8		
E.P.	DUCT PRESSURE (EP IN)	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX		
E.P.	EP Inlet Temp Deg F	189°F	184	187	189	190	186		
E.P.	EP Outlet Temp Deg F	151°F	147	148	150	150	149		
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X		
E.P.	FAN DAMPER POSITION	88%	88%	88%	88%	88%	88%		
E.P.	FAN AMPS	30A	30A	30A	30A	30A	30A		
E.P.	Field 1 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF		
E.P.	Field 2 kV/mA (AUTO)	34/12	33/13	34/13	34/13	35/12	35/12		
E.P.	Field 3 kV/mA (AUTO)	25/13	25/10	25/14	29/13	29/14	27/15		
E.P.	Field 4 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF		
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	Field 2 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	Field 3 MIST PRESSURE	8 PSIG	8	8	8	8	8		
EP	Field 4 MIST PRESSURE	OFF	OFF	OFF	OFF	OFF	OFF		
E.P.	EP OPACITY								
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60/>9 GPM	60/>9	60/>9	60/>9	60/>9	60/>9		
E.P.	PHOTOS TAKEN			1420					

NOTES: 2 NOZZLES ARE IN THE DUCT LANCE (ONE AIMED UPSTREAM / ONE DOWNSTREAM).
WATER SAMPLE TAKEN AT 1422 HRS. GOOD BAGGASSE.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 6 Date: 1/19/94

Unit No.: BOILER #4

(START TIME 1614) (STOP TIME 1716)

LOCATION	Time	1614	1624	1634	1644	1654	1704		
C.R.	AIR FLOW OUT (GREEN PEN)	920°F	920	X	920	X	914		
C.R.	STEAM OUT TEMP (BLUE PEN)	795°F	795	X	795	X	782		
C.R.	Steam rate OUT (RED PEN)	294 klb/hr	296	X	300	X	294		
C.R.	Steam Out Pressure	620 psi	630	X	620	X	630		
C.R.	SIX BOILER STEAM OUTLET LOADING	848800 lb/hr	877000	X	875400	X	880700		
C.R.	FEEDER SPEED RPM 1 2 3	13 10 13	12 11 13	X	13 9 13	X	13 10 13		
C.R.	FEEDER SPEED RPM 4 5 6	11 11 8	10 11 7	X	11 12 8	X	11 11 8		
E.P.	DUCT PRESSURE (EP IN)	10" MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX		
E.P.	EP Inlet Temp Deg F	196°F	193	195	197	197	197		
E.P.	EP Outlet Temp Deg F	149°F	150	150	151	150	151		
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X		
E.P.	FAN DAMPER POSITION	99%	99%	99%	99%	99%	99%		
E.P.	FAN AMPS	31 A	31 A	31 A	31 A	31 A	31 A		
E.P.	Field 1 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF		
E.P.	Field 2 kV/mA	35/12	35/11	35/11	32/9	33/9	33/9		
E.P.	Field 3 kV/mA	28/13	28/12	27/12	28/12	28/12	28/11		
E.P.	Field 4 kV/mA	27/13	27/14	26/18	28/14	28/14	28/15		
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8		
E.P.	Field 2 MIST PRESSURE	8	8	8	8	8	8		
E.P.	Field 3 MIST PRESSURE	8	8	7	7	7	7		
EP	Field 4 MIST PRESSURE	8	8	8	8	8	8		
E.P.	EP OPACITY								
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60 PSIG >9 GPM	60/>9	60/>9	60/>9	60/>9	60/>9		
E.P.	PHOTOS TAKEN			1638					

NOTES: TOOK EP SUPPLY SAMPLE AT 1635.
TOOK EP DISCHARGE SAMPLE AT 1640.
GOOD BAGGASSE.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 7 Date: 1/20/94

Unit No.: BOILER #4

START TIME 814 STOP TIME 915

LOCATION	Time	815	825	835	845	855	905	915	
C.R.	AIR FLOW OUT (GREEN PEN)	914°F	914	914	914	X	914	914	
C.R.	STEAM OUT TEMP (BLUE PEN)	788°F	800	793	795	X	780	780	
C.R.	Steam rate OUT (RED PEN)	266 klb/hr	274	287	287	X	294	294	
C.R.	Steam OUT Pressure	635 psi	615	620	628	X	625	620	
C.R.	SIX BOILER STEAM OUTLET LOADING	867700 lb/hr	887600	887700	874500	X	863700	896700	
C.R.	FEEDER SPEED (RPM) 1 2 3	11 11 12	11 11 12	11 11 12	11 10 12	X	11 11 12	11 10 12	
C.R.	FEEDER SPEED (RPM) 4 5 6	10 9 8	11 12 9	10 12 9	10 12 9	X	10 12 9	11 11 9	
E.P.	DUCT PRESSURE (EP IN)	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	
E.P.	EP Inlet Temp Deg F	190°F	191	188	186	185	186	177	
E.P.	EP Outlet Temp Deg F	149°F	150	150	149	149	150	144	
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	
E.P.	FAN DAMPER POSITION	98%	98%	98%	98%	98%	98%	98%	
E.P.	FAN AMPS	30A	30A	30	30	30	30	30	
E.P.	Field 1 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 2 kV/mA (AUTO)	35/12	34/13	35/12	35/13	35/12	34/13	26/27	
E.P.	Field 3 kV/mA (AUTO)	23/25	24/23	22/20	24/27	20/26	20/24	20/25	
E.P.	Field 4 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
E.P.	Field 2 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
E.P.	Field 3 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
EP	Field 4 MIST PRESSURE	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	EP OPACITY	5-10%							
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60 PSIG 79 GPM	60/79	60/79	60/79	60/79	60/79	60/79	
E.P.	PHOTOS TAKEN	815							

NOTES: F4 MIST IS OFF. CLOUDY/COOL. EP DISCHARGE SAMPLE AT 827 HRS. EP SUPPLY SAMPLE TAKEN AT 837. GOOD BAGGASSE.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 8 Date: 1/20/94

Unit No.: BOILER #4

START TIME 1014 STOP TIME 1116

LOCATION	Time	1016	1025	1035	1045	1055	1105	1112	
C.R.	AIR FLOW OUT (GREEN PEN)	810°F	815	810	X	810	810	X	
C.R.	STEAM OUT TEMP (BLUE PEN)	780°F	780	780	X	800	800	X	
C.R.	Steam rate OUT (RED PEN)	294 Klb/hr	294	294	X	294	294	X	
C.R.	Steam OUT Pressure	620 psi	610	600	X	630	620	X	
C.R	SIX BOILER STEAM OUTLET LOADING	898700 lb/hr	900600	896700	X	878300	882000	X	
C.R.	FEEDER SPEED (RPM) 1 2 3	11 10 12	11 10 12	11 11 12	X	11 10 12	11 11 12	X	
C.R.	FEEDER SPEED (RPM) 4 5 6	10 12 9	11 12 8	11 11 8	X	11 11 9	11 12 9	X	
E.P.	DUCT PRESSURE (EP IN)	10" MAX	10MAX	10 MAX	10MAX	10MAX	10MAX	10MAX	
E.P.	EP Inlet Temp Deg F	183°F	182	182	182	184	185	185	
E.P.	EP Outlet Temp Deg F	147°F	147	146	146	148	149	149	
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	
E.P.	FAN DAMPER POSITION	98 %	98	98	98	98	98	98	
E.P.	FAN AMPS	30 A	30	30	30	30	30	30	
E.P.	Field 1 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 2 kV/mA (AUTO)	33/11	34/12	35/12	34/13	34/12	34/12		
E.P.	Field 3 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 4 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
E.P.	Field 2 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
E.P.	Field 3 MIST PRESSURE	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 4 MIST PRESSURE	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	EP OPACITY		5-10%						
C.R.	Grate Rake								
C.R.	Soot Blower								
E.P.	DUCT LANCE PRES/FLOW	60 PSIG >9 GPM	60/>9	60/>9	60/>9	60/>9	60/>9	60/>9	
E.P.	PHOTOS TAKEN		1029						

NOTES: CLOUDY. TOOK EP DISCHARGE SAMPLE AT 1030 HRS. BAGASSE IS 50-50. BOILER SWING AT 1107 FROM 294 Klb/hr to 266.

UNITED STATES SUGAR PROCESS & MOBILE TEST INFO

Test No.: WET EP TEST 9 Date: 1-20-94

Unit No.: BOILER 4

TEST START 1209 TEST STOP 1310

LOCATION	Time	1210	1220	1230	1240	1250	1300	1307	
C.R.	AIR FLOW OUT (GREEN PEN)	914°F	914	914	914	914	914	914	
C.R.	STEAM OUT TEMP (BLUE PEN)	820°F	780	790	790	790	790	790	
C.R.	Steam rate OUT (RED PEN)	294 Klb/hr	290	281	285	280	290	294	
C.R.	Steam OUT Pressure	630 psi	630	610	615	625	640	640	
C.R	SIX BOILER STEAM OUTLET LOADING	910000 lb/hr	923800	908000	918600	885500	888400	885500	
C.R.	FEEDER SPEED (RPM) 1 2 3	12 10 12	11 10 12	12 10 12	11 11 12	12 11 12	12 10 12	11 10 12	
C.R.	FEEDER SPEED (RPM) 4 5 6	11 12 9	11 11 9	11 11 9	11 12 9	11 12 9	10 11 9	10 12 8	
E.P.	DUCT PRESSURE (EP IN)	10" MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	10 MAX	
E.P.	EP Inlet Temp Deg F	151°F	152	151	151	151	150	150	
E.P.	EP Outlet Temp Deg F	149	151	151	151	151	151	150	
E.P.	% Oxygen Boiler/EP	X	X	X	X	X	X	X	
E.P.	FAN DAMPER POSITION	98%	98	98	98	98	98	98	
E.P.	FAN AMPS	30 A	30	30	30	30	30	30	
E.P.	Field 1 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 2 kV/mA (AUTO)	35/13	35/12	35/12	35/12	35/12	35/11	35/11	
E.P.	Field 3 kV/mA (AUTO)	29/12	29/13	29/14	28/11	26/14	27/13	27/13	
E.P.	Field 4 kV/mA	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	Field 1 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
E.P.	Field 2 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
E.P.	Field 3 MIST PRESSURE	8 PSIG	8	8	8	8	8	8	
EP	Field 4 MIST PRESSURE	OFF	OFF	OFF	OFF	OFF	OFF	OFF	
E.P.	EP OPACITY								
C.R.	Grate Rake								
C.R.	Soot Blower		1233	→	→	1249			
E.P.	DUCT LANCE PRES/FLOW	60 PSIG >9 GPM	60/>9	60/>9	60/>9	60/>9	60/>9	60/>9	
E.P.	PHOTOS TAKEN		1216						

NOTES: CLOUDY. SAMPLE OF EP DISCHARGE WAS TAKEN AT 1236. VERIFIED THAT EP INLET T/C WAS READING CORRECTLY BY USING A TEMP METER. BAGASSE SO-SO.

APPENDIX 3

Dry EP Rapping Matrix

JOB NO. ____ JOB NAME U.S. SUGAR CORP.

United McGill Corporation

calculation sheet

M. DEMECHKO
originated by ____ date ____

SUBJECT RAPPING MATRIX
REV 3

checked by ____ date ____

SHEET ____ OF ____

MON

		1D	1C	2D	2C	3D	3C	4D	4C	
12	04									
12	12									← TEST 1 START 1215
12	20									
12	28	X								
12	36		X							
12	44			X						
12	52				X					
13	00					X				
13	08						X			
13	16									← TEST 1 STOP 1320
13	24									
13	32	X								
13	40		X							
13	48									
13	56									
14	04									
14	12									
14	20									
14	28									
14	36	X								
14	44		X							
14	52			X						
15	00				X					
15	08									
15	16									
15	24									
15	32									← TEST 3 START 1534
15	40	X								
15	48		X							
15	56									

		1D	1C	2D	2C	3D	3C	4D	4C	
16	04									
16	12									
16	20									
16	28							X		
16	36								X	← TEST 3 STOP 1637
16	44	X								
16	52		X							
17	00			X						
17	08				X					
17	16					X				
17	24						X			
17	32									
17	40									
17	48	X								
17	56		X							
18	04									
18	12									
18	20									
18	28									
18	36									
18	44									
18	52	X								
19	00		X							
19	08			X						
19	16				X					
19	24									
19	32									
19	40									
19	48									
19	56	X →								

		1D	1C	2D	2C	3D	3C	4D	4C
20	04 →		X						
20	12								
20	20								
20	28								
20	36								
20	44								
20	52								
21	00	X							
21	08		X						
21	16			X					
21	24				X				
21	32					X			
21	40						X		
21	48								
21	56								
22	04	X							
22	12		X						
22	20								
22	28								
22	36								
22	44								
22	52								
23	00								
23	08	X							
23	16		X						
23	24			X					
23	32				X				
23	40								
23	48								
23	56								

United McGill Corporation

calculation sheet

JOB NO.

JOB NAME U.S. SUGAR CORP.

M. DEMECHKO
originated by date

SUBJECT RAPPING MATRIX

checked by date

SHEET OF

TUE

	1D	1C	2D	2C	3D	3C	4D	4C		1D	1C	2D	2C	3D	3C	4D	4C		1D	1C	2D	2C	3D	3C	4D	4C
00 04									04 04									08 04				X				
00 12	X								04 12									08 12								
00 20		X							04 20									08 20								
00 28									04 28	X								08 28								
00 36									04 36		X							08 36								
00 44									04 44									08 44	X							
00 52									04 52									08 52		X						
01 00							X		05 00									09 00								
01 08								X	05 08									09 08								
01 16	X								05 16									09 16								
01 24		X							05 24									09 24								
01 32			X						05 32	X								09 32							X	
01 40				X					05 40		X							09 40								X
01 48					X				05 48			X						09 48	X							
01 56						X			05 56				X					09 56		X						
02 04									06 04					X				10 04			X					
02 12									06 12						X			10 12				X				
02 20	X								06 20									10 20					X			
02 28		X							06 28									10 28						X		
02 36									06 36	X								10 36								
02 44									06 44		X							10 44								
02 52									06 52									10 52	X							
03 00									07 00									11 00		X						
03 08									07 08									11 08								
03 16									07 16									11 16								
03 24	X								07 24									11 24								
03 32		X							07 32									11 32								
03 40			X						07 40	X								11 40								
03 48				X					07 48		X							11 48								
03 56									07 56			X						11 56	X							

TEST 8 START 0958

TEST 8 STOP 1101

United McGill Corporation

calculation sheet

JOB NO. ______ JOB NAME: U.S. SUGAR CORP.

M. DEMECHKO (originated by) date ______ SUBJECT: RAPPING MATRIX

checked by ______ date ______

SHEET ______ OF ______

TUE

Time	1D	1C	2D	2C	3D	3C	4D	4C
12 04	→	X						
12 12			X					
12 20				X				
12 28								
12 36								
12 44								
12 52								
13 00	X							
13 08		X						
13 16								
13 24								
13 32								
13 40								
13 48								
13 56								
14 04	X							
14 12		X						
14 20			X					
14 28				X				
14 36					X			
14 44						X		
14 52								
15 00								
15 08	X							
15 16		X						
15 24								
15 32								
15 40								
15 48								
15 56								

TEST 7 START 1300

TEST 7 STOP 1403

TEST 9 START 1550

Time	1D	1C	2D	2C	3D	3C	4D	4C
16 04								
16 12	X							
16 20		X						
16 28			X					
16 36				X				
16 44								
16 52								
17 00								
17 08								
17 16	X							
17 24		X						
17 32								
17 40								
17 48								
17 56								
18 04							X	
18 12								X
18 20	X							
18 28		X						
18 36			X					
18 44				X				
18 52					X			
19 00						X		
19 08								
19 16								
19 24	X							
19 32		X						
19 40								
19 48								
19 56								

TEST 9 STOP 1651

Time	1D	1C	2D	2C	3D	3C	4D	4C
20 04								
20 12								
20 20								
20 28	X							
20 36		X						
20 44			X					
20 52				X				
21 00								
21 08								
21 16								
21 24								
21 32	X							
21 40		X						
21 48								
21 56								
22 04								
22 12								
22 20								
22 28								
22 36	X							
22 44		X						
22 52			X					
23 00				X				
23 08					X			
23 16						X		
23 24								
23 32								
23 40	X							
23 48		X						
23 56								

FORM NO. CS79 LITHO IN U