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July 21, 2003

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BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Attention: Mr. Jeffery Koerner, P. E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – CLEWISTON MILL
PROPOSED NEW BOILER NO. 8
DEP PROJECT NO. 0510003-021-AC (PSD-FL-333)
ADDITIONAL INFORMATION RESPONSE #3

Dear Mr. Koerner:

Thank you for meeting with me and representatives of U. S. Sugar on May 28th regarding the Boiler No. 8 PSD permit application. During the meeting, and in a follow-up letter dated June 16, 2003, the Department requested certain additional information in order to complete the review of the application. The additional information requested is provided below.

1. **SNCR System**

The current design for Boiler No. 8 is for the uncontrolled NO_x emissions to be in the range of 0.24 to 0.28 lb/MMBtu. This is in part a result of the necessity to design the boiler for low CO emissions. U. S. Sugar has proposed a CO emissions limit of 363 ppmvd @ 7% O2 (467 ppmvd @ 3% O2), equivalent to 0.38 lb/MMBtu. This limit is much lower than the current limit of 0.7 lb/MMBtu for Boiler No. 7 at Clewiston. The upcoming MACT standards for new industrial boilers could result in even a lower CO limit (the proposed MACT limit is 400 ppmvd @ 3% O2, equivalent to about 0.32 lb/MMBtu, which is lower than U. S. Sugar's proposed limit). We believe the uncontrolled NO_x emissions range for Boiler No. 8 is higher than the design of the New Hope Power Partnership boilers, which were constructed about 8 years ago, because of the necessity to design the boiler for low CO emissions. In fact, Boiler No. 8 will be designed much differently than the New Hope Power boilers.

The Department claims that there is substantial information available from wood/bagasse fired boilers proving that SNCR is capable of consistently reducing NO_x by 40% to 50%. The only plant that we know of is Okeelanta/New Hope Power, which almost continuously burns a 50/50 mixture of wood and bagasse to maintain combustion stability and even out the fluctuations in the bagasse quality. The Department also makes no mention of the ammonia slip levels.

The Department states that it does not distinguish between wood and bagasse as a fuel. It is possible to do this if one analyzes the fuel on a dry, ash free basis, but not when evaluating the fuel on an 'as-fired' basis. Bagasse, unlike wood, is largely dependent upon an upstream process to determine the 'as-fired' fuel quality. The final moisture of the bagasse, during the crop season, is dependent upon the mill operation (i.e., throughput, amount of imbibition water added, the condition of the mill rolls, the roll settings, etc.). During the off-crop season, when bagasse is fed from the outside storage area, the moisture constant is dependent on the moisture content when placed into storage, the time in storage, and the weather conditions during that time. During dryer periods, the moisture content can be much lower than during dryer periods, contributing to higher uncontrolled NO_x emissions from the boiler.

The ash content in the bagasse is also variable and affects the 'effective moisture' of the bagasse. A higher ash content for a given fuel moisture makes the fuel more difficult to burn and therefore affects the required excess air ratios and overfire air distribution. As described previously to the Department, the Clewiston mill sugarcane is grown primarily on "sand" lands, and the resulting bagasse contains sand (which also ends up in the ash), which also contributes to this variability.

In summary, it is the significant variability in the bagasse fuel quality that makes it difficult to maintain consistently low uncontrolled NO_x emissions.

The 'process dependency' of bagasse quality in itself suggests that bagasse is distinct from wood. The moisture and ash content of wood is also variable but it tends to be consistent for a particular source. This makes the boiler combustion control much more manageable and ultimately leads to more consistent uncontrolled emissions.

The primary reason for NOT selecting a water-cooled grate was one of emissions control. The ash removal mechanism of a water-cooled vibratory grate is to shake the grate through an eccentric or cam mechanism. This periodic 'shaking' causes higher particulate and CO emissions and therefore also influences uncontrolled NO_x emissions. In addition to the 'shaking' problem, the suppliers of the water cooled grates require a higher undergrate air temperature than has been selected for the Boiler No. 8 design. The higher undergrate air temperature aggravates uncontrolled NO_x as it increases the primary flame temperature.

The Boiler No. 8 furnace (as designed) has been modelled using Computational Fluid Dynamics (CFD). Thermal Energy Systems (TES), the firm designing Boiler No. 8, states that the results of the CFD modelling confirm the correct selection of the furnace geometry and the overfire air configuration for stable combustion and optimum CO emissions. However, NO_x modelling of solid fuel-fired boilers is extremely complex, and while some claim to have resolved this, TES has doubts as to whether CFD predictions of uncontrolled NO_x emissions can be used as a basis for specifying uncontrolled NO_x limits. Their understanding of the state of art is that, at best, some people claim that NO_x modelling can be used to obtain relative numbers from a given geometry but not absolute numbers.

Excess air is a function of the 'effective' fuel moisture. Low excess air cannot be used when burning a high moisture biomass fuel in suspension because the fuel tends to pile on the grate. This comes back to the variable quality of bagasse and the difficulty in maintaining ideal combustion conditions consistently with a variable process. For example, if one designs the boiler for a low moisture fuel, trouble will be encountered as soon as the moisture increases by a couple of percentage points. On the other hand, if the boiler is designed for burning a high moisture fuel, the uncontrolled NO_x emissions will increase as soon as the fuel moisture drops appreciably below the design level.

Flue gas recirculation is normally used to quench the flame, reducing both temperature and oxygen levels, thereby reducing the uncontrolled NO_x emissions. The problem with using flue gas recirculation on a bagasse boiler is the ability to maintain a high enough flame temperature to maintain combustion. For this reason, we do not believe flue gas recirculation is an option for a bagasse-fired boiler.

In summary, the above discussion underscores the uncertainty of predicting uncontrolled NO_x emissions from a highly variable fuel. The best estimate is still in the range of 0.24 to 0.28 lb/MMBtu. However, in order to account for this variability, increasing the averaging time associated with any NO_x limit is necessary, to avoid short-term excursions.

Based on the current boiler design, additional information regarding the performance of the SNCR system proposed for Boiler No. 8 is presented in the attached letter from Fuel Tech (Attachment A). FTI states that at an uncontrolled emission rate of 0.28 lb/MMBtu, a controlled NO_x emission rate of 0.19 lb/MMBtu is achievable on a continuous basis (equivalent to 32% NO_x reduction). However, we have also received a quote from another SNCR vendor, De-NO_x Technologies (DNT). DNT has quoted a NO_x removal efficiency of 50% at an uncontrolled NO_x level of 0.24 lb/MMBtu (also attached).

Based on this information, and assuming an average uncontrolled NO_x emission rate as high as 0.28 lb/MMBtu, U. S. Sugar believes it can meet an NO_x limit of 0.14 lb/MMBtu based on a 12-month rolling average, excluding startup, shutdown and malfunction. The 12-month rolling average limit is requested in order to account for the variability in boiler operating conditions and fuel conditions, as described above and in the FTI letter. It is the variability of the process and the fuel quality under normal operating conditions that makes the controlled figure of 0.14 lb/MMBtu impossible to meet on a continuous basis. Achieving greater than 50 percent NO_x reduction on a continuous basis may not be achievable based on the bagasse fuel characteristics, limited reactant residence time, changing boiler loads, etc. However, we believe this may be achievable on an average basis.

The proposed limit is lower than New Hope Power's NO_x limit of 0.15 lb/MMBtu. We therefore believe this represents a significant advancement in NO_x reduction, given the higher uncontrolled emissions, fuel variability, and other factors for Boiler No. 8.

The proposed lower NO_x limit as a 12-month rolling average requires that portions of the PSD application be revised. These revisions are presented in Attachment B.

2. **Excess Emissions From Boiler No. 8**

Further Description of Startup and Shutdown Conditions
The anticipated startup/shutdown procedures for Boiler No. 8 were presented in Attachment UC-EU1-J6 of the permit application form. Further information is presented below regarding the startup and shutdown procedures in order to better address potential excess emissions during startup.

In a normal start-up, Boiler No. 8 will be started on fuel oil. One burner will be used (and from time to time will shut it down if the temperature rise is too fast) to bring the boiler up in approximately 4 to 5 hours at a superheater steam temperature rise of about 100 to 120 deg. F per hour. Once a steam temperature of about 500 deg. F is reached, bagasse is fed onto the grate until a fire is established across the entire grate. Full steaming rate is usually reached in about 30 to 60 minutes after bagasse begins to be fed to the boiler. Normally the ESP is started before any of the fuel oil burners are lit, and always before any bagasse is fed onto the grate. The ESP requires about 30 to 60 minutes of purging using ambient air prior to activation.

To initiate shutdown, the bagasse fuel feed is terminated. The air pollution control equipment is not shutdown until the fuel flow is stopped.

It is estimated, based on past experience and the year-around use of Boiler No. 8, that the boiler will have 4 to 6 cold starts and 6 to 8 warm starts per year. This could vary depending on weather conditions, plant operating conditions, boiler maintenance requirements, etc.

Anticipated emissions during startup and shutdown conditions are described below.

PM Emissions and Opacity
The wet sand separator is activated prior to startup beginning, and the ESP is activated prior to introducing any bagasse to the boiler. Only fuel oil is burned until the ESP is activated. As a result, excess PM emissions are minimized during startup. Combustion conditions when initially firing fuel oil may not be optimum, therefore higher emissions than 0.026 lb/MMBtu may result. However, the fuel input and boiler

load are low during such conditions. Therefore, the maximum mass emissions stated in the application (26.8 lb/hr) should not be exceeded during startup.

Since combustion conditions during startup may not be optimum, there is a possibility for excess opacity. Setting in operation of the ESP prior to firing any bagasse, along with firing fuel oil only initially, will minimize any excess opacity from the stack serving Boiler No. 8. Opacity during startup is expected to be below 20 percent most of the time, but wet fuel may cause some short-term excursions.

During shutdown, the bagasse fuel input is terminated and the remaining bagasse on the grate is combusted. The wet sand separator and ESP continue to operate, and adequate combustion air is provided to complete combustion. Therefore, no excess PM or opacity emissions are expected during shutdown.

NO_x Emissions

NO_x emissions in excess of the proposed limit of 0.14 lb/MMBtu are not expected to occur provided the limit is on a 12-month rolling average. However, this level could be exceeded on a short-term basis during boiler startup. The SNCR system cannot be activated until the appropriate temperature window within the boiler is achieved. This temperature window is expected to be achieved within about 4 to 5 hours of initial fuel firing, when the boiler is burning fuel oil. During this time, the fuel input and boiler load are gradually increased. In addition, furnace temperatures are lower during such periods, thereby limiting NO_x emissions. Therefore, the maximum short-term NO_x mass emissions stated in the application (0.28 lb/MMBtu and 288.4 lb/hr, as revised through this submittal) should not be exceeded during startup.

During shutdown, the bagasse fuel input is terminated and the remaining bagasse on the grate is combusted. The SNCR system continues to operate as long as the appropriate temperature window is maintained in the boiler. Therefore, no excess NO_x emissions are expected during shutdown.

During all hours of boiler operation, the SNCR system will be operated automatically based on furnace temperatures and the NO_x continuous emissions monitoring system (CEMS). Once temperatures in the furnace are correct for reactant injection, the system will automatically feed the appropriate amount of reactant to maintain emissions at 0.14 lb/MMBtu on an average basis.

It is noted that since a CEMS for NO_x will be required, U. S. Sugar will be able to quantify emissions during startup and shutdown after the boiler begins operating, based on actual operation of the boiler.

CO and VOC Emissions

CO and VOC emissions from Boiler No. 8 are expected to behave in a similar manner, as both are dependent upon good combustion. Therefore, the following discussion will apply to both of these pollutants.

Normally, only fuel oil is burned during initial startup of the boiler. This is to heat up the boiler and the ESP, and to develop the appropriate temperature window in the boiler. Burning fuel oil only during this period minimizes emissions of CO/VOC. CO levels when burning fuel oil are expected to be low. CO/VOC tends to increase when starting to burn bagasse, especially if the bagasse is wet. To minimize emissions, the startup period is minimized by bringing the boiler on-line and up to steam rate as quickly as possible, and following good combustion practices, as described in the application.

The maximum CO emissions stated in the application (6.5 lb/MMBtu for 1-hour and 4.5 lb/MMBtu for 8-hr average, equivalent to about 6,200 ppm and 4,300 ppm @ 7% O_2, respectively) are the highest expected during startup or shutdown. These emissions are based on CEM data for New Hope Power Partnership boilers. These maximum emissions were included in the air quality modeling analysis, and it was demonstrated that such emissions would not result in adverse air quality impacts. It is not expected that this level of emissions will be exceeded during startup or shutdown of the new boiler. Also, the fuel input and boiler load are lower during such conditions. Therefore, the maximum mass emissions of 6,695 lb/hr for CO and 61.8 lb/hr for VOC, as stated in the application, should not be exceeded during startup.

During shutdown, the bagasse fuel input is terminated and the remaining bagasse on the grate is combusted. Adequate combustion air is provided to complete combustion. Therefore, no excess CO/VOC emissions are expected during shutdown.

It is noted that since a process monitor for CO will be required, U. S. Sugar will be able to quantify emissions during startup and shutdown after the boiler begins operating, based on actual operation of the boiler.

Exclusion of Excess Emissions During Startup/Shutdown Conditions
Since startup and shutdown conditions do not represent the normal operation of the boiler, and excess emissions may occur during such periods, it is requested that emissions during these periods be excluded from the lb/MMBtu emission limits. A CEMS will be required for CO and NO_x. Including startup/shutdown emissions for compliance purposes would make it difficult to meet such limits. It is noted that startup/shutdown emissions have be excluded from compliance with emission limits for other similar wood/bagasse-fired boilers, such as for New Hope Power Partnership. The Florida air rules specifically allow excess emissions due to startup, shutdown or malfunction, for up to two hours in any 24-hour period, provided the magnitude and duration of such periods is minimized to the extent practicable (Rule 62-210.700, F. A. C.).

For Boiler No. 8, U. S. Sugar proposes to define the startup period as the period until steam generation reaches 300,000 lb/hr (about 60% of maximum steam load). This is based on the expected turndown ratio for the boiler.

The following permit conditions are recommended for Boiler No. 8. These conditions are structured after New Hope Power's latest PSD permit.

Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction of Boiler No. 8.

a. *Definitions*

1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

2) Startup is the commencement of operation of the boiler after a shut down or cessation of operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for Boiler No. 8 shall end once steam generation reaches 300,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

3) Shutdown is the cessation of the operation of Boiler No. 8 for any purpose after steam generation drops below 300,000 pounds per hour.

4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of excess emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the boiler.

1) Distillate oil or clean wood shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the ESP has been adequately purged, as recommended by the ESP manufacturer, it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. XX. The ESP shall be on line and functioning properly before firing any bagasse. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown.

2) Hourly NO_x emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 12-month compliance averages. No more than six (6) hourly emission rate values shall be excluded in a 24-hour period due to a cold startup. No more than three (3) hourly emission rate values shall be excluded in a 24-hour period due to a warm startup. No more than two (2) hourly emission rate values shall be excluded in a 24-hour period due to a malfunction. No more than two (2) hourly emission rate values shall be excluded in a 24-hour period due to a shutdown. No more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) To "document" a malfunction during which excess emissions occurred, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions associated with excess emissions, that occurred during the year for the boiler. The report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

3. **Alternative Opacity Monitoring Plan**

In the application, U. S. Sugar presented an Alternative Opacity Monitoring Plan to be implemented in lieu of a continuous opacity monitoring system (COMS). The Department has indicated that despite the fact that a COMS may not be required by the NSPS, there may be other reasons to require the COMS, i.e., as a surrogate for PM emissions. However, U. S. Sugar believes that there are additional reasons for not requiring a COMS on Boiler No. 8. These reasons are as follows:

- The stack gas constituents are not conducive to accurate opacity readings. The stack gases will contain significant moisture, i.e., 20 percent or more by volume. Unreacted urea may be present. Ammonia and ammonia compounds will be present, including ammonium bisulfate, which is known to have a high reflectance. All of these compounds can result in inaccurate opacity readings by the COMS.

- There is no demonstrated correlation between opacity and PM emissions for a solid-fueled boiler. No such correlations are known to have even been attempted for a bagasse-fired boiler.

- Boiler No. 8 will be subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR Part 64. As such, U. S. Sugar will be required to investigate and propose surrogate parameters for monitoring PM on a continuous basis. CAM would apply to the new boiler upon inclusion in the Title V operating permit.

- Boiler No. 8 will have a CEMS for CO, as part of good combustion practices (GCPs) for the boiler. Corrective action will be required if the CO exceeds a specified level. Since GCPs, CO, PM and opacity are all related, having the CO monitor renders an opacity monitor as less important in ensuring that good combustion is taking place.

After the new Boiler No. 8 is started up, U. S. Sugar will investigate surrogate parameters for PM emissions, and propose the surrogate parameters along with parameter ranges as part of the Title V revision application. The tentative monitoring approach would be to use ESP power as the indicator of PM emissions. The CAM rules, as described at 40 CFR 64.4(d) and (e), provide for an adequate amount of time to install and test necessary monitoring equipment, including the submission of a test plan and schedule to obtain performance data. U. S. Sugar will conduct a testing program to determine if ESP power is a reliable indicator of actual PM emissions. Initial testing will be completed within 90 days of initial compliance testing of the boiler. The results of the testing as well as the selected indicator parameter ranges will be submitted to the Department with the Title V permit application. The preliminary monitoring approach is summarized in the following table.

	Indicator No. 1
Indicator	ESP secondary voltage and current are measured for each field to determine the total power to the ESP.
Measurement Approach	The secondary voltage is measured using a voltmeter and the secondary current is measured using an ammeter. The total power (P expressed as kW) input to the ESP is the sum of the products of the secondary voltage (V) and current (I) in each field. ($P = V_1I_1 + V_2I_2 + \ldots + V_nI_n$)
Indicator Range	An excursion is defined as an ESP power input less than a minimum kW (to be determined). Excursions trigger an inspection, corrective action, and a reporting requirement.
Data Representative-ness	The voltage and current are measured using standard instrumentation provided for this purpose.
Verification of Operational Status	NA
QA/QC Practices and Criteria	Confirm the meters read zero when the unit is not operating.
Monitoring Frequency	The secondary voltage and current are measured continuously and used to calculate the power input every 15 minutes.
Data Collection Procedures	The hourly average power input is calculated and recorded.
Averaging Period	1-hour block averaging period.

ESP parameters are generally recognized indicators of PM emissions. In an ESP, electric fields are established by applying a direct-current voltage across a pair of electrodes, a discharge electrode and a collection electrode. Particulate matter suspended in the gas stream is electrically charged by passing through the electric field around each discharge electrode (the negatively charged electrode). The negatively charged particles then migrate toward the positively charged collection electrodes. The particulate matter is separated from the gas stream by retention on the collection electrode. Particulate is removed from the collection plates by shaking or rapping the plates.

Generally, ESP performance improves as total power input increases. This relationship holds true when PM and gas stream properties (such as PM concentration, size distribution, resistivity, and gas flow rate) remain stable and all equipment components (such as rappers, plates, wires, hoppers, and transformer-rectifiers) operate satisfactorily.

The secondary voltage drops when a malfunction, such as grounded electrodes, occurs in the ESP. When the secondary voltage drops, less particulate is charged and collected. Also, the secondary voltage can remain high but fail to perform its function if the collection plates are not cleaned, or rapped, appropriately. If the collection plates are not cleaned, the current drops. Thus, since the power is the product of the voltage and the current, monitoring the power input will provide a reasonable assurance that the ESP is functioning properly. Problems that may not be detected by monitoring other parameters individually will be manifested in the total power input.

The indicator ranges will be determined through a testing program. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported.

It is noted that EPA and EPRI are conducting ongoing studies regarding PM emissions and ESP operating parameters. By the time that the new Boiler No. 8 is started up, additional knowledge should exist regarding the relationship between PM emissions and ESP parameters. As a result, the tentative plan presented above is subject to change.

Based on the above plan, we request that a COMS not be required for Boiler No. 8, and the Alternative Monitoring Plan be adopted.

4. **Air Quality Modeling Analysis**

Based on the Department's comments, the building dimensions used in the modeling have been revised to match the aerial photograph submitted with the application. The modeling has been re-executed for PM_{10} based on DEP's request, and the revised results are presented in Attachment C. These results change, if at all, from those presented in the original application.

5. **Gaseous Pollutant Concentrations**

Equivalent concentrations of gaseous pollutants are presented in the following table.

Pollutant	Emission Rate (lb/MMBtu)	Emission Rate (lb/hr)	Concentration @ 3% O2	Concentration @ 7% O2
Sulfur Dioxide	0.06	56.16	32 ppmvd	25 ppmvd
Nitrogen Oxides	0.14	131.0	104 ppmvd	82 ppmvd
Carbon Monoxide	0.38	356.0	467 ppmvd	363 ppmvd
Volatile Organic Compounds*	0.06	56.16	96 ppmvd	75 ppmvd

* Reported as carbon.

6. **Continuous CO Monitoring**

The Department has indicated that a continuous process monitor will be required on Boiler No. 8, and will be used to trigger corrective action when CO reaches a certain level in the boiler. This is the same type of monitoring currently required for Boiler No. 4 at Clewiston.

The MACT standards for industrial boilers, as currently proposed, require a continuous CO monitor that meets the requirements of 40 CFR 60, Appendix B, Performance Specification PS-4A. In addition, the quality assurance requirements of 40 CFR Appendix F would apply. It is our understanding that the CO limit under the industrial boiler MACT will be promulgated as a work practice standard, and will require corrective action when exceeded, but not be considered a violation unless corrective action is not initiated.

In light of these tentative requirements, U. S. Sugar will agree to installing a CO monitor capable of meeting the requirements of the MACT rule, but request that the monitor only be used as a process monitor with an associated action level.

7. **Baseline CO Emissions From Boiler No. 3**

Prior to 2002, the annual CO emissions reported for Boiler No. 3 in the Annual Operating Report (AOR) to DEP were based on a factor for wood waste combustion (13.6 lb/ton from Table 1.6-2 of AP-42). This factor had been used for many years previously by U. S. Sugar, and for consistency sake, they had continued to use this factor. However, beginning with the 2002 AOR, a CO emission factor based on test data from Boiler No. 3 was used (35.3 lb/ton or 4.9 lb/MMBtu), as this factor is more representative of actual emissions from the boiler. The test data upon which the factor is based are shown in the attached Table A. In preparing the application, we recalculated the 2001 CO emissions using the more appropriate factor. We believe these emissions are most representative of the actual emissions from Boiler No. 3.

8. **ESP Design Specifications**

The ESP vendors have provided preliminary scoping and budgeting information for the ESP. They have based their efficiency numbers on an assumed particulate matter (PM) inlet grain loading of 1.0 lb/MMBtu. Then, using our design specification of 0.026 lb/MMBtu at the outlet, they have provided the equivalent removal efficiency. However, the inlet grain loading could be substantially higher than 1.0 lb/MMBtu. There is little data available on the uncontrolled PM emissions from a bagasse-fired boiler. AP-42 presents a factor, which is shown in the application, of 15.6 lb/ton of wet bagasse fired, which is equivalent to about 2.4 lb/MMBtu, depending on heating value of the bagasse. However, another EPA publication presents a factor of 5.05 lb/MMBtu (Non-fossil Fuel Fired Industrial Boilers- Background Information, EPA-450/3-82-007, March 1982). Based on this higher uncontrolled factor, the ESP efficiency required would be 99.5%. These are details that will need to be worked out with the ESP vendor prior to actual vendor selection or signing a purchase agreement. The final agreement will contain performance guarantees, as opposed to the "expected performance".

In addition, Thermal Energy Systems has calculated the inlet dust loadings for a number of different conditions. For the design fuel (52 % moisture, 4 % ash) at 100 % MCR and for the worst-case EPS design (50 % moisture, 11 % ash) they are as follows:

Measuring point	**Units**	**Burden**	
		DESIGN FUEL	**ESP DESIGN**
Entry to ESP	lb/MMBTU	1.45	5.19
Exit from ESP	lb/MMBTU	0.026	0.026
Required ESP efficiency	%	98.2	99.5

These figures include an allowance for the moisture added by the urea. The ESP design includes a 30% allowance for upset conditions. As shown, the ESP design will be capable of achieving a 99.5% removal efficiency.

The opacity specification provided by the ESP vendors at this time is also an "expected performance", and not a firm guarantee. Regardless, even if a 10% opacity was guaranteed by a vendor, this should not translate directly into a permit limit. Guarantees are typically based on very specific assumed operating conditions. The guarantee applies only if specific operating conditions are met. Guarantees are usually satisfied in the contract by a single performance test, again at specified operating conditions. These tests are typically performed under the best operating conditions, when the equipment is new and in the best working order. Under actual day-to-day operations, conditions may be different. As a result, any permit limits must reflective of this.

Thank you for consideration of this additional information. Please call or e-mail me if you have any questions concerning this information.

Sincerely,
GOLDER ASSOCIATES INC.

David A. Buff

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

DB/jej

Enclosure

cc: Don Griffin
Ron Blackburn, DEP
C. Holladay
G. Worley, EPA
D. Bunyak, NPS

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Table A. CO Emission Tests Performed on Boiler No. 3- U.S. Sugar Corporation - Clewiston

Unit	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	CO Emissions (EPA Method 10) lb/hr	lb/MMBtu
Boiler 3	Fuel Cell	02/18/94	77,498	104,143	213.53	29.66	393.21	2.115
Boiler 3	Fuel Cell	02/18/94	74,595	114,429	234.27	32.54	321.63	1.590
Boiler 3	Fuel Cell	02/18/94	76,321	104,677	214.47	29.79	486.85	2.270
Boiler 3	Fuel Cell	01/10/95	80,337	109,662	222.08	30.84	302.26	1.361
Boiler 3	Fuel Cell	01/10/95	68,931	115,225	233.89	32.48	392.47	1.678
Boiler 3	Fuel Cell	01/10/95	72,747	112,974	228.50	31.74	482.70	2.112
Boiler 3	Fuel Cell	02/27/96	70,962	95,607	189.08	26.26	610.68	3.230
Boiler 3	Fuel Cell	02/27/96	73,300	89,679	176.36	24.49	261.72	1.484
Boiler 3	Fuel Cell	02/27/96	67,289	96,632	153.35	21.30	28.16	0.148
Boiler 3	Fuel Cell	02/28/96	70,659	102,130	178.97	24.86	94.62	4.714
Boiler 3	Fuel Cell	02/28/96	65,905	102,986	170.59	23.69	2063.82	10.225
Boiler 3	Fuel Cell	02/28/96	70,791	108,000	179.10	24.88	1443.73	6.811
Boiler 3	Fuel Cell	02/28/96	73,377	102,441	200.34	27.83	1742.13	8.696
Boiler 3	Fuel Cell	02/28/96	70,591	105,179	205.69	28.57	1275.01	6.199
Boiler 3	Fuel Cell	02/28/96	69,977	99,134	194.01	26.95	1619.93	8.350
Boiler 3	Fuel Cell	02/29/98		102,441	173.21	24.06	1742.13	10.058
Boiler 3	Fuel Cell	02/29/98		105,179	174.93	24.30	1275.00	7.289
Boiler 3	Fuel Cell	02/29/98		99,134	164.73	22.88	1619.33	9.830
	Number of Runs		15	18	18	18	18	18
	MEAN		**72,219**	**103,870**	**194.8**	**27.06**	**897.5**	**4.898**
	MINIMUM		65,905	89,679	153.4	21.30	28.2	0.148
	MAXIMUM		80,337	115,225	234.3	32.54	2,063.8	10.225

Notes:
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
TPH = tons per hour.

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

ATTACHMENT A

ADDITIONAL SNCR VENDOR INFORMATION

FUEL TECH
Technology for a renewed environment™

To Whom It May Concern:

Over the last six months, Fuel Tech, Inc. (FTI) has been working with U.S. Sugar Corporation and Thermal Energy Systems to develop a NOxOUT® SNCR system design capable of providing the best possible NOx reduction performance while maintaining some degree of operating flexibility for the new No. 8 boiler at the Clewiston Mill. The latest set of boiler design specifications, dated May 5, 2003, has been used by FTI to conduct a preliminary SNCR process evaluation covering a wide range of fuel conditions and baseline NOx concentrations.

In general, the result of our review indicates that NOxOUT® SNCR can provide a dependable and sustainable controlled NOx level of 0.15 lb/MMBtu for the "design" case and somewhat better performance for the other load cases, as long as certain operating conditions are made available to the SNCR process. Our review has covered a number of design parameters that are critical to the effectiveness of the SNCR process, including:

- Balance-of-plant impacts,
- Expected flue gas temperature at the point of injection,
- Access to the furnace and distribution of the urea reagent,
- CO concentration in the upper furnace,
- Residence time within the effective temperature window for the SNCR process,
- Baseline NOx concentration, and
- Ammonia slip.

While each of these parameters is critical to the SNCR process, FTI must take into consideration up-front potential balance-of-plant impacts that could affect plant operation. In particular, the expected size of the atomized urea droplets must be considered so as to avoid the potential impingement of liquid urea on the heat transfer surfaces. Under normal design conditions FTI would ensure that the urea droplets would completely evaporate, decompose into ammonia and isocyanic acid, and through reactions with the OH, O and H radicals, be converted to gas phase NH2 and NCO before entering the superheater region.

The selective, non-catalytic reactions occur in the gas phase between NH2 and NCO and various oxides of nitrogen. The process is optimized by releasing the reducing agent inside a temperature range within which significant NOx reduction can be obtained – this temperature range is known as the temperature window. Chemical release within the optimum temperature window ensures that the reducing agents will react with NOx and convert it to molecular nitrogen. If the chemical is released at temperatures higher than optimum, the reducing agent will oxidize into NOx. If the chemical is released at temperatures well below the optimum, the reactions will slow down significantly. Under the latter scenario, some ammonia from the original decomposition step of urea will not convert to NH2 but will survive intact, and be present downstream as "ammonia slip".

Given sufficient residence time to account for the reduced kinetic rates, reactions at lower temperatures typically lead to lower NOx levels. As mentioned above, however, these lower temperatures also lead to higher levels of ammonia slip, which generally is an undesirable byproduct. Fuel Tech tries to achieve maximum NOx reduction while maintaining low ammonia slip through the use of multiple injection levels and the careful selection of the spraying patterns developed through CFD and CKM modeling. Other owners of bagasse-fired boilers have experimented with larger than ideal urea droplets with extremely negative consequences. The larger droplets do not evaporate and decompose as quickly, and although the outlet NOx concentration may be lower, liquid urea may impinge on the tube surface and eventually eat through the boiler tube steel causing a leak and subsequent forced shutdown of the unit.

Other balance-of-plant considerations include the potential for ammonium bisulfate formation and visible emissions (ammonium chloride plume). These potential issues were taken into consideration for this application but since very little sulfur trioxide (except for light fuel oil firing) and/or hydrogen chloride would be present in the flue gas, these process-limiting impacts were dismissed.

As mentioned in the previous paragraphs, there are other design parameters and flue gas constituents that must be considered as part of the SNCR design process. For this application, we considered a high temperature in the injection zone of 2025°F for the low moisture bagasse case and a low temperature of 1600°F for the light fuel oil (LFO) and LFO/bagasse cases. Because of this wide range of temperatures and the need to maximize NOx reduction while limiting ammonia slip, FTI will be recommending three (3) levels of urea injectors to facilitate biasing of the injected reagent across the temperature window as necessary for optimum performance. Based on drawings of the proposed boiler we have reviewed, this furnace design offers an advantage over many of our existing installations – this furnace can be accessed at the lower two (2) injections levels from all four sides which will significantly aid in the distribution of the reagent.

Another other important consideration is the local concentration of CO within the specified temperature window. The design details indicate that the local CO will be limited to 400 ppm, but under various fuel and load conditions, we expect to see wide fluctuations in the CO concentration. It is important that outside of these fluctuations, the average concentration of CO stays near this design level.

When the NOxOUT® SNCR process was evaluated for this application, we used the projected concentration of 400 ppm in the post-combustion region of the furnace. The CO concentration is important in that when a higher than anticipated CO level is encountered, it changes the chemical environment and increases the formation of hydroxyl radicals, which are key components in the conversion of the ammonia and isocyanic acid to the reducing agents NH2 and NCO. If the temperature is relatively high, the NH2 will oxidize to NOx – an undesirable effect. In order to achieve effective NOx reduction, the chemical needs to be released at a lower temperature which is typically found closer to the furnace exit, with the net effect of reducing the residence time for the selective reactions.

In terms of expected NOx reduction performance and ammonia slip, our design analysis covered inlet NOx ranging from a maximum of 0.30 lb/MMBtu to a minimum of 0.20 lb/MMBtu. However, we placed the majority of our focus on the inlet NOx levels of 0.28 and 0.24 lb/MMBtu, which are more typical of the uncontrolled NOx levels we have seen in other bagasse-fired boilers.

Assuming that the uncontrolled NOx is 0.28 lb/MMBtu and the ammonia slip must be limited to 10 ppmv (average, as measured), our evaluation indicates that the best sustainable, controlled NOx for the design fuel and moisture is 0.18 lb/MMBtu. However, if the ammonia slip limit is relaxed to 25 ppmv, NOx can be controlled to just below 0.15 lb/MMBtu. The improved NOx reduction comes at the expense of a higher urea consumption rate and less effective chemical utilization, but we anticipate that the bulk of the ammonia will be removed in the scrubber and the actual concentration of ammonia leaving the stack will be much lower. Please note that the design details of the scrubber were not available at the time of our review and no guarantees are being offered for the actual NH3 removal efficiency in the scrubber.

At the "mean" inlet NOx level of 0.24 lb/MMBtu, chemical utilization is slightly better but the controlled NOx for the 10 ppmv slip design case is still 0.18 lb/MMBtu. At 25 ppmv slip, controlled NOx for the mean inlet NOx is projected to be at or below 0.14 lb/MMBtu.

Hopefully this letter summarizes the depth of the review we have conducted for this application and the number of process conditions that must be taken into account prior to establishing SNCR NOx control performance. Fuel Tech, Inc. stands by this analysis based on the design information provided and we would be pleased to discuss our analysis with any of the involved parties.

Design Performance Projections

Expected NOx Baseline, 10 ppmv Ammonia Slip (average, as measured)										
Type of Fuel		Design H2O Bagasse	Design H2O Bagasse	Low H2O Bagasse	Avg. H2O Bagasse	High H2O Bagasse	High H2O Bagasse	Light Fuel Oil	LFO and Bagasse	LFO and Bagasse
Load Case		Series 1	Series 2	Series 3	Series 4	Series 5	Series 6	Series 7	Series 8	Series 9
Gross Heat Input	MMBtu/hr	886.2	424.3	804.5	843.9	844.5	920.0	359.2	894.8	402.8
Baseline NOx	lb/hr	212.7	101.8	192.7	202.4	202.7	220.9	71.8	214.5	96.6
Baseline NOx	lb/MMBtu	0.28	0.28	0.28	0.28	0.28	0.28	0.20	0.28	0.28
Target NOx	lb/MMBtu	0.18	0.16	0.19	0.18	0.17	0.18	0.14	0.17	0.16
Reduction	%	27.5	32.5	25	27.5	30	27.5	30	30	32.5
Average NH3 Slip	ppmv	10	10	10	10	10	10	10	10	10
Expected Temperature at Injectors	F	1850-1950	1650-1750	1925-2025	1875-1975	1800-1900	1825-1925	1600-1700	1725-1825	1600-1700
Furnace CO Limit, Max Entering SH	ppm	400	400	400	400	400	400	200	400	400
NOxOUT-A	gph	32	19	28	30	33	33	12	37	18

DNT

DE-NOX TECHNOLOGIES

De-NOx Technologies, LLC
22 Partridge Lane
East Hampstead, NH 03826
(603) 974-1411
(815) 301-8450 E-fax
dwojichowski@de-nox.com
www.de-nox.com

July 2, 2003

Mr. Mike Cantrell, PE
McBurney Corp
1650 International Court
Norcross, GA 30093

Dear Mr. Cantrell,

SUBJECT:US SUGAR CLEWISTON SNCR PROPOSAL

Per your request, enclosed is a Budget Proposal to design, supply, and start-up the SNCR system for Boiler 8 at the Clewiston Mill.

Please call me if you have any questions.

Sincerely,

David Wojichowski, P.E.
President

DNT

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UNITED STATES SUGAR COMPANY
SNCR DESIGN SUPPLY PROPOSAL
EXECUTIVE SUMMARY

McBurney Corp has requested a budget quote for the design, supply, and start-up of one urea-based SNCR system for US Sugar's new 500,000 pph bagasse boiler in Clewiston, FL. Based upon the information provided, the bagasse boiler (much like wood or refuse) is an ideal candidates for SNCR since it has a generous furnace design and relatively low temperature entering the superheater. As such, the proposed system is guaranteed to provide 50 % NOX reduction, from 0.24 to 0.12 lb/MMBTU with an ammonia slip less than 15 ppmdv at 7%O2. The guarantee is predicated upon the existence of continuous emission monitoring for NOX with time averaging no more stringent than rolling 24 hour averages.

The challenge for the design is to accommodate the entire range of firing conditions – 100% load wet fuel, 100% load dry fuel, 50% load wet fuel, and auxiallary fuel firing. Further, the design must accommodate this operating envelope with a minimum of operator intervention while keeping the system simple and cost effective. To do so, the design allows for 3 injection zones, all automatically selected and operated from the local PLC controller. The lowest zone in furnace elevation is provided for low load on bagasse, the middle zone for high load on bagasse, and the highest zone for auxially fuel firing. Based upon the information provided in the Specification, the only question seems to be the location and performance of the injectors for the liquid fuel-only case.

Several documents are included with this proposal to provide support:
1. DNT Specification 0926 Rev1
2. DNT PID drawing M01
3. DNT drawing Detail 1, showing one form of nozzle penetration
4. DNT drawing Detail 2, showing one other form of nozzle penetration
5. DNT drawing M02, showing a bulk urea storage footprint
6. DNT Project References
7. Colonial Chemical Reagent Price Estimate

PRICING

Engineering $75,600

Urea Supply $328,500
ESTIMATED for first year, calculated as 1000 GPD at $0.90/gal, delivered. Note: Urea is an international commodity chemical whose price is usually adjusted quarterly

or sooner. This estimate reflects current conditions, which tend to be on the high side of historical trends.

Bulk Storage/Control Mod $126,000

Includes the Storage Tank, and adjacent Control Module (incl. Control Panel)

Distr Panels/Injectors $147,000

Includes the Distribution Panels and the Injector Assemblies

Control Panel $38,000

Also included in Control Module Price.

Commissioning/Start-Up/Training $18,640

Firm price based upon two weeks on-site assistance for installation check-out, start-up supervision, performance optimization, and operator training. Calculated as $1000 per day, plus expenses.

Shipping/delivery $10,000

Estimated total shipping charge for all materials, mostly from New England, to site.

Spare Parts $10,000

Estimated Spare Parts for start-up and first year of operation. Mostly spare injection lances, fuses/bulbs, and pump rebuild kits.

Total ?

TECHNICAL SCHEDULE – Case 1 only provided at this time.

		Loadcase Series								
Description	**Units**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Nominal Steam Flow	% MCR	100	50	100	100	93	100	50	100	50
Urea consumption (in as delivered concentration)	gph	**42.9**								
Dilution water consumption	gpm	**1.33**								
Additional heat load	MMBtu	**By Others**								
Increase in furnace mass gas flow	lb/hr	**1063**								
Furnace exit gas temp. drop	°F	**By Others**								
% Nox reduction	%	**50**								
Controlled Nox at boiler outlet	lb/MMBtu	**0.12**								
Ammonia slip	ppmv	**15**								

UNITED STATES SUGAR COMPANY
SNCR SYSTEM
DNT SPECIFICATION NO 0926 – Rev 1

TABLE OF CONTENTS

1.0 INTENT

This specification covers the basic requirements for a urea based SNCR System to be designed and supplied for the US Sugar facility at Clewiston, FL.

1.0 REFERENCED STANDARDS

1.1 Reference to the standards of any technical society, organization, or association, or of the laws, ordinances, or codes of governmental authorities shall mean the latest standard code, or specification adopted, published, and effective on the date of the purchase order unless specifically stated otherwise in the contract documents.

1.2 The specifications, codes, and standards referenced below shall govern in all cases where references thereto are made. In case of conflicts between the referenced specifications, codes or standards and these specifications, the latter shall govern to the extent of such differences.

AGMA	American Gear Manufacturer's Association
AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
AWS	American Welding Society
IEEE	Institute of Electrical and Electronics Engineers
ISA	Instrument Society of America
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NESC	National Electrical Safety Code
SSPC	Steel Structures Painting Council
NFPA	National Fire Protection Association

2.0 DEFINITIONS

2.1 For the purpose of this Specification, the following definitions and abbreviations shall apply:

2.2 Purchaser: McBurney Boiler Company.

2.3 Vendor: De-NOx Technologies, 22 Partridge Lane, East Hampstead, NH 03826

2.4 Contract: A purchase order placed by the Purchaser with DNT, together with Specifications and all other documents referred to in such purchase order.

2.5 Work: Labor, supervision, services, materials, supplies, machinery, equipment, tools, and facilities called for by the Contract.

2.6 Approved Equal: Products that are considered equal only upon receipt of the Purchaser's written approval.

3.0 GENERAL REQUIREMENTS

3.1 The work on this Contract shall commence after DNT has received written Notice to Proceed from the Purchaser. The work shall be executed with sufficient personnel, equipment and material for as many hours per shift and shifts per week as may be required to complete the work in the time stated herein or in the purchase order.

3.2 All Drawings and Documents pertaining to the work shall remain the sole property of DNT and shall not be disclosed by the Purchaser to any third party without prior approval of DNT. Purchaser may provide additional drawings and information to DNT for the purposes of providing additional information, clarifying information already supplied or revising information as required. All such revised and/or additional information is not intended to constitute a change in DNT's Scope of Work, unless it is so designated and so deemed a change in Scope by both the Purchaser and DNT.

3.3 DNT shall furnish the interface details for all electrical, mechanical, and structural interfaces between DNT's Equipment and Purchaser's System. These details shall include as applicable but not necessarily be limited to; physical size, weight, shape, foundation loads, electrical voltage, current, phase(s) and frequency, as well as control interlocks and alarms. DNT shall assist the Purchaser, as required, with the integration of DNT's equipment into the Purchaser's system.

4.0 DESIGN CONDITIONS

This system is to be installed on one new 886 MMBTU/hr bagasse fired boiler at Clewiston, FL. The proposed system will utilize 50 wt% liquid urea.

The major design parameters are presented in Table 1.

TABLE 1
Design Conditions per Combustion Unit

Design Parameters	Typical
Combustor Capacity (MMBTU/hr)	1 x 886
Oxygen Level (% v)	3-7
Carbon Dioxide (% v)	13-19
Carbon Monoxide (ppmdv 3%)	LT 400
Approx Injection Temp (deg F)	1,800 – 1,950
Min ResidenceTime (sec, prior to	0.5
first convective surface)	
Design Minimum Boiler Load	50%
Uncontrolled NO_x (lb/MMBTU)	0.24
Controlled NO_x (lb/MMBTU)	0.12
Ammonia Slip (ppmdv @ 7% O_2)	10

5.0 SCOPE OF SUPPLY

DNT will provide the following equipment for the Clewiston facility:

Equipment

- One (1) 15,000 gallon FRP Storage Tank. Based on the information provided and the calculations, this tank will provide a storage capacity of 14 days for the facility operating at 100% load. The approximate dimensions of the tank will be 12' diameter and 18' straight side. The approximate weight of the empty tank will be 4,000 lbs.

  Because of the subtropical nature of the Site, significant capital cost and operational advantages are realized by the elimination of concentrated reagent heating/insulation. If 40 wt% urea solution is used, there will be no risk of crystallization – even well below the ASHRAE 99% dry bulb minimum winter design temperature of 41F. There is a minor operational cost disadvantage hauling extra water to the Site (presumably from the Tampa area), estimated to be approx $15,000 per year. This disadvantage, however, can be eliminated or minimized by purchasing 50 wt% solution during the majority of the year or all year AND on-site dilution when delivered. The storage tank will be filled from 5000 gallon tanker trucks.

The storage tank will also be supplied with:

- Top bolted man way
- Gusseted flanged fittings made of FRP for outlet, fill and instruments.
- Hold Down and Lifting Lugs
- Gooseneck Vent, Drain, Fill Connection, and External Fill Line
- Carbon Steel Ladder, Cage and Handrail, painted safety yellow
- Outlet, Level Indicator, and Drain Isolation Valves
- Level Indicating Transmitter
- Temperature Indicating Transmitter
- Top non-slip surface and UV gel coat protection

- One SNCR Control Module will be supplied. This module will filter and regulate the flow of concentrated reagent and dilution water and mix the two together. The module will be pre-assembled. The Control Module will be located outdoors immediately adjacent to the storage tank. The size of this module is approximately 4' x 6'.

  The module will be equipped with two (2) variable speed, hydraulically actuated, diaphragm pumps (Neptune Series 500 or equal) one operating and one standby. All wetted materials will be constructed of 316 Stainless Steel. The pumps will be equipped with Viton tubular diaphragms. The units will also come equipped with manual stroke adjustment.

  Two (2) duplex strainers of 316 SS construction, capable of continuous filtering of the concentrated reagent and dilution water shall be provided. The device shall be capable of being maintained while on line. Filtering elements shall be constructed of 40 mesh stainless steel screen.

  One local stainless steel NEMA 4X panel will be provided and will include main disconnect, 120 VAC starters, A/B PLC, PLC Power Supply, AI/AO/DI/DO modules, color touch screen HMI, SCR/DC controllers, fuses, motor protectors, panel-front pilot lights/HOA switches, and DH+ interface with the plant's central DCS system. The system shall be capable of full manual operation in case of PLC failure. The Central Control Station shall be capable of monitoring operating parameters and alarm status, as well as remote start/stop. The module's components will be pre-wired and pre-assembled.

The proper amount of reagent is determined based upon boiler load and from CEM system feedback. The metered urea will be introduced into the dilution water line and thoroughly mixed via a SS in-line static mixer. Materials of construction for the concentrated reagent and diluted reagent lines shall be 304 SS tubing, socket welded connections to the maximum extent possible.

- Distribution Panels. Five Distribution Panels shall be provided, located in the closest reasonable proximity to the injection nozzles, each capable of accommodating six injectors. These panels distribute diluted reagent to each injector, as well as control air pressure. Each injector will have local reagent sight flow indication to balance/bias active injectors. These panels can be mounted above handrails of wrap-around platforms, or any convenient wall or column. They measure approximately 3'H x 5W' and weigh less than 500 lbs. From these panels, individual liquid lines are run to each injector.

  The compressed air and liquid flow to each Panel is controlled by MOV's which receive respective signals from the Control Module PLC. The air MOV is provided with a restriction orifice bypass to provide cooling air to idle injectors.

- Dual Fluid Nozzle Atomizing Injectors. The injectors mix the diluted reagent and the atomizing air in the nozzle body outside the boiler. The two-phase fluid then travel down a single, heavy wall, high-alloy tube, terminating 4 - 6 inches inside the boiler. The proprietary injectors have particular advantages:
  - Excellent service life – probably 12 months or better in a bagasse boiler.
  - Non-plugging operation with low quality dilution water
  - Quick connect cam-lock fittings to the boiler mounting tubes, swage-lok fittings to the flexible hose connections, and quick compression-type fittings for easy lance replacement.
  - Short extension outside of the boiler cladding – they can be located in more congested areas.
  - No need for waterwall modifications – can be mounted within a web space as low as ½".

Three separate injection zones are expected based upon the furnace temperature profiles provided in the Request for Proposals. The 100%

load case will be serviced by 6 front wall and 6 rear wall injectors located at elevation 630 inch (above basement) or elev 440 inch above top of grate. The 50 % load case (no aux fuel) will be addressed by a similar zone located at elev 500 inch above basement (306 inch above top of grate), which was selected to be co-located and concentric with the tertiary OFA nozzles. The advantage of integrating the two would be: 1) fewer boiler ports,2) automatic lance cooling when out of service and 3) better furnace penetration/mixing. The third zone would service the LFO case and will be above the 100% load zone, front wall only.

Detail 2 is typical of nozzle penetrations for the wall injectors, detail 1 is a sketch of a proposed arrangement for the zone integrated with the tertiary air system.

Flexible hoses, attached to the injectors with quick connects, will be supplied. The flexible hoses allow for easy removal from the injection port for inspection and maintenance.

Engineering and Start-up Services. These services would include:

- P&ID's, Equipment Arrangement Drawings, mechanical fabrication and assembly drawings, electrical schematic drawings, panel layout, PLC/HMI programming, and bill of materials.
- Specify, select, purchase, prefabricate, and deliver the necessary equipment.
- Civil, Mechanical, and Electrical installation specs
- Mechanical checkout and start-up
- System Optimization.
- Five Maintenance and Operation Manuals.

6.0 PROVIDED BY CUSTOMER

- All receiving and installation.

- Approximately 5 GPM of dilution water @ 80 psig to the Control Module. The quality of the dilution water should meet the following guidelines :

Temperature	50 °F (min)
pH	6-8
Total dissolved solids	500 ppm (max)
Total Hardness as $CaCO_3$	200 ppm (max)
Total suspended solids	10 ppm (max)
Chlorides	50 ppm (max)

- Compressed Air Supply – Normal 150 scfm, design 300 scfm, nominal 100 psig.

- Fused disconnect for 120 VAC power to the Control Module.

- All local permits and/or licenses. DNT will support customer's permitting effort with engineering drawings – stamped by a FL registered PE if necessary.
- Compliance Testing (assumed to be combined with Performance Testing).

- Hardware/Software interface to Central Control, any additions to Central Control hardware, and Central Control graphics/configuration.

- Adequate trenches, sumps, and drains

- A CEM system capable of measuring NOx, O2, and CO and which meets State and EPA RATA criteria.

- Infrared Furnace Temperature instrument with output to control module PLC.

- Any additional platforms, if any, needed to access the new equipment

7.0 PROJECT SCHEDULE

Begin Equipment Design	At Notice to Proceed
Complete Equipment Design	10 weeks after NTP

Complete delivery of equipment	16 weeks after Approvals
Typical Mech and Elec Installation	6-8 weeks after mobilization

8.0 PERFORMANCE GUARANTEE

8.1 Guarantees

When operating within the design criteria set forth in Table I, DNT guarantees that the outlet NO_x emissions will not exceed 0.12 lbs/MMBTU heat input or 50% reduction, whichever is least stringent. This guarantee will be demonstrated in a Performance Test to be scheduled within 90 days after the equipment is ready for initial operation and testing as determined by DNT. The duration of the Performance Guarantees set forth above shall be for 12 months after successful completion of the Performance Test; 15 months after start up of the equipment; 18 months after substantial completion of erection; or 21 months after substantial completion of delivery, whichever comes first. If such field performance test is not completed within the previously specified 90 day period, through no fault of the Seller, and Purchaser has received from Seller written notice thereof, the Equipment shall conclusively be deemed to meet the stated Performance Guarantee(s). In the event that the operating conditions vary from the Design Conditions given in Table I, the guarantees set forth herein affected by such changed conditions shall be subject to modification and, if the parties mutually agree in writing, the guarantees herein may be appropriately revised.

8.2 <u>Performance Test</u>

- Nitrogen Oxides

  The maximum outlet emission level will be demonstrated by use of the Continuous Emission Monitor by calculating a 24-hour average over a three (3) day time period. Compliance with the guarantee shall be based on the arithmetic average of the hourly emission concentration measured with the CEM system during each day of the three (3) day period, between midnight and the following midnight. The operation of the unit to be tested will be held constant for at least two (2) hours prior to the Performance Test and be at or near the design conditions given in Table 1 throughout the test period. The CEM installation, evaluation and operation shall follow the procedures set forth in 40 CFR 60.13 and shall be operated according to Performance Specification 2 in 40 CFR 60, Appendix B.

- Steady State Conditions

  All testing shall be conducted only at steady state conditions. The boiler and equipment must be at steady state a minimum of two hours prior to testing. Steady state is defined as conditions where flue gas flow rates and temperatures from the boiler do not vary more than +/- 5% and are within design conditions as identified in Table I.

8.3 Guarantee Provisions

The guarantee(s) set forth herein is (are) subject to the following provisions:

- The Equipment supplied by DNT shall be operated and maintained according to DNT's guidelines, good engineering and operating principles and DNT's Operating and Maintenance Manual.

- DNT reserves the right to inspect the Equipment to determine that the operation has been in accordance with DNT's Maintenance and Operation Manual. If required by DNT, the Purchaser will restore the Equipment to good operating conditions before any Performance Tests are conducted.

- DNT will have access to any test records at all times and will have the cooperation of the Purchaser in conducting any preliminary tests that DNT may deem necessary.

- As soon as possible after installation, DNT shall be permitted to conduct preparational tests, at his option, and make adjustments as is necessary to assure that the Performance Guarantee can be fulfilled.

9.0 INSTRUMENTATION:

9.1.1 DNT shall furnish all instrumentation and switches required to monitor and control the System as required in this specification and as indicated on the P&ID's.

9.1.2 All instruments shall be factory calibrated and set. Calibration and testing records shall be furnished for all instruments.

9.1.3 DNT shall tag all instrumentation with Purchaser's tag numbers. Instrument numbers will be provided on P&ID's .

9.1.4 DNT shall provide instrument index, listing instrument tag number, description, manufacturer and model number for all instruments. List shall also be provided which indicates the calibrated range of instruments and set points for all switches.

9.1.5 All level transmitters shall be differential pressure type

9.1.6 All instruments to receive manufacture's standard finish paint.

10.0 EQUIPMENT SURVEILLANCE AND TESTING

10.1 All equipment furnished on the purchase order, including auxiliaries, shall be subject to inspection by the Purchaser's and/or Owner's inspection representative. Purchaser's and/or Owner's representative shall be allowed entry into the plant facilities of the manufacturer and its subDNTs and have access to drawings, schedules, inspection reports, material specifications, and tests pertaining to the equipment being furnished on the purchase order.

10.2 Quality Standards and Control shall meet the requirements specified by the Purchase Order.

10.3 PAINTING. CS items will be prepped in accordance with SSPC-6, 3 mil zinc oxide primer, and 3 mil finish coat.

10.4 Specialty items such as motors and variable speed control units, if furnished with the equipment, shall be painted in the shop in accordance with manufacturer's standard practice.

10.5 Before painting, all parts of the equipment shall be thoroughly cleaned of all mill scale, rust, grease, and other foreign matter. All exposed unfinished surfaces of castings shall be properly filled. All welded surfaces shall first be thoroughly cleaned of all alkaline scale, or other deleterious materials that would affect the paint.

10.6 Surfaces shall be thoroughly dry at the time of paint application.

10.7 Chipped, cracked, peeled, or defective paint except where mechanically damaged during shipment, unloading, or erection, shall be replaced at DNT's expense.

11.0 SPARE PARTS

DNT shall provide upon completion of design activities, as a separate line item, the spare parts for the equipment required for one year of operation. Spare parts shall be tagged as "Spare Parts" and shipped separate from the equipment. Spare parts supplied shall be suitably wrapped or packaged and tagged with DNT's Part Number.

12.0 DRAWINGS AND DOCUMENTS

12.1 General arrangement drawings, including an equipment outline drawing shall show all dimensions, clearances, interfaces, tolerances, foundation loading, anchor bolt requirements, etc.

12.2 All electrical interconnection and wiring diagrams of the equipment, including all variable speed drives (where applicable), control panels, and switches that are furnished with the equipment.

12.3 All drawings shall be clear and legible. Drawings shall be a maximum of 24" X 36" (Size "D" per ANSI 14.1) and shall be to scale where applicable. Equipment general arrangement drawings shall be furnished as CAD drawings in Microstation, or Autocad.

12.4 All words and dimensional units shall be in the English language.

13.0 SUBMITTALS

13.1 Drawings and data sheets shall be stamped and returned to DNT as follows:

13.2 APPROVED: Drawings and documents not requiring corrections.

13.3 APPROVED AS NOTED: Drawings and documents shall be corrected and resubmitted immediately as many times as necessary until approved.

13.4 NOT APPROVED: Drawings shall be immediately corrected and resubmitted for approval.

13.5 Equipment shall not be fabricated or delivered prior to DNT receiving approval of drawings/documents from Purchaser unless such approval has been waived in writing.

13.6 All drawings revised after initial submittal, shall be resubmitted with the revised area clearly indicated and revision number and date listed in the title block.

13.7 Identification: All Drawings and Documents transmitted by DNT shall be marked and identified as follows:

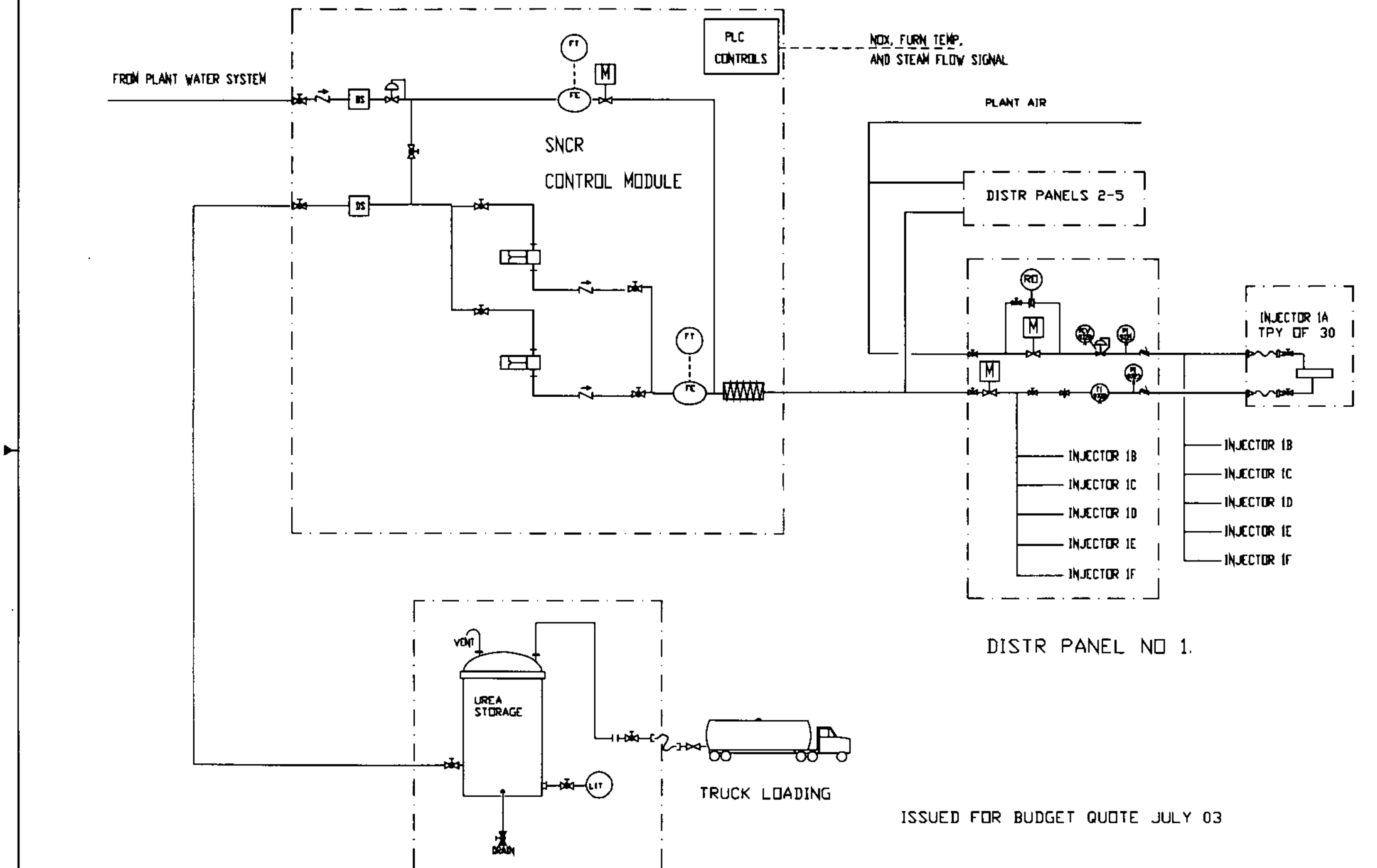
DNT Contract Number (Later)
DNT Specification SPEC-0927
Service: SNCR System
Equipment No.: (Later)

13.8 Mail all Drawings, Data Sheets and Documents with a letter of transmittal to the following address:

Later
Attention: Purchasing Department

13.9 Drawing/Document Transmittal Letter to show the following:

Project Name
DNT Contract Number: Later
DNT's Drawing Number and Title:
Revised Drawings Shall be so Marked and Dated

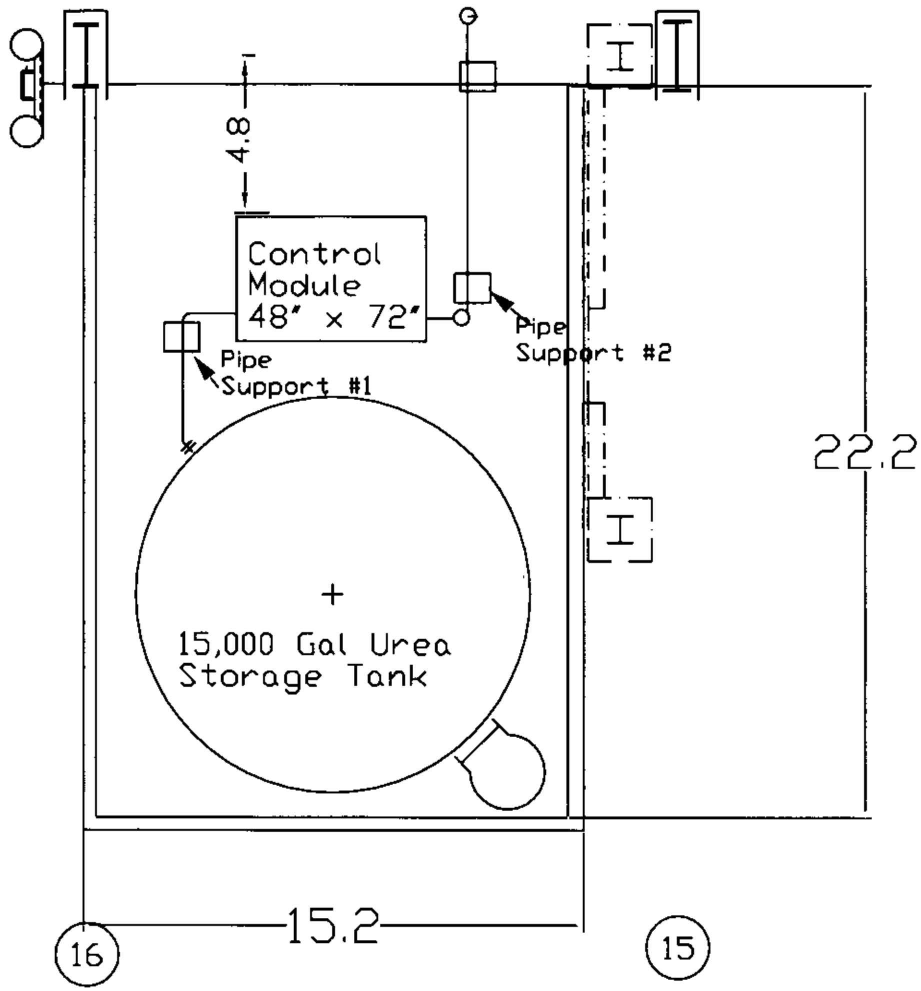


ISSUED FOR BUDGET QUOTE JULY 03

SNCR SYSTEM
US SUGAR COMPANY
PRELIMINARY P&ID

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

M 01
0

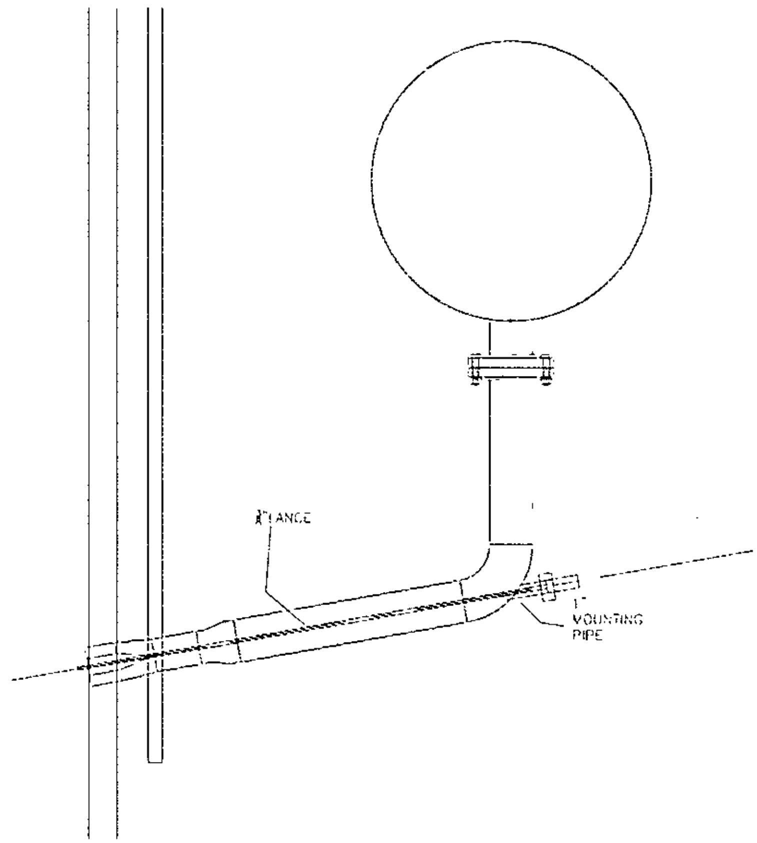


US SUGAR CO
SNCR PROPOSAL

LAYOUT

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

DNT M02 0

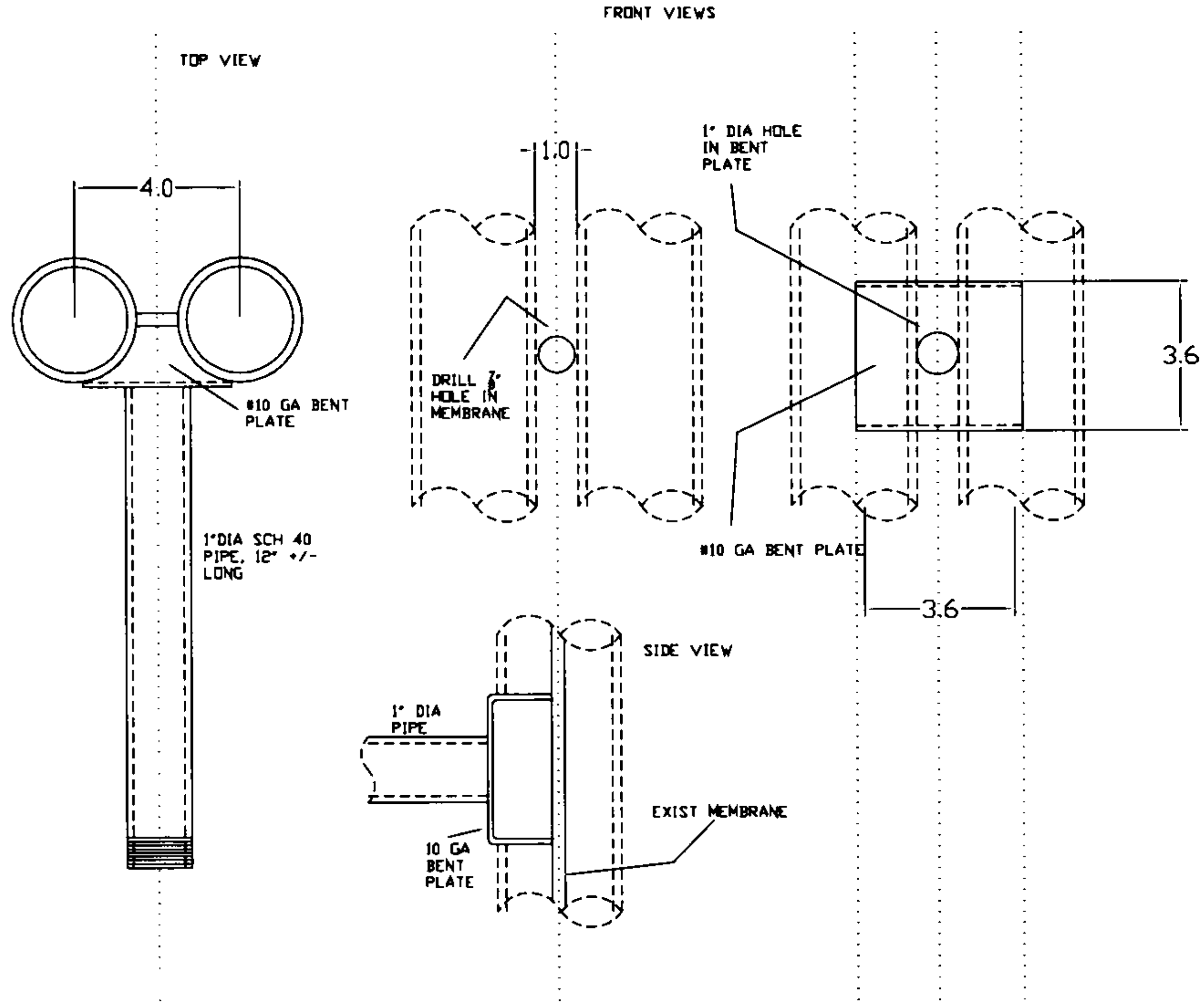


SNCR SYSTEM
US SUGAR COMPANY
INJECTION PORTS

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

DETAIL 1

0



US SUGAR
SNCR SYSTEM

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

INJECTION PORTS

DETAIL 2 0

COLONIAL
CHEMICAL
COMPANY
A Unit of The ESS Group, Inc.
Corrosive Liquids
Formulated & Packaged

July 1, 2003

Mr. David Wojichowski
Managing Director
De Nox Technologies
22 Partridge Lane
East Hampstead, NH 03826

Transmitted by fax - #(815) 301-8450

Dear Dave:

Regarding your request for a forecast of urea costs (40%) to be available in summer of 2004. I would suggest the following price range.

40% liquid urea delivered southeastern Florida region - 1,000 gallon usage/day. {Assuming reasonable stability in the natural gas market ($5 - $6 / MMBTU)}, the average price for 40% liquid would be $.85 - $.95/gallon.

If you have any further questions, please advise.

Very truly yours,

Jim Egan

James T. Egan
President

JTE:kr

78 Carranza Road
Tabernacle, NJ 08088

Tel 609.268.1200
Fax 609.268.2117

DNT

DE-NOX TECHNOLOGIES

De-NOx Technologies, LLC
22 Partridge Lane
East Hampstead, NH 03826
(603) 974-1411
(815) 301-8450 E-fax
dwojichowski@de-nox.com

DE-NOX PROJECT REFERENCES

Frackville Dry SNCR Project – Frackville, PA
Scope: Voluntary installation of DNT's proprietary dry SNCR system on a 42 MW Circulating Fluid Bed coal fired boiler. First-of-its-kind installation, designed to generate excess SIP-Call NOX Allowances for profit. Several advantages: 1) Lowest possible capital, 2) Near-negligible chemical costs, 3) No boiler heat rate penalty, and 4) Elimination of boiler tube corrosion risk.

Temple Inland Forest Products – Clarion, PA
Scope: SNCR Optimization Study. Evaluate existing urea SNCR system operation on a wood-fired bubbling bed combustor. Troubleshoot problems and recommend upgrades. Combustor experienced frequent plugging of OEM injectors and marginal NOX reduction. Situation remedied by the supply of new injectors, with superior atomization, and non-clogging internals. Unit operating well with half the number of injectors, longer service life, zero secondary water dilution, and no clogging.

Lihue Energy Services Project – Kauai, Hawaii.
Customer: Innovative Steam Technologies, Cambridge, Ontario
Scope: Design and Supply of a Dry Urea Handling System which creates a urea solution from dry prill delivered in Supersacks for use in a NOX reduction system. Fully shop prefabricated with PLC controls. Accelerated schedule with commercial guarantees.

Martell Cogeneration Facility – Martell, CA
Scope: Process Optimization and equipment upgrades for an existing SNCR system at this 15MW wood fired unit. Unit demonstrated a detached stack plume from excess ammonia slip. Included furnace temperature profiling, dual fluid nozzle supply, and an atomizing air distribution system.

Gloucester County Resource Recovery Facility – Westville, NJ – late 200 and early 2001
Scope: Project Engineer and General Contractor for the installation of an SNCR system and Continuous Emission Monitoring System upgrade. Included the expansion of the compressed air system and the supply of dual fluid injection nozzles to replace the OEM equipment. New nozzles showing much greater service life and 25-30% lower reagent consumption. Design improvements also expected to reduce/eliminate localized corrosion to boiler tubes.

South Broward Resource Recovery Facility – Ft Lauderdale, FL – mid 2000.

Scope: Project Engineer and General Contractor for the installation of an SNCR system at this 90MW refuse to energy facility. Design activities: civil, mechanical, electrical, compressed air addition. Installation activities: bid package development, contractor selection, and construction management.

North Broward Resource Recovery Facility – Pompano Beach, FL – mid 2000

Scope: Same as for South Broward – work nearly identical and executed simultaneously.

Baltimore RESCO – Baltimore, MD - 1999

Scope: Lead Project Engineer and Engineer-of-Record for a large ($40 MM) air pollution control retrofit project, which included expansion of their existing SNCR system.

Westchester RESCO – Peekskill, NY – 1998

Scope: Lead Project Engineer and Engineer-of-Record for a large ($68 MM) air pollution control retrofit project, which included a new SNCR system.

Ridge Generating Station – Lakeland, FL

Scope: Tested generic urea reagents as a substitute for the more expensive, proprietary, reagent. Test was successful leading to a similar conversion at 11 other facilities.

Shasta Energy – Anderson, CA 1989

Scope: Project Engineer for the design and installation of an SNCR system at this 60MW wood fired plant.

Wheelabrator Millbury – Millbury, MA 1986

Scope: Project Engineer for the design, installation, and testing of an SNCR system at this 45MW refuse to energy facility. This was a temporary demo project to test the performance of the system prior to installation elsewhere with commercial and regulatory guarantees. This was the first installation at a large municipal waste-to-energy facility in the US.

DE-NOX PATENT ASSETS

Three separate US Patent Applications Pending. Technologies address Dry SNCR Processes for several combustion types, external urea-to-ammonia process for SCR reagent supply, and retrofit of existing urea-to-ammonia systems.

ATTACHMENT B

REVISIONS TO PERMIT APPLICATION FORM AND PSD REPORT

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Electrostatic Precipitator** **Wet Sand Separator** **Selective Non-Catalytic Reduction for NO_x**
2. Control Device or Method Code(s): **010, 099, 107**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating:	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **288.4** lb/hour **473.7** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.14 lb/MMBtu (average)** Reference:	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Maximum hourly rate: 1,030 MMBtu/hr x 0.28 lb/MMBtu = 288.4 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 473.7 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential emissions representative of bagasse firing. Maximum hourly based on no reduction from SNCR system.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.14 lb/MMBtu, 12 month**	4. Equivalent Allowable Emissions: **288.4** lb/hour **473.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Proposed BACT limit. Emissions representative of bagasse firing only.**	

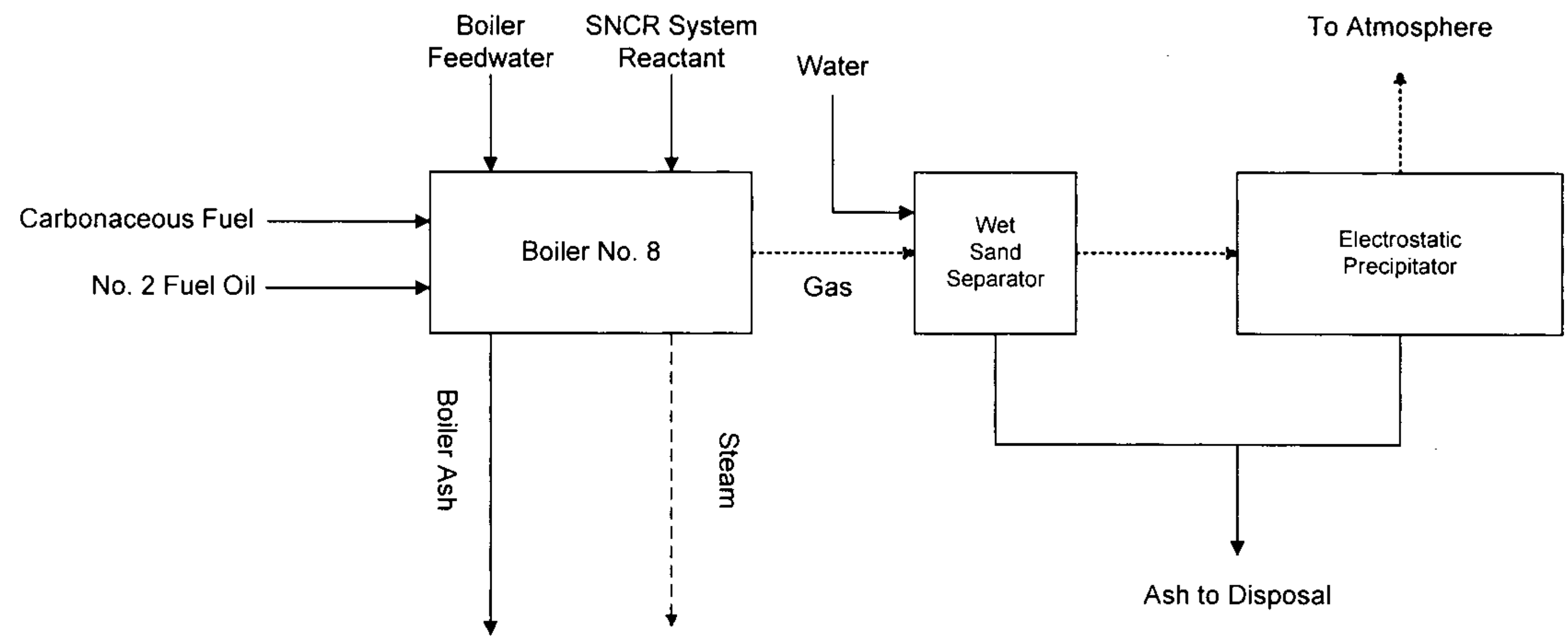
G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.14 lb/MMBtu**	4. Equivalent Allowable Emissions: **157.36** lb/hour **57.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 7 or 7E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Proposed BACT limit. Emissions representative of No. 2 fuel oil firing only. Maximum hourly based on 0.28 lb/MMBtu. Annual emissions based on proposed limit of 6,073,600 gal/yr.**	



Attachment UC-EU1-J1
Process Flow Diagram
U.S. Sugar Corporation
Clewiston Mill, Florida

Process Flow Legend
Solid/Liquid ———→
Gaseous ·········→
Steam - - - - - -→

Project Number: 0237619\4\4.1\L071803
Filename: UC-EU1-J1.VSD
Date: 7/18/03

Golder Associates

Table 2-2. Maximum Short-Term Emissions for Boiler No. 8, U. S. Sugar Clewiston

Regulated Pollutant	Bagasse				No. 2 Fuel Oil				Natural Gas				Maximum Emissions for any fuel (lb/hr)
	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	
Particulate (Total/PM_{10})													
--3-hr Average	0.026	(1)	1,030	26.8	0.026	(1)	562	14.61	0.0076	(8)	562	4.27	26.8
--24-hr Average	0.026	(1)	936	24.3									24.3
Sulfur Dioxide													
--3-hr Average	0.17	(2)	1,030	175.1	0.05	(7)	562	28.10	0.006	(8)	562	3.37	175.1
--24-hr Average	0.10	(2)	936	93.6	--		--	--	--		--	--	93.6
Nitrogen Oxides													
--3-hr Average	0.28	(3)	1,030	288.4	0.28	(3)	562	157.36	0.28	(3)	562	157.36	288.4
--24-hr Average	0.28	(3)	936	262.08	--		--	--	--		--	--	262.08
Carbon Monoxide													
--1-hr Maximum	6.5	(4)	1,030	6,695.0	0.036	(10)	562	20.2	0.084	(8)	562	47.208	6,695.0
--8-hr Maximum	4.5	(4)	1,030	4,635.0	--		--	--	--		--	--	4,635.0
VOC	0.06	(3)	1,030	61.8	0.0014	(10)	562	0.79	0.0055	(8)	562	3.09	61.80
Sulfuric Acid Mist													
--3-hr Average	0.0104	(5)	1,030	10.72	0.0015	(5)	562	0.8430	3.68E-04	(5)	562	0.21	10.72
--24-hr Average	0.0061	(5)	936	5.73	--		--	--	--		--	--	5.73
Lead	3.8E-05	(6)	1,030	0.039	9.0E-06	(10)	562	5.1E-03	5.0E-07	(8)	562	2.8E-04	0.039
Mercury	1.4E-05	(6)	1,030	0.0144	3.0E-06	(10)	562	1.7E-03	2.6E-07	(8)	562	1.5E-04	0.0144
Fluorides	6.0E-04 (7)		1,030	0.618	--		--	--	--		--	--	0.62

References:

1. Proposed BACT limit.
2. 3-hr avg. based on permit limit for Boiler No.7. The 24-hr avg. is based on stack test data for Boiler No 7
3. Based on Boiler No. 7 test data.
4. Represents startup or wet fuel conditions
5. Based on the SO_2 emission factor and a 5% of conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Based on worst-case bagasse analysis for Clewiston mill.
7. Based on maximum of stack tests from Okeelanta cogen when burning bagasse only.
8. Based on AP-42 Section 1.4 for natural gas combustion:

PM (total):	7.6 lb/10^6 scf	VOC:	5.5 lb/10^6 scf
SO_2:	0.6 lb/10^6 scf	Mercury:	2.6E-04 lb/10^6 scf
CO:	84 lb/10^6 scf	Lead:	0.0005 lb/10^6 scf

9. Based on use of No. 2 fuel oil with a maximum of 0.05% sulfur.
10. From AP-42, Section 1.3 for fuel oil combustion:

CO:	5 lb/1,000 gal	Mercury:	3 lb/10^{12} Btu
VOC:	0.2 lb/1,000 gal	Lead:	9 lb/10^{12} Btu

Table 2-3. Maximum Annual Emissions for Boiler No. 8, U. S. Sugar Clewiston

Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Ref.	Biomass Activity Factor (MMBtu/yr)	Biomass Annual Emissions (TPY)	Alternate Fuel Emission Factor (lb/MMBtu)	Alternate Fuel Activity Factor (MMBtu/yr)	Alternate Fuel Annual Emissions (TPY)	Total Annual Emissions (TPY)
				100% Bagasse				
Particulate (Total/PM_{10})	0.026		6,767,100	87.97	--	--	--	87.97 [a]
Sulfur dioxide[c]	0.06	(1)	6,767,100	203.01	--	--	--	203.01 [a]
Nitrogen oxides[b]	0.14		6,767,100	473.70	--	--	--	473.70 [a]
Carbon monoxide[b]	0.38	(2)	6,767,100	1,285.75	--	--	--	1,285.75 [a]
VOC	0.06		6,767,100	203.01	--	--	--	203.01 [a]
Sulfuric acid mist	0.0037	(3)	6,767,100	12.43	--	--	--	12.43 [a]
Lead	3.8E-05		6,767,100	0.13	--	--	--	0.13 [a]
Mercury	1.4E-05		6,767,100	0.0474	--	--	--	0.047 [a]
Fluorides	6.0E-04		6,767,100	2.03	--	--	--	2.03 [a]
				90% Bagasse / 10% Fuel Oil				
Particulate (Total/PM_{10})	0.026		5,947,164	77.31	0.026	819,936	10.66	87.97 [a]
Sulfur dioxide[c]	0.06	(1)	5,947,164	178.41	0.05	819,936	20.50	198.91
Nitrogen oxides[b]	0.14		5,947,164	416.30	0.14	819,936	57.40	473.70 [a]
Carbon monoxide[b]	0.38	(2)	5,947,164	1,129.96	0.036	819,936	14.76	1,144.72
VOC	0.06		5,947,164	178.41	0.0014	819,936	0.57	178.99
Sulfuric acid mist	0.0037	(3)	5,947,164	10.93	0.0015	819,936	0.61	11.54
Lead	3.8E-05		5,947,164	0.11	9.0E-06	819,936	0.00	0.12
Mercury	1.4E-05		5,947,164	0.0416	3.0E-06	819,936	0.00	0.0429
Fluorides	6.0E-04		5,947,164	1.78	--	--	--	1.78
				90% Bagasse / 10% Natural Gas				
Particulate (Total/PM_{10})	0.026		5,947,164	77.31	0.0076	819,936	3.12	80.43
Sulfur dioxide[c]	0.06	(1)	5,947,164	178.41	0.006	819,936	2.46	180.87
Nitrogen oxides[b]	0.14		5,947,164	416.30	0.14	819,936	57.40	473.70 [a]
Carbon monoxide[b]	0.38	(2)	5,947,164	1,129.96	0.084	819,936	34.44	1,164.40
VOC	0.06		5,947,164	178.41	0.0055	819,936	2.25	180.67
Sulfuric acid mist	0.0037	(3)	5,947,164	10.93	3.68E-04	819,936	0.15	11.08
Lead	3.8E-05		5,947,164	0.11	5.0E-07	819,936	0.00	0.11
Mercury	1.4E-05		5,947,164	0.0416	2.6E-07	819,936	0.00	0.0417
Fluorides	6.0E-04		5,947,164	1.78	--	--	--	1.78

[a] Denotes maximum annual emissions for any fuel scenario.

[b] Based on 12-month rolling average.

Note: Fuel type percentages are based on heat input.

References:

Unless otherwise note, refer to Table 2-2 for reference.

1. Based on New Hope Power Partnership (Okeelanta Cogen) Permit No. 0990332-014-AC.
2. Equivalent to 363 ppmvd @ 7% O2, as a 12-month rolling average.
3. Based on the SO_2 emission factor and 5% conversion of SO_2 to SO_3 and taking into account the ratio of the molecular weights (98/80).

Table 3-3. Boiler No. 8 PSD Source Applicability Analysis, U. S. Sugar, Clewiston

	Baseline Emissions [a]				Future Potential Emissions				Net Change In		
Regulated Pollutant	Boiler No. 3 (TPY)	Fugitive Emissions[b] (TPY)	Sugar Refinery (TPY)	Total (TPY)	Boiler No. 8 (TPY)	Fugitive Emissions[b] (TPY)	Sugar Refinery (TPY)	Total (TPY)	Emissions Due to Proposed Project (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Triggered?
Particulate Matter (Total)	48.09	2.59	13.20	63.88	87.97	12.93	21.40	122.30	58.42	25	Yes
Particulate Matter (PM_{10})	44.48	1.65	13.06	59.19	87.97	12.07	21.40	121.44	62.25	15	Yes
Sulfur Dioxide	46.81	--	0.75	47.56	203.01	--	1.25	204.26	156.70	40	Yes
Nitrogen Oxides	47.72	--	7.87	55.59	473.70	--	13.14	486.84	431.24	40	Yes
Carbon Monoxide	1,236.31	--	7.87	1,244.18	1,285.75	--	13.14	1,298.89	54.71	100	No
VOC	50.48	--	4.34	54.82	203.01	--	19.38	222.39	167.57	40	Yes
Sulfuric Acid Mist	2.87	--	0.046	2.91	12.43	--	0.077	12.51	9.60	7	Yes
Lead	0.0076	--	--	0.0076	0.13	--	--	0.13	0.12	0.6	No
Mercury	0.0027	--	--	0.0027	0.047	--	--	0.047	0.045	0.1	No
Fluorides	1.20	--	--	1.20	2.03	--	--	2.03	0.83	3	No

[a] Actual emissions based on the average emissions for 2001 and 2002.

[b] Represents emissions from bagasse conveying system. See Attachment UC-EU2-G8 and Appendix G for calculations.

TSP = Total Suspended Particles

PM_{10} = Particulate Matter with aerodynamic diameter less than or equal to 10 microns

VOC = Volatile Organic Compounds

ATTACHMENT C

REVISIONS TO AIR MODELING ANALYSIS

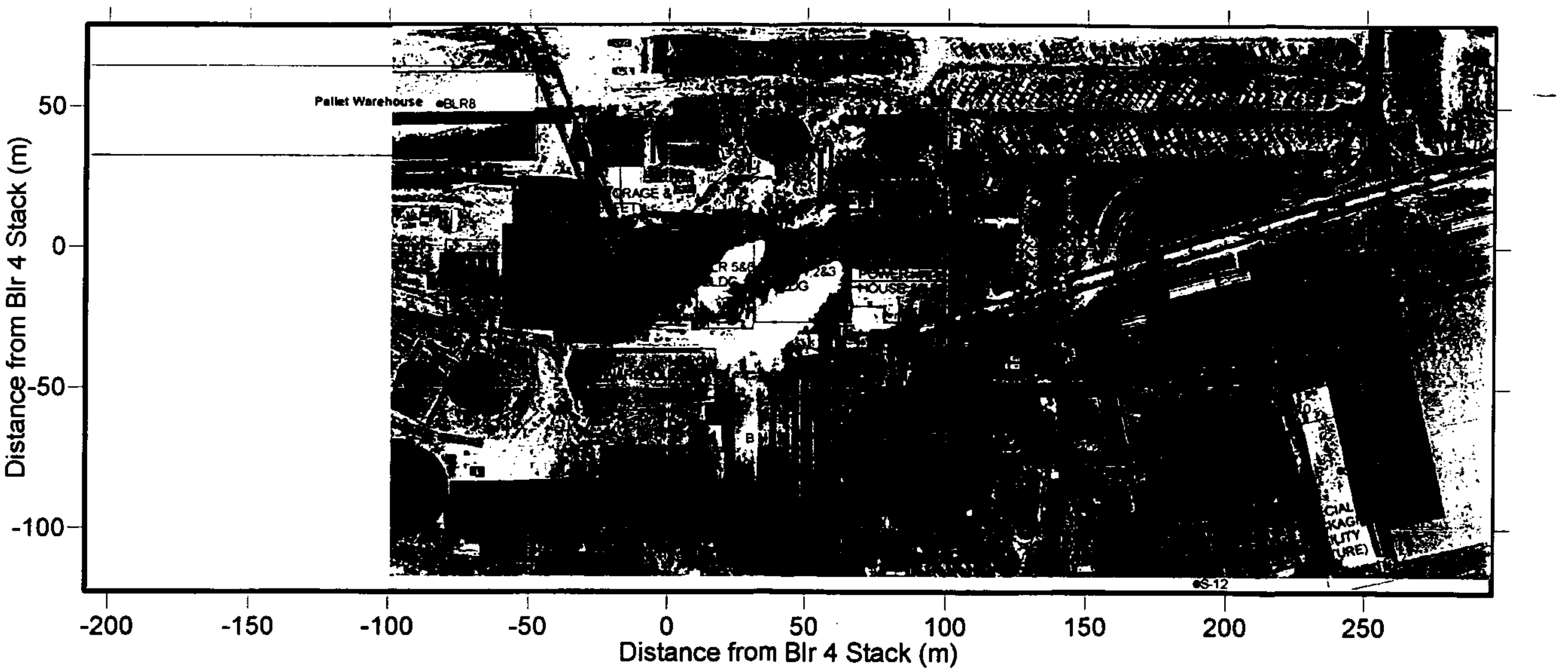

Pallet Warehouse
BLR8
S-12
50
0
-50
-100
Distance from Blr 4 Stack (m)
-200
-150
-100
-50
0
50
100
150
200
250
Distance from Blr 4 Stack (m)

Table 6-6. Maximum Pollutant Impacts Predicted for the Proposed Project in the Clewiston Mill Vicinity-Screening Analysis with Proposed Boiler No. 8 at 100 Percent Load (Revised July 21, 2003)

Pollutant	Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2	Annual	0.08	300	5,000	87123124
		0.07	300	5,000	88123124
		0.08	300	5,000	89123124
		0.09	300	5,000	90123124
		0.07	300	5,000	91123124
	24-Hour	1.57	300	7,000	87062024
		1.65	260	2,000	88061824
		1.45	330	4,000	89060924
		1.94	320	4,000	90101024
		1.83	300	2,000	91072824
	3-Hour	14.2	170	1,800	87102612
		13.3	10	2,000	88060815
		13.7	310	2,000	89071515
		11.7	120	3,000	90072809
		14.4	290	1,800	91082912
PM_{10}	Annual	0.77	290	429	87123124
		0.96	270	403	88123124
		0.87	300	465	89123124
		0.97	270	403	90123124
		0.89	300	465	91123124
	24-Hour	3.79	250	429	87112324
		3.95	270	403	88111624
		4.89	270	403	89122924
		4.25	270	403	90112924
		4.34	280	409	91010224
NO_2	Annual	0.38	300	4,000	87123124
		0.33	270	4,000	88123124
		0.40	300	4,000	89123124
		0.45	300	4,000	90123124
		0.43	300	4,000	91123124
CO	8-Hour	203	220	1,500	87053016
		198	260	2,000	88061816
		196	310	2,000	89071516
		176	310	2,000	90052816
		224	310	2,000	91072416
	1-Hour	1,017	320	900	87072711
		1,036	310	900	88072611
		1,017	260	1,200	89081111
		1,064	300	900	90070112
		1,013	350	900	91061611

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Based on the 5-year meteorological record from the National Weather Service station in West Palm Beach, 1987 to 1991.

[b] Relative to Boiler No. 4 Stack Location.

Table 6-7. Maximum Pollutant Impacts Predicted for the Proposed Project in the Clewiston Mill Vicinity-Screening Analysis with Proposed Boiler No. 8 at 80 Percent Load (Revised July 21, 2003)

Pollutant	Averaging Time	Concentration[a] (ug/m^3)	Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)
SO_2	24-Hour	1.49	300	5,000	87062024
		1.58	260	2,000	88061824
		1.40	330	4,000	89060924
		1.90	320	3,000	90101024
		1.76	300	2,000	91072824
	3-Hour	13.8	170	1,500	87102612
		12.6	10	1,800	88060815
		13.1	170	1,800	89102612
		10.7	270	1,800	90070712
		13.8	290	1,500	91082912
PM_{10}	24-Hour	3.79	250	429	87112324
		3.95	270	403	88111624
		4.89	270	403	89122924
		4.25	270	403	90112924
		4.34	280	409	91010224
CO	8-Hour	196	220	1,500	87053016
		188	260	1,800	88061816
		190	310	2,000	89071516
		171	310	2,000	90052816
		225	290	3,000	91052124
	1-Hour	866	360	600	87091812
		908	310	900	88072611
		831	260	1,200	89081111
		912	320	900	90080511
		913	360	900	91073114

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Based on the 5-year meteorological record from the National Weather Service station in West Palm Beach, 1987 to 1991.

[b] Relative to Boiler No. 4 Stack Location.

Table 6-8. Maximum Pollutant Impacts Predicted for the Proposed Project in the Clewiston Mill Vicinity-Refined Analysis for Comparison to the PSD Class II Significant Impact Levels (Revised July 21, 2003)

Pollutant	Averaging Time	Boiler No. 8 Operating Load	Concentration (ug/m^3)	Receptor Location[a] Direction (degree)	Receptor Location[a] Distance (m)	Time Period (YYMMDDHH)	Significant Impact Level (ug/m^3)
SO_2	Annual	100	0.09	299	5,000	90123124	1
	24-Hour	100	2.32	323	3,800	90101024	5
		80	2.22	323	3,400	90101024	
	3-Hour	100	14.6	289	1,700	91082912	25
		80	13.9	289	1,600	91082912	
PM_{10}	Annual	100	0.96	270	403	88123124	1
		100	0.97	270	403	90123124	
	24-Hour	100	4.89	270	403	89122924	5
		80	4.89	270	403	89122924	
NO_2	Annual	100	0.45	300	4,100	90123124	1
CO	8-Hour	100	245	308	2,100	91072416	500
		80	233	308	1,900	91072416	
	1-Hour	100	1,183	301	800	90070112	2,000
		80	1,039	301	800	90070112	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Relative to Boiler No. 4 Stack Location.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 16, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: **Request for Additional Information - Reminder**
Project No. 0510003-021-AC (PSD-FL-333)
Clewiston Sugar Mill and Refinery
Proposed New Boiler 8

Dear Mr. Raiola:

On May 22, 2003, the Department received additional information regarding your application for an air permit, which proposes to construct a new 1031 MMBtu/hour boiler to support operations of the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. On May 28, 2003, the Department met with representatives of U.S. Sugar in Tallahassee to discuss remaining information necessary to complete the application, which included the following general items:

- Revised air quality analysis for the corrected site plan and potential changes to downwash impacts;
- Revised emission profile for the proposed boiler with potentially higher uncontrolled NOx rate and lower CO/VOC rates;
- SNCR details including NOx and ammonia performance guarantees (discussed estimated equivalent range for NOx standard between 0.11 – 0.14 lb/MMBtu for a 30-day rolling average and 10 – 15 ppm ammonia slip);
- Additional details for the alternate sampling procedure for opacity including critical ESP parameters and supplementary monitoring (similar to a "CAM" plan);
- Discussion/recommendation of excess emissions ranges and permit conditions;
- Requested gaseous emission standards in terms of "ppmvd @ 3% oxygen" (standards in terms of "lb/MMBtu" would be listed for informational purposes);

This is a reminder that the application remains incomplete. In order to continue processing your application, the Department will need the additional information listed above and discussed at the May 28th meeting. The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner
New Source Review Section

cc: Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

COMPLETE THIS SECTION ON DELIVERY

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Street, Apt. No.; or PO Box No. 111 Ponce DeLeon Ave.
City, State, ZIP+4 Clewiston, FL 33440

PS Form 3800, January 2001 See Reverse for Instructions

Golder Associates Inc.

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

Golder Associates

RECEIVED

MAY 22 2003

BUREAU OF AIR REGULATION

May 21, 2003

0237619

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Attention: Mr. Jeffery Koerner, P. E.

RE: United States Sugar Corporation (U.S. Sugar) – Clewiston Mill
Proposed New Boiler No. 8
DEP Project No. 0510003-021-AC (PSD-FL-333)

Dear Mr. Koerner:

U. S. Sugar is in receipt of the Department's request for additional information (RAI) dated April 25, 2003, for the above referenced project. The project is for the proposed primarily bagasse-fired Boiler No. 8, a new 550,000 lb/hr steam. Responses to each of the Department's requests are provided below, in the same order as they appear in the letter.

1. **Boiler No. 8**

The bagasse feed rate and the boiler heat input rate will be determined consistent with standard practice in the sugar industry. The boiler heat input rate will be determined by continuously measuring steam production rate, steam pressure and temperature, and feedwater temperature. Using the steam enthalpies and the design thermal efficiency of 62 percent, the heat input rate will be determined. The bagasse feed rate will be calculated based on the heat input rate and the average bagasse heating value for the Clewiston mill of 3,900 Btu/lb (wet basis).

The fuel-air ratio will be controlled by adjusting the primary (undergrate) and secondary (overfire) airflow to the boiler. The master pressure controller output signal will pass through a predefined ratio station, which then becomes the setpoint for the airflow controllers. The airflow signal is then trimmed by the oxygen controller, which trims the airflow to a predetermined oxygen level. The oxygen content of the flue gas will be measured in the boiler outlet duct prior to the airheater to ensure that the flue gas reading is not affected by dilution from tramp air. The setpoint of the oxygen controller will vary with load and fuel quality. The operator will also be able to manually adjust the air flow to address situations where the fuel may be very wet, in order to maintain steam rate, maintain proper combustion conditions, and control CO and opacity.

The sootblower design has not yet been finalized, but it is likely that the following sootblowers will be fitted to the boiler:

- Two retractable blowers between the primary and secondary superheaters.
- Two retractable sootblowers between the secondary superheater and the mainbank.
- Two fixed rotary blowers in the centre of the mainbank.
- Four rake type sootblowers – one above each economiser bank.

It is anticipated that the sootblowers will be used once every 8-hour shift. The sequence will be from the front of the boiler towards the rear of the boiler, i.e., from the primary superheater to the economizer. The duration of sootblowing will be approximately 30 to 45 minutes. It is anticipated that opacity and particulate emissions will increase during the operation of the sootblowers. However, it is not possible to quantify the magnitude of emissions during this time.

The normal operating range of the flue gas oxygen will be dependent upon boiler load, the quality of the fuel, and the type of fuel.

- Under normal sugar mill operating conditions, the boiler exit O_2 is expected to be between 3.0 and 4.0%. High fuel moisture, high ash content and low load conditions could result in the boiler exit O_2 increasing to 5.0 to 6.0%.
- The boiler exit O_2 while firing only fuel oil will range between 8.0 and 9.0%. This is because of the tramp air required for cooling of the stoker, pneumatic distributors, and overfire air nozzles during fuel oil firing.
- The stack O_2 for both cases could be 1 to 2% higher depending on the amount of ambient air infiltration there is across the system.

During the milling off-season, Boiler No. 8 is expected to be the primary boiler used to support the refinery. Boiler Nos. 7 and 8 will not normally operate at the same time during the off-season. However, Boiler Nos. 4 and 7 could operate at the same time in the off-season, when Boiler No. 8 is off-line.

2. **Requested Fuels**

U. S. Sugar will install dual-fuel burners in Boiler No. 8, capable of burning either No. 2 fuel oil or natural gas. However, natural gas is not yet available at the site. Therefore, U. S. Sugar will agree to not pursue the gas option at this time. The permit should recognize the dual-fuel capability of the burners.

3. **Requested Capacity Restrictions**

Comment is acknowledged. Note that PSD applicability review as if the boiler were not yet constructed would only apply to those pollutants for which PSD review was originally avoided. PSD applicability for pollutants undergoing PSD review for the original construction permit would be based on the PSD requirements for modifications to existing sources.

4. **CO and VOC Emissions**

As shown in Appendix A, Item 5.E of the application, the calculation of mass CO emissions was based on 363 ppmvd @ 7 percent O_2. Therefore, to perform the calculation, the gas flow rate must first be corrected to 7 percent O_2. The ppm concentration and the flue gas flow rate must both be corrected to the same oxygen level.

The proposed CO emission rate for Boiler No. 8 is 356 lb/hr at the maximum heat input rate of 936 MMBtu/hr, which equates to 0.38 lb/MMBtu. This emission rate is believed to be achievable on a 12-month rolling average basis, and also nets out of PSD review. CO emissions in terms of ppm were provided only because the proposed MACT standard is in these terms. The proposed maximum mass CO emission rate of 356 lb/hr or 0.38 lb/MMBtu does not vary as a function of flue gas oxygen. However, the calculated ppmvd concentrations will change as the flue gas oxygen level changes. The flue gas concentrations shown in Appendix A are at 3 percent and 7 percent O_2, for informational purposes.

As shown in Appendix A of the application, the proposed annual CO limit of 0.38 lb/MMBtu is equivalent to 467 ppmvd @ 3 percent O_2. Therefore, at 400 ppmvd, the limit would become 0.325 lb/MMBtu (0.38 x 400/467) and 305 lb/hr.

As demonstrated in the application, meeting a CO limit of 400 ppmvd on a 24-hour average basis is not achievable for a bagasse boiler. We would agree to the proposed limit of 363 ppmvd @ 7 percent O_2 (equivalent to 467 ppmvd @ 3 percent O_2) as being a target level on a 1-hour average, in the same way that the CO monitor is used on Boiler No. 4 at Clewiston, i.e., as a trigger level for corrective action.

Although a VOC limit of 0.03 lb/MMBtu may be achievable under best circumstances, it may not be achievable at all times, considering the nature of the bagasse fuel. An emission limit must be met at all times, excluding startup, shutdown and malfunction. Note that the proposed 12-month rolling average CO limit is 0.38 lb/MMBtu; therefore, higher short-term levels of CO emissions are expected to occur. VOC emissions are expected to vary in a similar manner.

As the Department correctly notes, Boiler No. 7 test data showed VOC emissions of 0.11 lb/MMBtu at a CO emission rate of 0.39 lb/MMBtu. Although this test may not reflect the best combustion conditions, this is the nature of bagasse fuel. Higher moisture fuel can and does occur at times. Boiler No. 7's VOC emission limit is 0.212 lb/MMBtu, so this test was not a violation, but would have been if the limit were 0.03 or 0.06 lb/MMBtu. While Boiler No. 8 may produce lower VOC emissions than Boiler No. 7, absent actual operating data, it is difficult for U. S. Sugar to accept a VOC limit of less than 0.06 lb/MMBtu at this time, given the nature of bagasse fuel. The proposed limit is consistent with the recently issued PSD permit for Palm Beach Power Corporation and New Hope Power's current permit limit. The proposed limit is more than three times lower than the current limit for Boiler No. 7.

The VOC test data for Boiler No. 7, provided in Appendix D of the application, does not include methane/ethane. As noted in the VOC column title, the VOC emissions were determined using EPA Methods 25A and 18. Method 18 was used to determine methane content, which was then subtracted from the Method 25A results, to provide non-methane VOC.

5. **Particulate Matter Controls**

Wet Cyclone: To protect the ID fan from abrasion, two low efficiency non-saturating wet cyclones will be installed in parallel. The attached sketch 1/49-999-026 shows the layout of one of the units. Gas enters the cyclone through a venturi throat. The area of the throat is manually adjustable. Spray nozzles are incorporated in the throat.

After leaving the venturi, the gas spirals upwards through the vessel. Coarse abrasive ash particles adhere to the periphery, from where they are washed down to the discharge hopper. The hopper has two outlets: a normal outlet and an emergency outlet. The latter is used in case the normal outlet blocks. The pressure drop across the wet cyclone will be about 4" w.g. at maximum load.

Gas leaves the wet cyclone through a port at the top of the vessel, and is ducted to the ID fan inlet. Each cyclone will be designed to handle approximately 191,000 acfm. The two cyclones will require a total of approximately 400 to 500 gallons per minute (gpm) of water.

The expected wet cyclone collection efficiency is as follows:

Particle size (um)	Collecting efficiency
5	3%
30	30%
100	85%

No inlet/outlet testing has been conducted on the wet cyclone installed on Boiler No. 7.

ESP: Currently, budgetary proposals are being solicited from the following ESP suppliers:

Environmental Elements Corporation
Baltimore, MD, USA

PPC Industries
Longview, TX, USA

FL Smidth - Air Tech Inc.
Houston, TX, USA

It is intended to expand this list to include other qualified suppliers when firm price bids are requested. The ESP will be a dry, negative corona plate ESP. Please see Table 1 (page 9 of this letter), which presents data taken from preliminary ESP vendor proposals.

The final ESP selected will have multiple T-R sets. Also, the final selected unit may not have nine fields.

The following description of the rapping system used to remove ash from the ESP is taken from one of the budgetary ESP quotations:

> The electric impulse rapper has been specifically designed for rapping the collecting surfaces, discharge electrodes and perforated distribution plates. The rappers are the single impulse gravity impact type consisting of an integral DC coil and steel housing assembly, a 20-lb piston and mounting hardware.
>
> Rapper impact is precisely repeatable. Intensity of impact and frequency of operation are controlled by a microprocessor-based controller.
>
> Trough type hoppers are fabricated from 3/16 inch ASTM A-36 steel with external stiffeners of uniform depth to provide support for thermal insulation and siding. The hoppers are designed to support full dust load. The sides and ends are sloped 60° and 75°, respectively, from the horizontal. The valley angle resulting from this design is 57.5°. The between field baffles are extended to the hopper outlet to eliminate gas bypassing in the hoppers. Each hopper is provided with high-level alarms, electric resistance heating elements, strike plates for manual rapping. Hoppers should not be used for storage.

The main parameter for the ESP during startup is gas temperature. Gas temperature entering the ESP should be at 300°F or higher for a minimum of 10-minutes before the ESP is energized. This is necessary to allow any condensation on the ESP internals (plates, rods, etc) to dry out before the unit is energized. This practice prevents wet dust on the plates from sealing and fouling the plates.

The boiler design and the warm-up curve dictate the elapsed time from initial fuel firing. Standard practice is to limit boiler warm-up to no more than 100° per hour (boiler water temperature). It is expected that it will take approximately 4-6 hours to achieve a flue gas temperature of 300°F.

COMS: Our justification for the Alternate Sampling Procedure (ASP) for opacity, requested in lieu of the continuous opacity monitoring system (COMS) required by NSPS Subpart Db, is that Boiler No. 8 will be operated infrequently on fuel oil. The annual capacity factor on fuel oil will be limited to 10 percent. EPA has issued approval of numerous ASPs for Subpart Db boilers that have limited their annual fuel oil capacity to 10 percent or less.

U. S. Sugar would oppose the use of a COMS, based on the fact that there is no demonstrated correlation between opacity and mass emissions for fuel combustion sources. Also consider that the CAM requirements (40 CFR Part 64) will ultimately apply to Boiler No. 8 for PM emissions. At that time, U. S. Sugar will be required to propose indicator parameters and develop parametric ranges for those parameters.

6. **Sulfur Dioxide and Sulfuric Acid Mist Controls**
While there is not much difference between the Department's suggested SO_2 emission limit of 0.05 lb/MMBtu for bagasse firing, there is also no evidence to suggest a limit less than 0.06 lb/MMBtu is achievable. Only one SO_2 test is available from the sugar industry for a bagasse boiler controlled with an ESP (U. S. Sugar Boiler No. 7). The proposed limit is based on the recently issued PSD permit for Palm Beach Power Corp, and the current permit limits for U. S. Sugar Boiler No. 4 and New Hope Power. It is about three times lower than the current SO_2 limit for Boiler No. 7 of 0.17 lb/MMBtu.

SO_2 control is inherent to the bagasse combustion process. U. S. Sugar will not have control over the inherent removal mechanisms. If the Department sets a lower SO_2 standard, it should allow revisiting of the standard if further test data indicate that the standard is too low.

7. **Controls for Nitrogen Oxides**
The proposed Boiler No. 8 is neither a coal-fired boiler nor a municipal waste combustor. There are constituents in sugarcane and the resulting bagasse fuel that lead to severe catalyst poisoning, making conventional SCR infeasible. To determine the feasibility of SCR, site-specific ash analysis and boiler data was provided to catalyst manufacture Haldor Topsoe. U. S. Sugar obtained an ESP ash sample from Boiler No. 7. The sample was sent to the lab for analysis. The results are shown in Attachment A, along with published analysis for coal. As shown, the potassium, sulfur trioxide, and phosphorus content of the ash was very high compared to coal ash. The bagasse ash also showed high levels of chlorine.

Flemming Hansen of Haldor Topsoe responded with the following statement:

> "We have looked at the data you sent and notice that the content of K in the ash is 10%, which is twice as much as we observed in a testing on the wood fired boiler. In addition the content of Cl is > 5%. Thus a very large amount of KCl aerosols (a severe catalyst poison) is to be expected, which will result in a very rapid deactivation in a high dust position. I will expect that the deactivation will be so high, that it is not manageable in practice."

Based on Haldor Topsoe's site-specific determination, SCR placed directly after the boiler should be considered infeasible for this project.

There currently is no experience of SCR installations on bagasse-fired boilers. However SCR has been placed on MSW units in a "tail-end" configuration. This type of installation allows the SCR to be placed downstream of all other pollution controls, minimizing the chance of severe catalyst degradation or fouling due to the ash constituents. Although MSW and bagasse fired boilers do not produce similar ash, they both have the potential of catalyst poisoning and therefore "tail-end" SCR is feasible for bagasse-fired boilers. It should be noted that, as with conventional SCR, there is no experience of "tail-end" SCR installations on bagasse-fired boilers.

A cost analysis for "tail-end" SCR was prepared based on a recent cost quote from Hamon Research-Cottrell for a similar sized bagasse fired boiler. The cost quote assumed a SCR operating temperature of 700 degrees F. Therefore, the annual cost includes the cost associated with reheating the flue gas from 330 to 700 degrees F. The reheat costs are based on No. 2 fuel oil, since natural gas is currently not available at the facility.

The "tail-end" SCR cost analysis is presented in Attachment B. Based on the vendor quote and the OAQPS Cost Control Manual, the total capital cost of "tail-end" SCR for Boiler No. 8 is estimated at \$5.2 million. The total annualized cost of applying "tail-end" SCR is estimated at \$7.05 million per year. The resulting cost effectiveness is \$11,840 per ton of NO_x removed. Therefore, "tail-end" SCR is considered to be economically infeasible for Boiler No. 8.

It is noted that this does not include the additional pollutant emissions caused by the reheat system. Additional NO_x emissions associated with such a system are estimated at 52 TPY or higher. The cost effectiveness would increase to over \$13,000 per ton considering these additional NO_x emissions.

SNCR: As discussed in the application, our primary concerns surrounding SNCR are the potential effects on boiler operation due to ammonia slip and ammonium bisulfate formation on the downstream boiler components. The former Osceola Power L. P. facility experienced severe superheater tube failures associated with increased urea injection to meet its NO_x emissions limit. SNCR has never been applied to a purely bagasse-fired boiler. The bagasse fuel characteristics and combustion characteristics are much different than wood or wood/bagasse firing. The effects of the increased moisture in the flue gas and other constituents in the ash (sulfur, potassium, chlorine, phosphorus, etc.) may have a yet unknown and unpredictable effect upon boiler components. As demonstrated is separate proceedings, the boilers at the Clewiston Mill are already subject to increased wear, corrosion and erosion due to fuel constituents. The use of SNCR could compound these problems.

We ask that the Department reconsider its position on SNCR. The Clewiston mill is located in a remote, rural area, where NO_x emissions are less likely to contribute to high ozone levels in the populated urban areas. The already low proposed NOx emissions rate of 0.22 lb/MMBtu does not warrant further reduction.

NO_x CEMS: Previous NO_x testing on bagasse boilers has indicated NO_x emissions do not vary greatly, due to the high moisture content of the fuel, which suppresses NO_x emissions. Test results from Boiler No. 7 at Clewiston confirm this. There does not appear to be any requirement or need for a NO_x CEMS.

8. **Boiler MACT**
Based on the Department's position, there is no reason a the present time to require that Boiler No. 8 meet the MACT, since the MACT will apply regardless of whether it is included in the construction permit. In addition, neither the final form of the MACT nor the emission limits are known at this time. Further, the final MACT rule could exempt non-major new sources from the MACT requirements. Therefore, it would be premature and speculative to require the boiler to meet the limits in the proposed MACT standard. The final standards could be totally different than those proposed. The Department should accept U. S. Sugar's proposed CO limit of 0.38 lb/MMBtu, which avoids PSD review and therefore exempts the proposed boiler from BACT.

9. **Bagasse Handling System**
Refer to Section 2.4 of the PSD report. U. S. Sugar had previously permitted six (6) bagasse handling system dust collectors as part of a modification of the bagasse handling system (refer to permit no. 0510003-011-AC). With Boiler No. 8, and associated revisions to the system, there will now only be five (5) dust collectors. The grain loadings, air flow rates, and control efficiencies of the dust collectors are shown in the footnotes to Attachments UC-EU2-G and UC-EU2-J3 of the application form. In essence, one of the previously permitted dust collectors has been eliminated.

10. **Refinery Operations**
U. S. Sugar is not requesting any changes to existing permit limits for the refinery. However, due to the potential increase in actual refinery operation due to Boiler No. 8, the increase in emissions has been quantified, as described in Section 3.5.2 and shown in Table 3-3 of the PSD report.

11. **CAM Plan**

Comment is acknowledged.

12. **Air Quality Modeling Review**

U. S. Sugar has received the Department's letter dated May 2, 2003, concerning the air quality modeling analysis. Two comments were contained in the letter, and are both addressed below.

A. Attached is the requested drawings. Building data from the BPIP file were overlaid on an aerial of the mill. These BPIP data were used in previous air modeling analyses for the mill. As shown in the figure, the buildings used in the model are generally aligned with those shown in the aerial. Any differences are expected to produce minimal, if any, differences in predicted concentrations. It should be noted that the pellet warehouse was modeled as it exists, even thought the eastern portion of the warehouse will be removed once Boiler No. 8 is constructed. Since the height of the warehouse is relatively low compared to Boiler No. 8's stack, it does not have an effect on building downwash effects for that stack.

B. Additional information regarding the air quality impacts of general commercial, residential, industrial and other growth that has occurred in the area since August 7, 1977, please refer to Attachment C.

13. **Comments from EPA or NPS**
We have not received any comments from EPA as of this date. Comments from the National Park Service (NPS) are addressed in the following.

NO_x BACT: U. S. Sugar Clewiston Boiler No. 4 test data demonstrated an average uncontrolled NOx emissions rate of 0.08 lb/MMBtu. However, this boiler was originally built as a coal-fired boiler in the 1950's and moved to Clewiston and converted to bagasse firing in1985. Therefore, its NOx emissions are not representative of a modern bagasse-fired boiler. Uncontrolled NO_x emissions of 0.22 to 0.26 lb/MMBtu are representative of a modern bagasse-fired boiler (reference Clewiston Boiler No. 7 and New Hope Power Partnership). The higher NO_x emissions are a result of better combustion of the fuel, which also results in lower CO, VOC and organic HAP emissions. U. S. Sugar has specified a NO_x limit on the lower end of this range in an attempt to force the boiler vendors to design to the lowest achievable NO_x level without add-on control equipment. However, there is a risk that such a low level may not be achievable at all times.

SO_2: U. S. Sugar should not be required to meet a fuel oil sulfur limit predicated on regulations that will go into effect in 2006. This is premature, speculative, and not acceptable. First of all, the regulation could be revised and not go into effect in 2006, or be replaced by a less stringent standard. Secondly, the cost of such fuel is not known at this time, and since costs are considered in the BACT analysis, this alternative should be rejected. U. S. Sugar cannot control what other facilities propose as BACT, but to propose a technology that is not yet even available or known to be cost effective is not considered appropriate.

Please call or e-mail me if you have any questions concerning this additional information.

Sincerely,
GOLDER ASSOCIATES INC.

David A. Buff

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

David T. Larocca

David T. Larocca
Project Engineer

DB/DTL/jej

Enclosure

cc: Don Griffin
Sarah Watson
Ron Blackburn, DEP
C. Holladay
G. Worley, EPA
D. Bunyak, NPS

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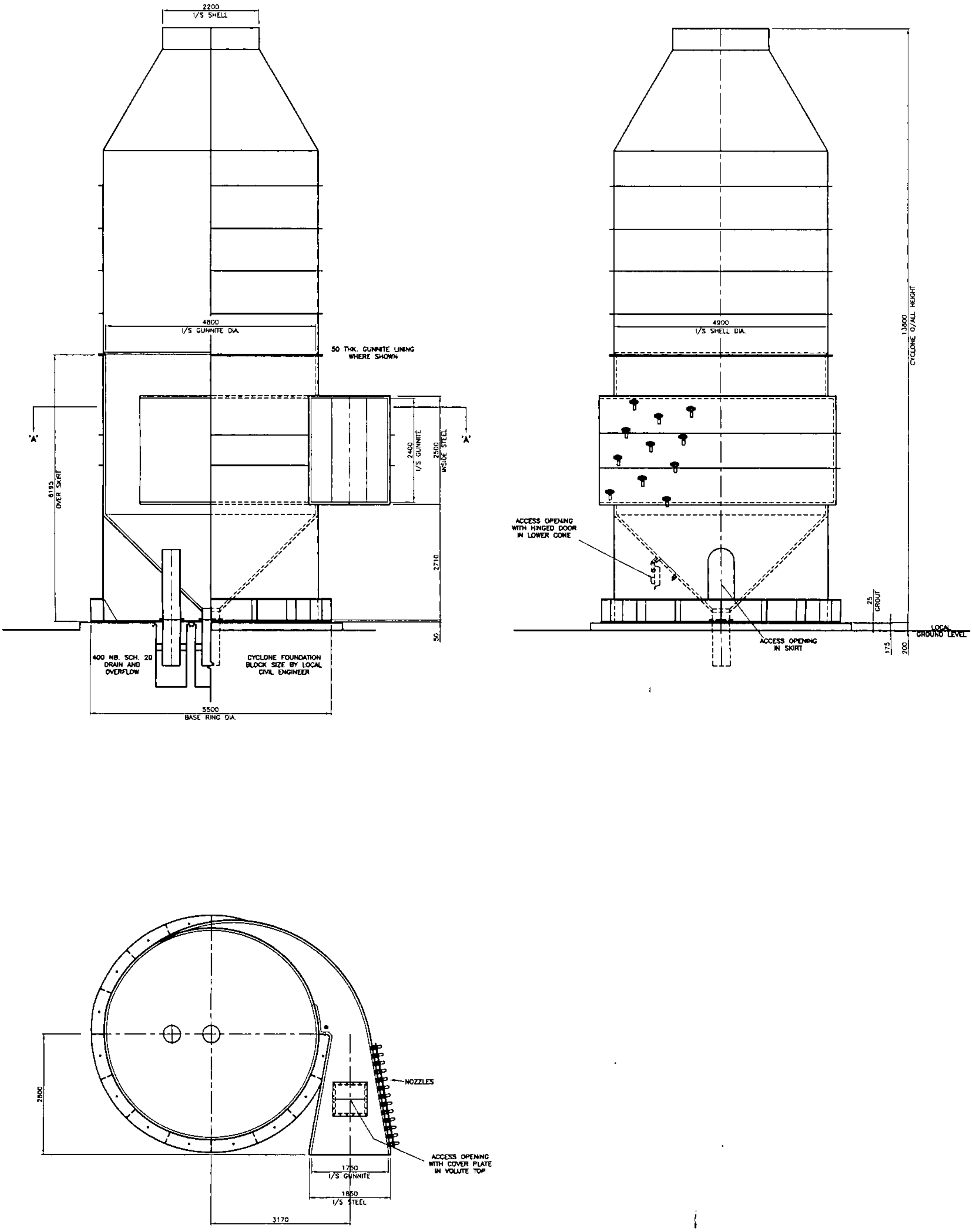
Table 1: ESP Performance Summary

PERFORMANCE PARAMETER	UNITS	RANGE of VALUES
DUST SOURCE		Combustion
FUELS		Bagasse / Fuel Oil
GAS VOLUME	ACFM	425,425
GAS TEMPERATURE	F	255 – 335
GAS MOISTURE	$\%_v$	24.3 - 25.0
GAS PRESSURE	IWG	- 10
INLET PM LOADING	#/MMBTU	1.00
EXIT PM LOADING	#/MMBTU	0.03
REMOVAL EFFICIENCY	%	97.00
PRESSURE DROP	IWG	0.5 - 1.0
OPACITY	%	10
POWER CONSUMPTION	KW	231 – 303
FIELD VOLTAGE	KV	55 – 70
CURENT	mA	1,700
NO. of FIELDS		3 – 4
FIELD LENGTH	FT	36.4 - 40.8
COLLECTING PLATE HT	FT	36
TOTAL COLL. AREA	FT^2	91,665 - 144,550
SP. COLL. AREA (SCA)	FT^2/kACFM	215.5 - 339.8
GAS VELOCITY	FT/SEC	4.01 - 4.22
TREATMENT TIME	SEC	8.6 - 10.2
ASPECT RATIO		1.01 - 1.36

GENERAL NOTES
ALL DIMENSIONS IN MILLIMETRES.



magasiner technology

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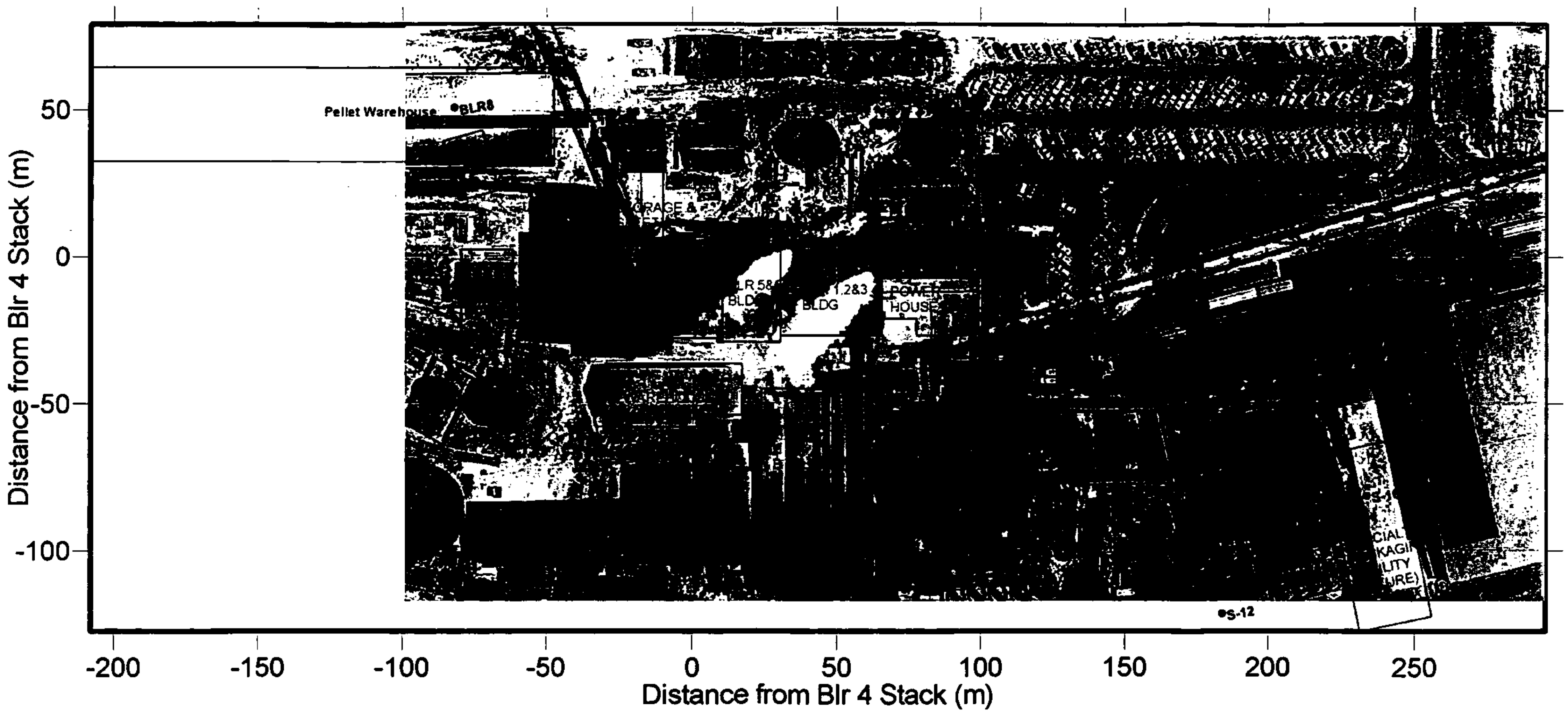
THERMAL ENERGY SYSTEMS CC
THIRD ANGLE PROJECTION

U.S. SUGAR CORPORATION – CLEWISTON
PRELIMINARY ARRANGEMET
WET CYCLONE
Thermal Energy Systems

DRAWN	J.R.W.	9/5/03	SCALE 1:40	DRG. No.	1/49–999–026
CHECKD	JRW				
APPRVD	B.M		REV	A	



Facility Plot Plan
U.S. Sugar – Boiler No. 8

Source: Golder, 2003.

Golder Associates

ATTACHMENT A

Table A-1. Cost Effectiveness of "Tail-End" SCR, U.S. Sugar Cogeneration Boiler 8

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
SCR Basic Process	Vendor quote[b]	2,093,684
Ammonia Storage System	Vendor quote[c], 30,000 galllon storage tank + valves	210,000
Auxilary Equipment (Reheat)	20% of SCR equipment cost	418,737
Emissions Monitoring	15% of SCR equipment cost	209,368
Foundation and Structure Support	8% of SCR equipment cost	167,495
Control Room and Enclosures	4% of SCR equipment cost, engineering estimate	83,747
Transition Ducts to and from SCR	4% of SCR equipment cost, engineering estimate	83,747
Wiring and Conduit	2% of SCR equipment cost, engineering estimate	41,874
Insulation	2% of SCR equipment cost, engineering estimate	41,874
Motor Control and Motor Starters	4% SCR of equipment cost, engineering estimate	83,747
SCR Bypass Duct	$127 per MMBtu/hr	96,520
Induced Draft Fan	5% of SCR equipment cost, engineering estimate	104,684
Taxes	Florida sales tax, 6%	125,621
Total DCC.		3,761,099
INDIRECT CAPITAL COSTS (ICC):		
General Facilities	5% of DCC	188,055
Engineering Fees	10% of DCC	376,110
Performance test	1% of DCC	37,611
Process Contingencies	5% of DCC	188,055
Total ICC:		789,831
Project Contingencies	15% of DCC + ICC	682,639
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + Project Contingencies	5,233,569
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	24 hours/week, $16/hr, 52 weeks/yr	$19,968
Supervisor	15% of operator cost	2,995
(2) Maintenance	Engineering estimate, 5% of catalyst replacement cost	23,481
(3) SCR Energy Requirement	0 3 % of output energy + 10 hp ammonia pump. @ $0.04/kW-hr	218,029
(5) Ammonia Cost	$495 per ton NH3, 19% Aqueous (Tanner,2002).	573,138
(6) Catalyst Replacement and disposal	20,000 hours, 7%; FWF = 0 374	469,624 [d]
(7) Reheat Energy Requirements	133.8 MMBtu/hr, $0.8/Gallon fuel oil; 75% C.F	5,169,237 [e]
Total DOC:		6,476,474
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.10979 times TCI (15 yrs @ 7%)	574,594
ANNUALIZED COSTS (AC):	DOC + CRC	7,051,067
BASELINE NO_x EMISSIONS (TPY) :	0.22 lb/MMBtu; 1030 MMBtu/hr; 75% capacity factor	744.4
MAXIMUM NO_x EMISSIONS (TPY) :	80% removal	148 9
REDUCTION IN NO_x EMISSONS (TPY):		595 5
COST EFFECTIVENESS:	$ per ton of NO_x Removed	11,840

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 4, Sixth edition.

[b] 2002 Hamon Research-Cottrell cost quote, 3 units = $4,250,000, includes SCR, ammonia flow control unit, and ammonia injection system. 1 cogeneration unit = $1,700,000. Original quote for 760 MMBtu/hr boiler. Cost scaled by a factor of 936/760 = 1.23

[c] Based on RM Technologies vendor quote for 30,000 gallon stainless steel horizontal tank, includes valves and transfer station

[d] SCR initial catalyst cost estimated to be 60% (based on experience with Englehard SCR systems) of the initial capital cost, FWF = future worth factor OAQPS (2.52).

[e] Based on reheating 400,000 acfm from 330 deg. F to 700 deg. F

ATTACHMENT B

Bagasse Fly Ash Compared to Coal Ash

Constituent	ESP Ash From Boiler No. 7	Coal Fly Ash				
		Class "F"	Class "C"	hvBb Utah	hvAb Penn.	hvC
Elemental analysis of ash (%)						
Silica (SiO_2)	33.04	58.0	35.9	52.5	51.1	52.0
Aluminum Oxide (Al_2O_3)	2.13	29.1	18.9	18.9	30.7	17.5
Iron Oxide (Fe_2O_3)	1.82	3.6	6.1	1.1	10.0	15.5
Titanium Oxide (TiO_2)	0.04	1.6	1.4	1.2	2.0	1.3
Calcium Oxide (CaO)	7.62	0.8	24.6	13.2	1.6	4.5
Magnesium Oxide (MgO)	3.55	0.8	5.4	1.3	0.9	1.1
Sodium Oxide (Na_2O)	0.26	0.1	1.9	3.8	0.4	0.6
Potassium Oxide (K_2O)	15.00	2.5	0.3	0.9	1.7	2.8
Sulfur Trioxide (SO_3)	9.32	0.2	2.3	6.2	1.4	4.2
Phosphorus Pentoxide (P_2O_5)	6.22	0.1	1.1	--	--	0.1
Barium Oxide (BaO)	--	0.1	0.7	--	--	--
Manganese Oxide (Mn_2O_3)	--	0.1	<0.1	--	--	--
Strontium Oxide (SrO)	--	0.1	0.4	--	--	--
Trace metals (ppm):						
Antimony	38					
Arsenic	10.4					
Cadmium	<1					
Chlorine	75,800					
Chromium	40					
Copper	340					
Lead	47					
Manganese	470					
Mercury	<0.1					
Nickel	11					
Selenium	2					
Tin	<100					
Vanadium	149					
Zinc	1,690					

HAZEN

Hazen Research, Inc.
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date	March 11 2003
HRI Project	009-555
HRI Series No.	C2/03
Date Rec'd.	03/04/03
Cust. P.O.#	

Golder Associates, Inc.
Fawn Bergen
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653

Sample Identification:
USSC-B8 Ash

Elemental Analysis of Ash (%)

SIO2	33.04
AL2O3	2.13
TIO2	0.04
FE2O3	1.82
CAO	7.62
MGO	3.55
NA2O	0.26
K2O	15.00
P2O5	6.22
SO3	9.32
CL	
CO2	
Total	79.00

Ash Fusion Temperatures (Deg F)

	Oxidizing Atmosphere	Reducing Atmosphere
Initial		
Softening		
Hemispherical		
Fluid		

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

Note: The ash was calcined @ 1110 deg F (600 C) prior to analysis.

Hazen Research, Inc.
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

DATE	April 1, 2003
PROJ. #	009-455
CTRL #	C2/03
REC'D	03/04/03

Golder Associates, Inc.
Fawn Bergen
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653

Sample Number: C2/03-1
Sample Identification: USSC-B8 Ash

Antimony, mg/kg	38
Arsenic, mg/kg	10.4
Cadmium, mg/kg	<1
Chlorine, mg/kg	75,800
Chromium, mg/kg	40
Copper, mg/kg	340
Lead, mg/kg	47
Manganese, mg/kg	470
Mercury, mg/kg	<0.1
Nickel, mg/kg	11
Selenium, mg/kg	2
Tin, mg/kg	<100
Vanadium, mg/kg	149
Zinc, mg/kg	1,690

By:

Gerard H. Cunningham
Fuel Laboratory Manager

The sample was ashed at 600 degrees Celsius prior to analysis.

ATTACHMENT C

GENERAL, RESIDENTIAL, COMMERCIAL, INDUSTRIAL GROWTH ASSOCIATED WITH THE ADDITION OF BOILER NO. 8 AT U.S. SUGAR CORPORATION'S CLEWISTON MILL

TABLE OF CONTENTS

1.0 INTRODUCTION

Florida Administrative Code (F.A.C.), 62-212.400(3)(h)(5), states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the construction and operation of Boiler No. 8. This information is consistent with the EPA Guidance related to this requirement in the Draft New Source Review Workshop Manual (EPA, 1990).

In general, there has been minimal growth in the area since 1977. The site is located in northeast Hendry County, to the south of Lake Okeechobee. Hendry County is the 8th largest county in Florida, comprising of 1,163 squares miles.

As stated in the PSD permit application, Boiler No. 8 is being constructed to meet current and projected demands for the Clewiston sugar mill. Additional growth as a direct result of the additional demand provided by the project is expected to be minimal. Construction of Boiler No. 8 will occur over approximately a 2-year period, requiring an average of approximately 25 workers during that time. It is anticipated that many of these construction personnel will commute to the site.

The addition of Boiler No. 8, coupled with the removal of Boiler No. 3, will result in no increase in operational workers at the site. The increase in production rate of the sugar refinery will not require any additional workers. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to operate Boiler No. 8 represents a small fraction of the population already present in the immediate area. Therefore, while there may be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated industrial and commercial growth, given the location at the existing Clewiston Mill. The existing commercial and industrial infrastructures are adequate to provide any support services that the project might require and would not increase with the operation of the project.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Hendry County. As such, the information presents information available from a variety of sources (e.g., Florida Statistical Abstract, FDEP, etc.) that characterizes Hendry County as a whole.

2.0 RESIDENTIAL GROWTH

2.1 POPULATION AND HOUSEHOLD TRENDS

As an indicator of residential growth, the trend in the population and number of household units in Hendry County since 1977 are shown in Figure C-1. The county experienced a 114 percent increase in population for the years 1977 through 2000. During this period, there was an increase in population of about 19,300. Similarly, the number of households in the county increased by about 4,700 or 77 percent since 1977.

2.2 GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT

Because of the limited number of workers needed to operate the project, residential growth due to the project is expected to be minimal.

3.0 COMMERCIAL GROWTH

3.1 RETAIL TRADE AND WHOLESALE TRADE

As an indicator of commercial growth in Hendry County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure C-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches and offices that sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977, retail trade has increased by 29 establishments and 1,013 employees or 28 and 128 percent, respectively. For the same period, wholesale trade has increased by 25 establishments and 179 employees, or 179 and 232 percent, respectively.

3.2 LABOR FORCE

The trend in the labor force in Hendry County since 1977 is shown in Figure C-3. The greatest number of persons employed in Hendry County has been in the agriculture, services and government sectors. Between 1977 and 1999, approximately 6,265 persons were added to the available work force, for an increase of 87 percent.

3.3 TOURISM

Another indicator of commercial growth in Hendry County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure C-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1978 and 2000, there was no change in the number of hotels and motels in the county; however there was a significant increase of 49 percent in the number of units at those facilities.

3.4 TRANSPORTATION

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Hendry County is presented in Figure C-5.

Much of the county's land is wetlands. A large part of the Big Cypress Seminole Indian Reservation is in the southern portion of the county. The county's main artery is State Road 80, which runs east-west through the northern section of the county. The only other major highway in the county is U.S. Highways 27. State and county highways in the county include S.R. 29, and County Roads 832, 833, 832, 846, and 858.

Between 1977 and 2001, there was an increase of about 280,000 VMT, or 86 percent, in the amount of travel by motor vehicles on major roadways in the county.

3.5 GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the project. The workforce needed to operate the proposed project represents a small fraction of the labor force present in the immediate and surrounding areas.

4.0 INDUSTRIAL GROWTH

4.1 UTILITIES

There are no existing power plants in Hendry County.

4.2 MANUFACTURING AND AGRICULTURAL INDUSTRIES

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Hendry County since 1977 is shown in Figure C-6. As shown, the manufacturing industry experienced a moderate increase of 25 percent from 1977 through 1997.

As another indicator of industrial growth, the trend in the number of employees in the agricultural industry, including sugar, in Hendry County since 1977 is also shown in Figure C-6. As shown, the agricultural industry experienced an increase in employment of 91 percent from 1977 through 2000.

4.3 GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT

Since the baseline date of August 7, 1977, there have been only a few major facilities built within a 35-km-radius of the plant site. The nearest such source is the Southern Gardens Citrus Processing Corporation. There are a limited number of facilities located throughout the 35-km radius area surrounding the U.S. Sugar facility. Based on the plot of nearby emission sources, Figure C-7, there has not been a concentration of industrial and commercial growth in the vicinity of the U.S. Sugar Clewiston Mill.

5.0 AIR QUALITY DISCUSSION

5.1 AIR EMISSIONS AND SPATIAL DISTRIBUTION OF MAJOR FACILITIES

The spatial distribution of major air pollutant facilities in Hendry County is shown in Figure C-7. Based on actual emissions reported for 1999 (latest year of available data) by EPA on its AIRSdata website, total emissions from stationary sources in the county are as follows:

- Sulfur dioxide (SO_2): 1,591 TPY
- Particulate matter (PM_{10}): 538 TPY
- Nitrogen oxides (NO_x): 1003 TPY
- Carbon monoxide (CO): 8,167 TPY
- Volatile organic compounds (VOC): 549 TPY

5.2 AIR EMISSIONS FROM MOBILE SOURCES

The trends in the air emissions of CO, VOC, and NO_x from mobile sources in Hendry County are presented in Figure C-8. Between 1977 and 2002, there were significant decreases in these emissions. The decrease in CO, VOC, NO_x emissions were about 81, 7, and 4 tons per day, respectively, which represent decreases of 80, 80, and 56 percent, respectively, from 1977 emissions.

5.3 AIR MONITORING DATA

Since 1977, Hendry County has been classified as attainment for all criteria pollutants. Because of the minimal industrial, commercial, and residential development in Hendry County over the last 25 years, PM air quality monitoring data have not been collected in the county by the FDEP, except for total suspended particulates (TSP) for years 1977 through 1988. Air quality monitoring data have been collected in the adjacent county of Palm Beach due to the industrial, commercial, and residential activities that have occurred in the eastern portion of the county. For this evaluation, the air quality monitoring data collected at the monitoring station nearest to Clewiston were used to assess air quality trends since 1977.

For SO_2 concentrations, air quality monitoring data collected over the years from Riviera Beach, Belle Glade, and South Bay were used in the evaluation. For NO_2 concentrations, air quality monitoring data from West Palm Beach and Palm Beach were used. For PM_{10} concentrations, air quality monitoring data from Clewiston and Belle Glade were used in the evaluation. For ozone concentrations, air quality monitoring data from West Palm Beach, Palm Beach, Delray Beach, and

Royal Palm Beach were used. Data collected from these stations are considered to be generally representative of air quality in Hendry County. Because these monitoring stations are generally located in more industrialized areas than the Clewiston area, the reported concentration are likely to be somewhat higher than that experienced at the Clewiston site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable ambient air quality standards. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources as well as meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than those monitored concentrations.

In addition, since 1988, PM in the form of PM_{10} has been collected at the air monitoring stations due to the promulgation of the PM_{10} AAQS. Prior to 1989, the AAQS for PM was in the form of TSP concentrations, and this form was measured at the stations.

5.3.1 SO_2 CONCENTRATIONS

The trends in the annual, 24-hour, and 3-hour average SO_2 concentrations measured near the Clewiston site since 1977 are presented in Figures 8-9 through 8-11, respectively. SO_2 concentrations have been measured at three stations for various time periods throughout these years.

As shown in these figures, concentrations have been and continue to be well below the AAQS.

5.3.2 PM_{10}/TSP CONCENTRATIONS

The trends in the annual and 24-hour average PM_{10} and TSP concentrations since 1977 are presented in Figures A-12 and A-13, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to PM_{10}.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS. Since 1988 when PM_{10} concentrations have been measured, the PM_{10} concentrations have been and continue to be below the AAQS.

5.3.3 NO_2 CONCENTRATIONS

The trends in the annual average NO_2 concentrations measured at the nearest monitors to Clewiston are presented in Figure C-14. As shown in this figure, measured NO_2 concentrations have been well below the AAQS.

5.3.4 OZONE CONCENTRATIONS

The trends in the 1-hour average ozone concentrations since 1977 are presented in Figure C-15. As shown in this figures, even in the more urbanized areas of Palm Beach County, the measured ozone concentrations have been well below the AAQS.

5.4 AIR QUALITY ASSOCIATED WITH THE OPERATION OF THE PROJECT

The air quality data measured in the region of the Clewiston Mill indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for Boiler No. 8 are predicted to be below the significant impact levels, the air quality concentrations in the region are expected to remain below and comply with the AAQS when Boiler No. 8 becomes operational.

Figure C-1. Population and Household Unit Trends in Hendry County

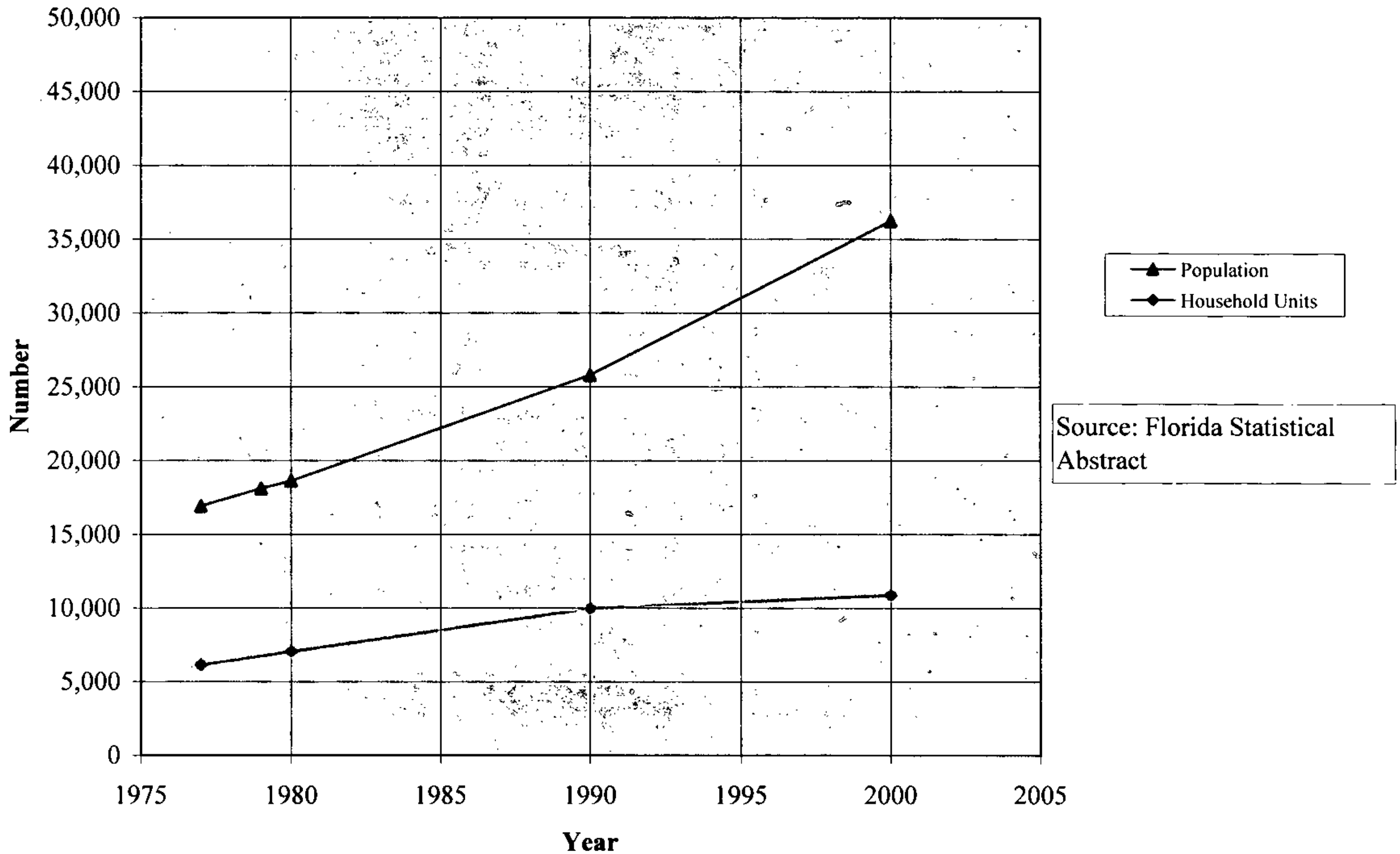


Figure C-2. Retail and Wholesale Trade Trends in Hendry County

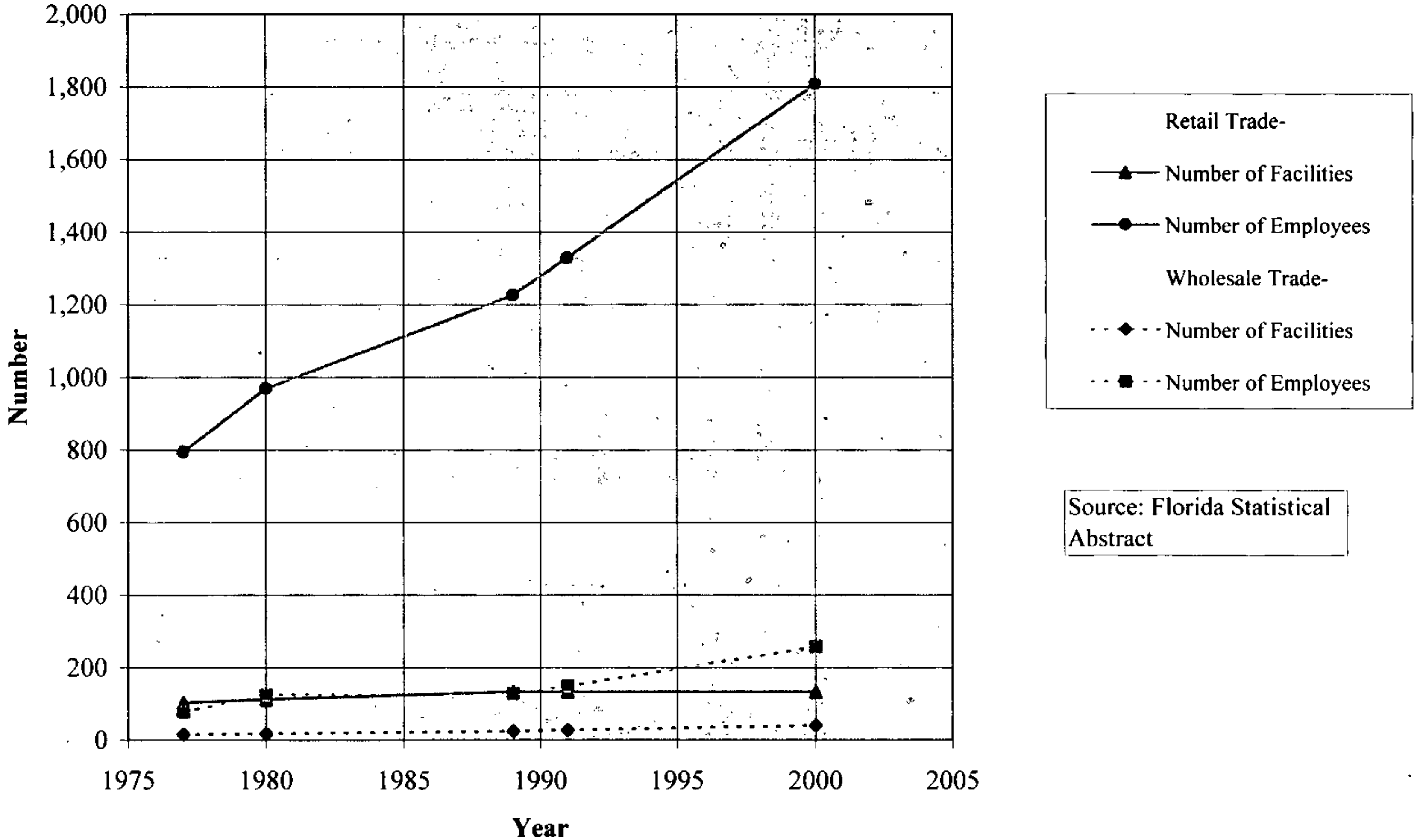


Figure C-3. Labor Force Trend in Hendry County

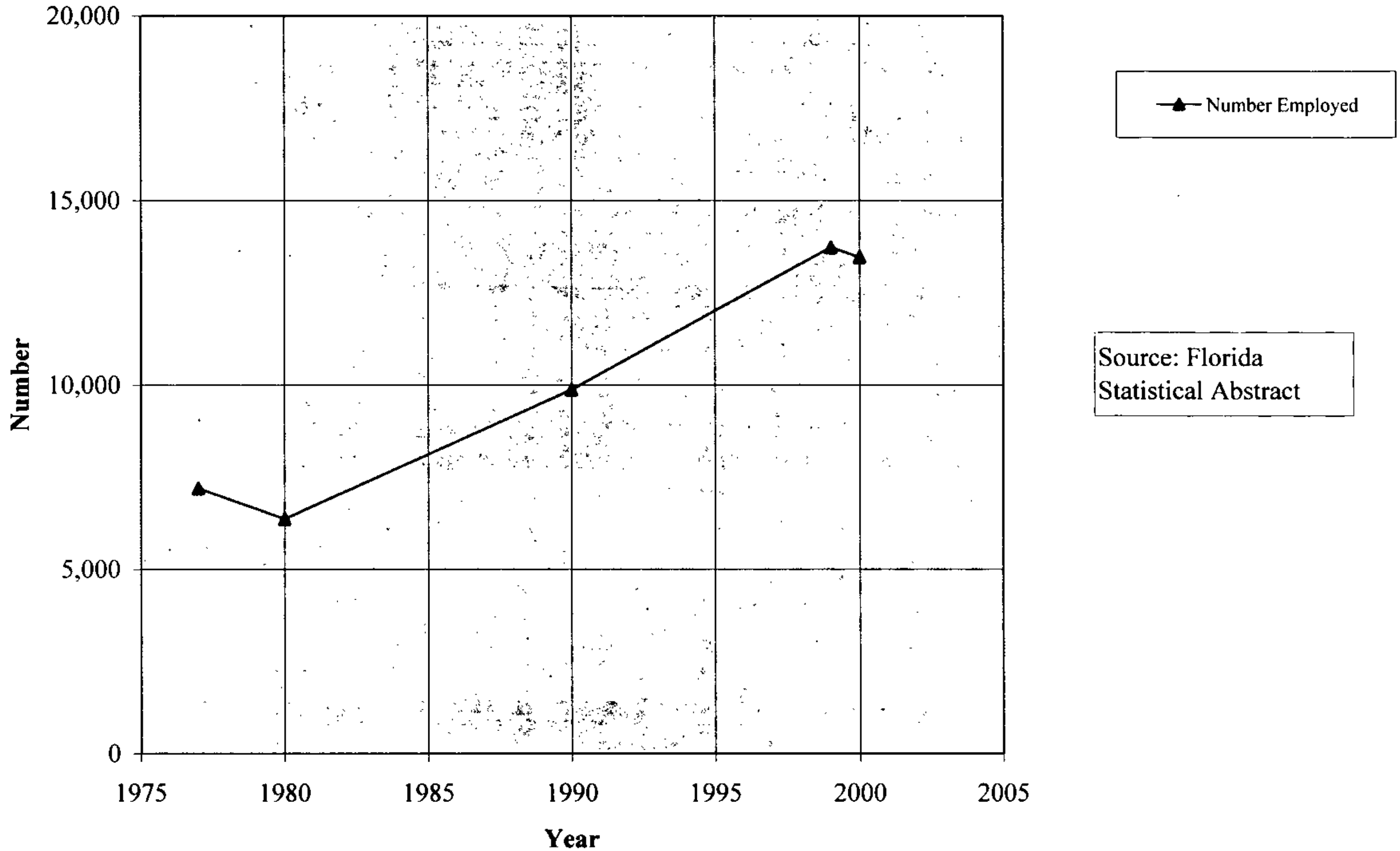


Figure C-4. Hotel & Motel Trends in Hendry County

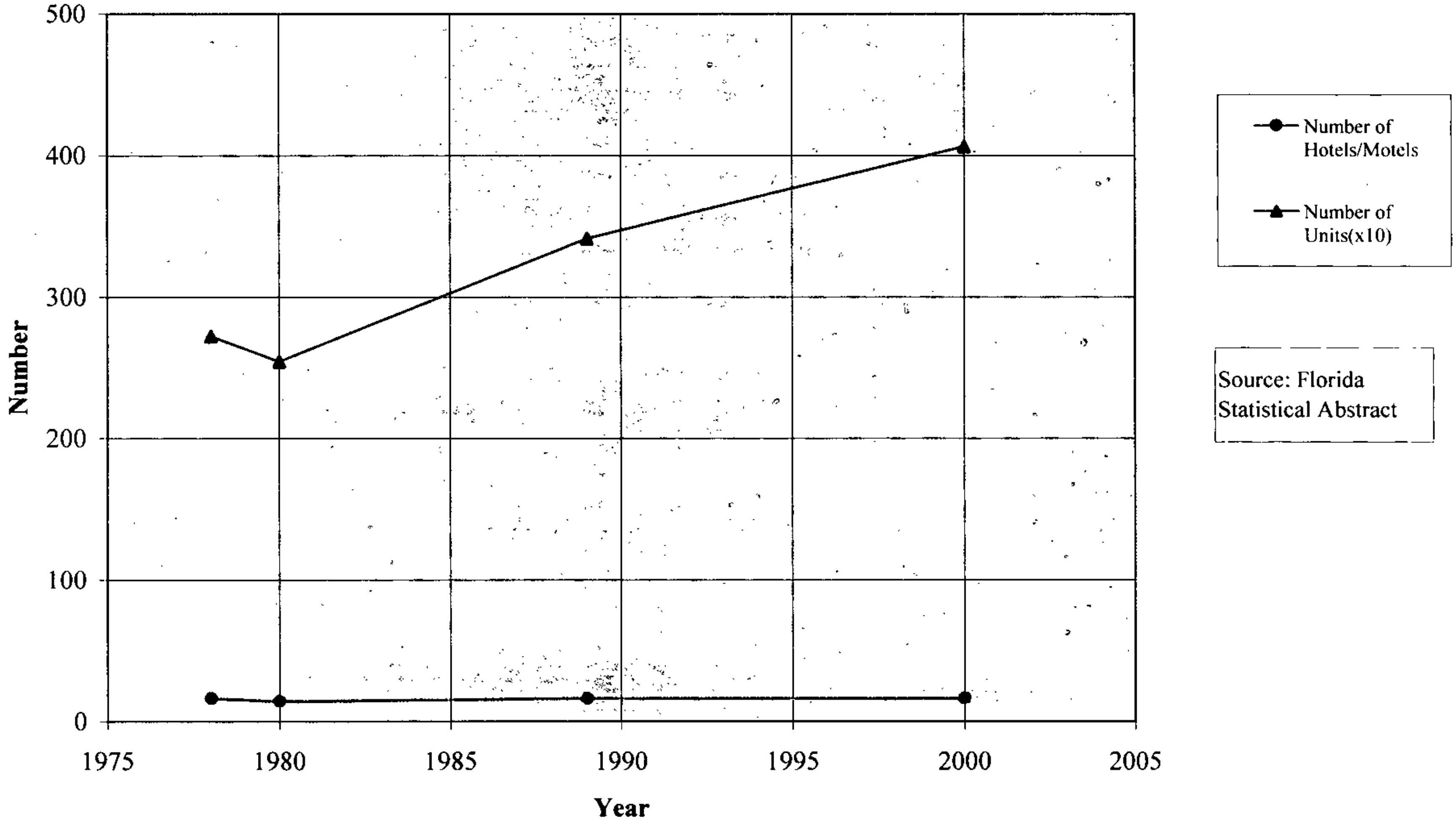
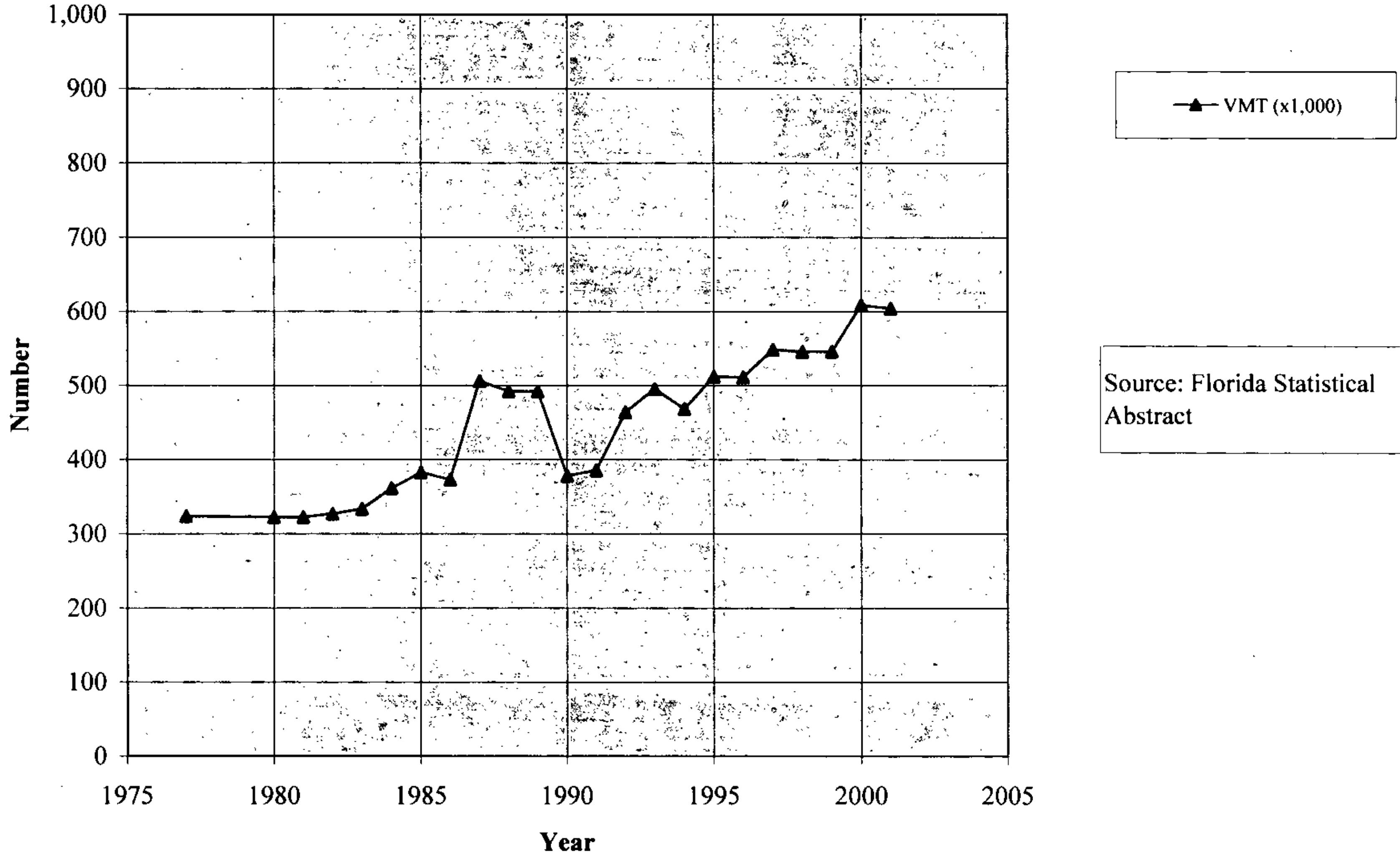
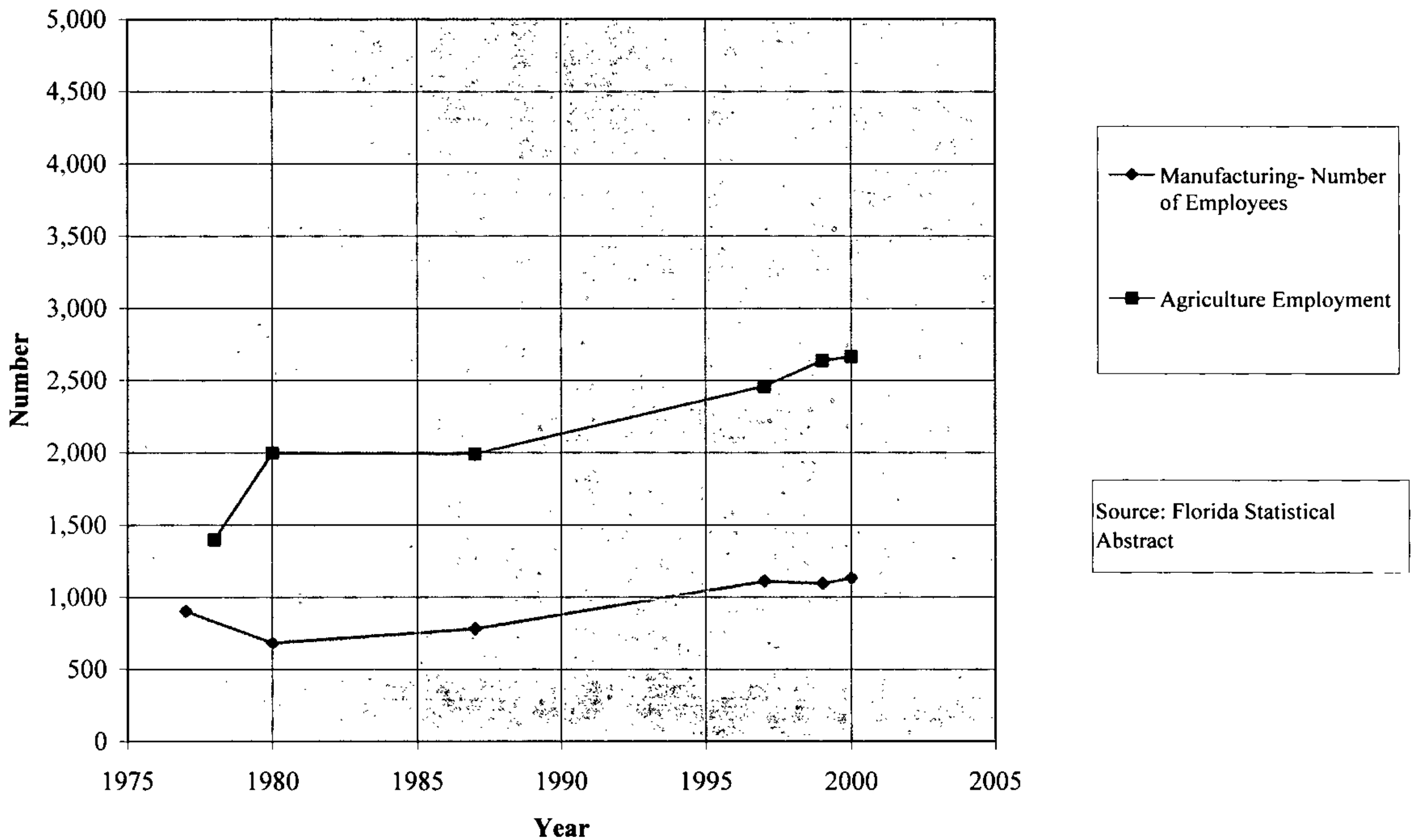


Figure C-5. Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Hendry County



Source: Florida Statistical Abstract

Figure C-6. Manufacturing and Agriculture Trends in Hendry County



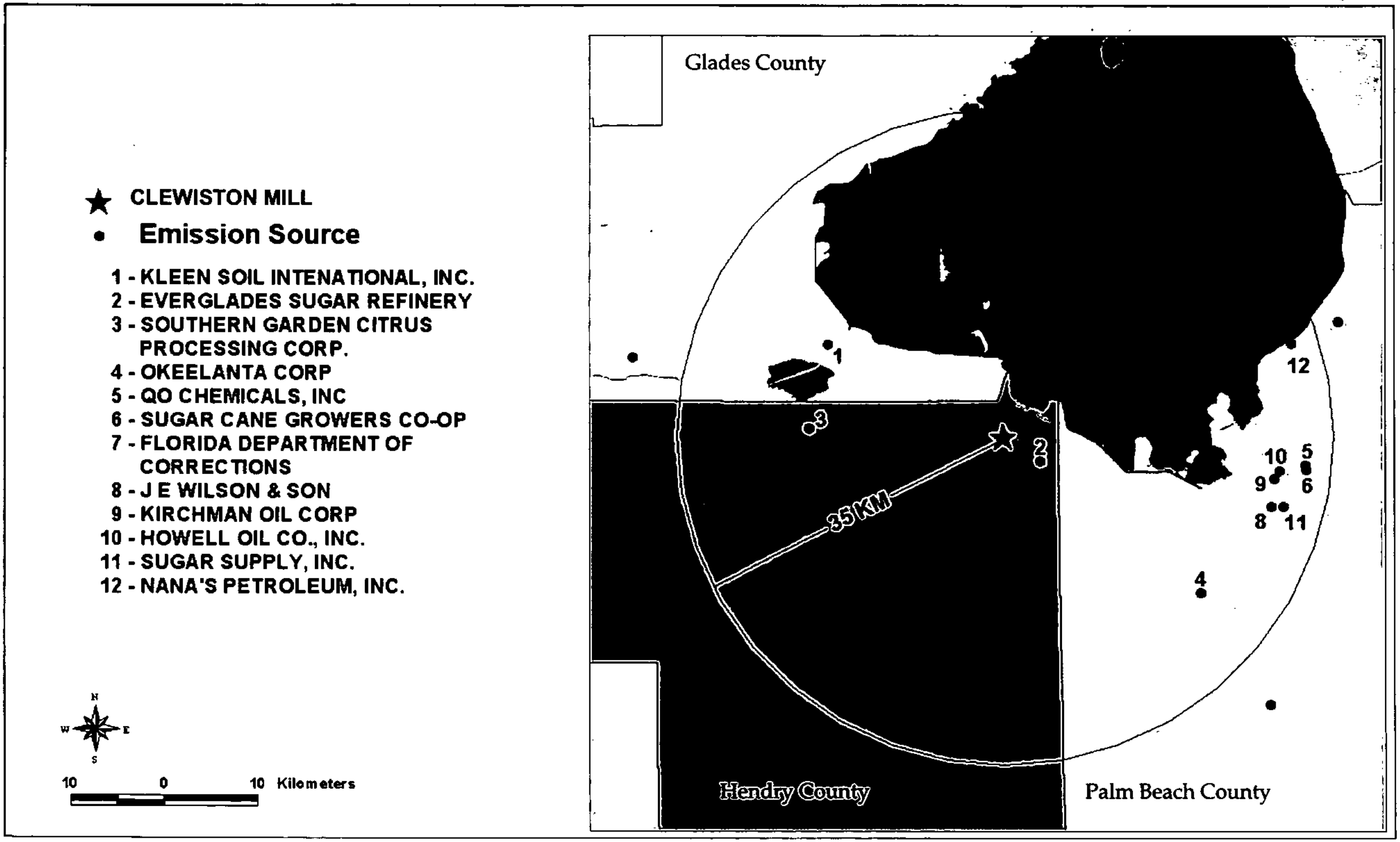


Figure C-7
Nearby Emission Sources

Golder Associates

Figure C-8. Mobile Source Emissions (Tons per Day) of CO, VOC, and NOx in Hendry County

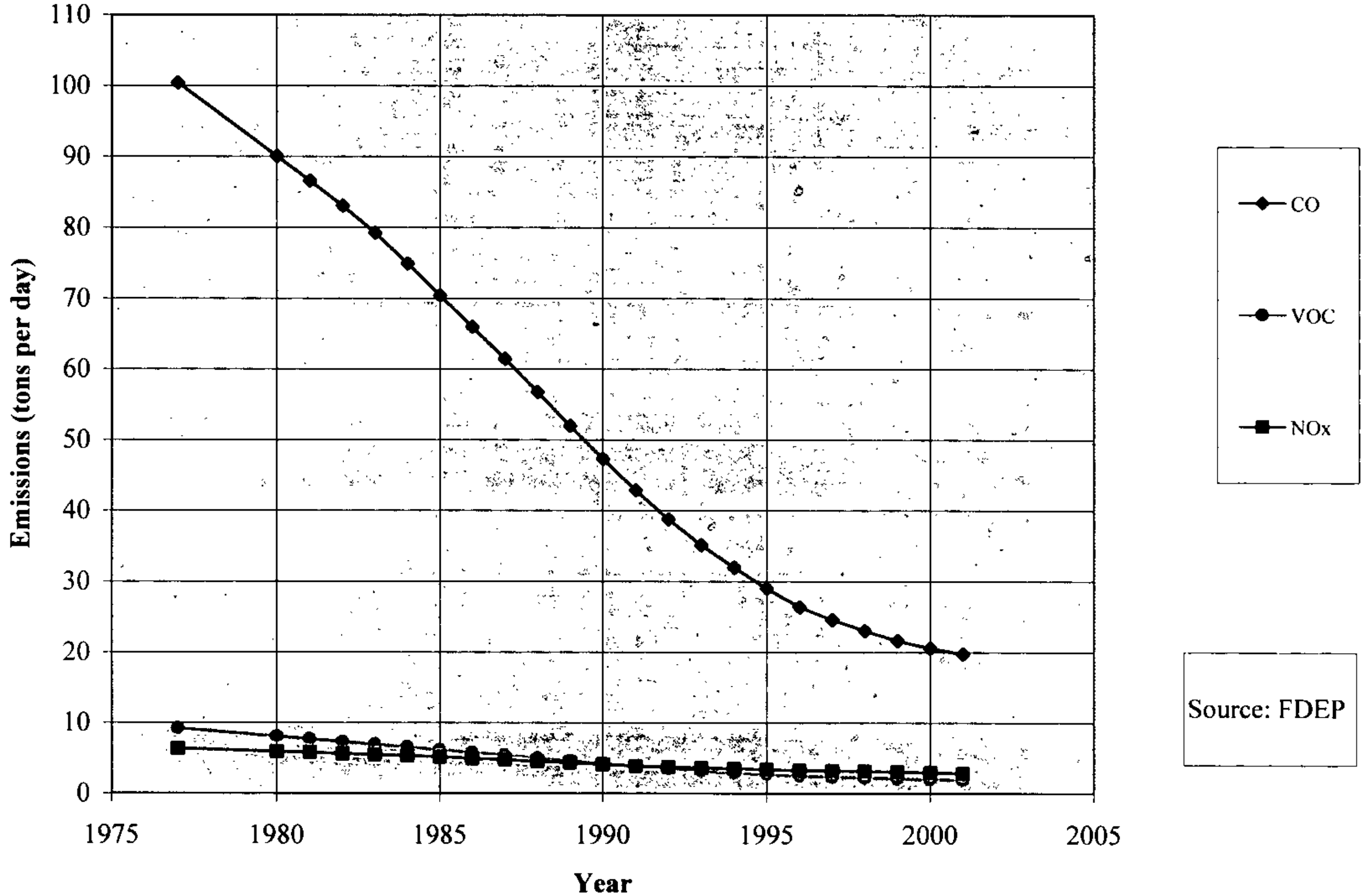


Figure C-9. Measured Annual Average Sulfur Dioxide Concentrations from 1977 to 2002- Palm Beach County

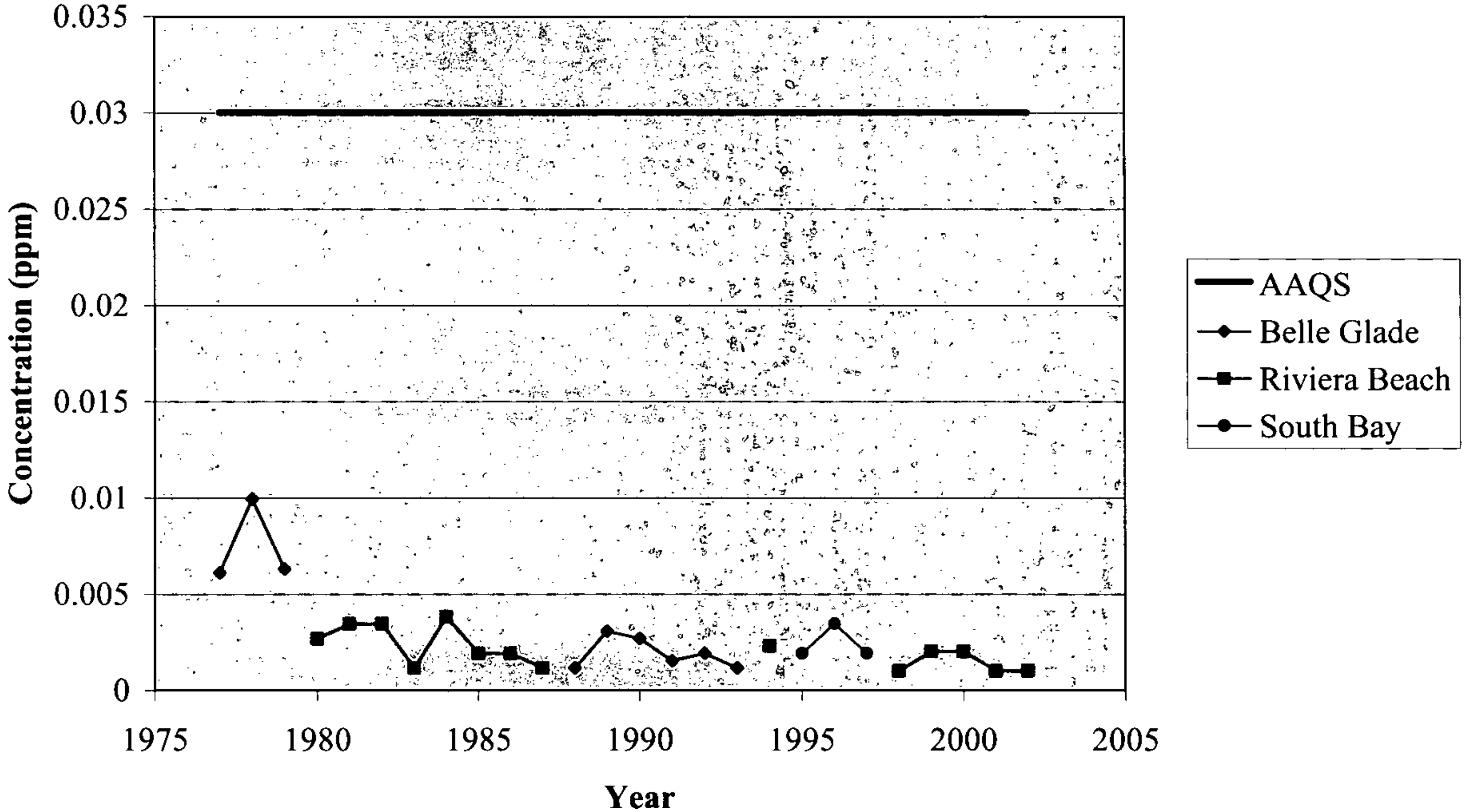


Figure C-10. Measured 24-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) from 1977 to 2002- Palm Beach County

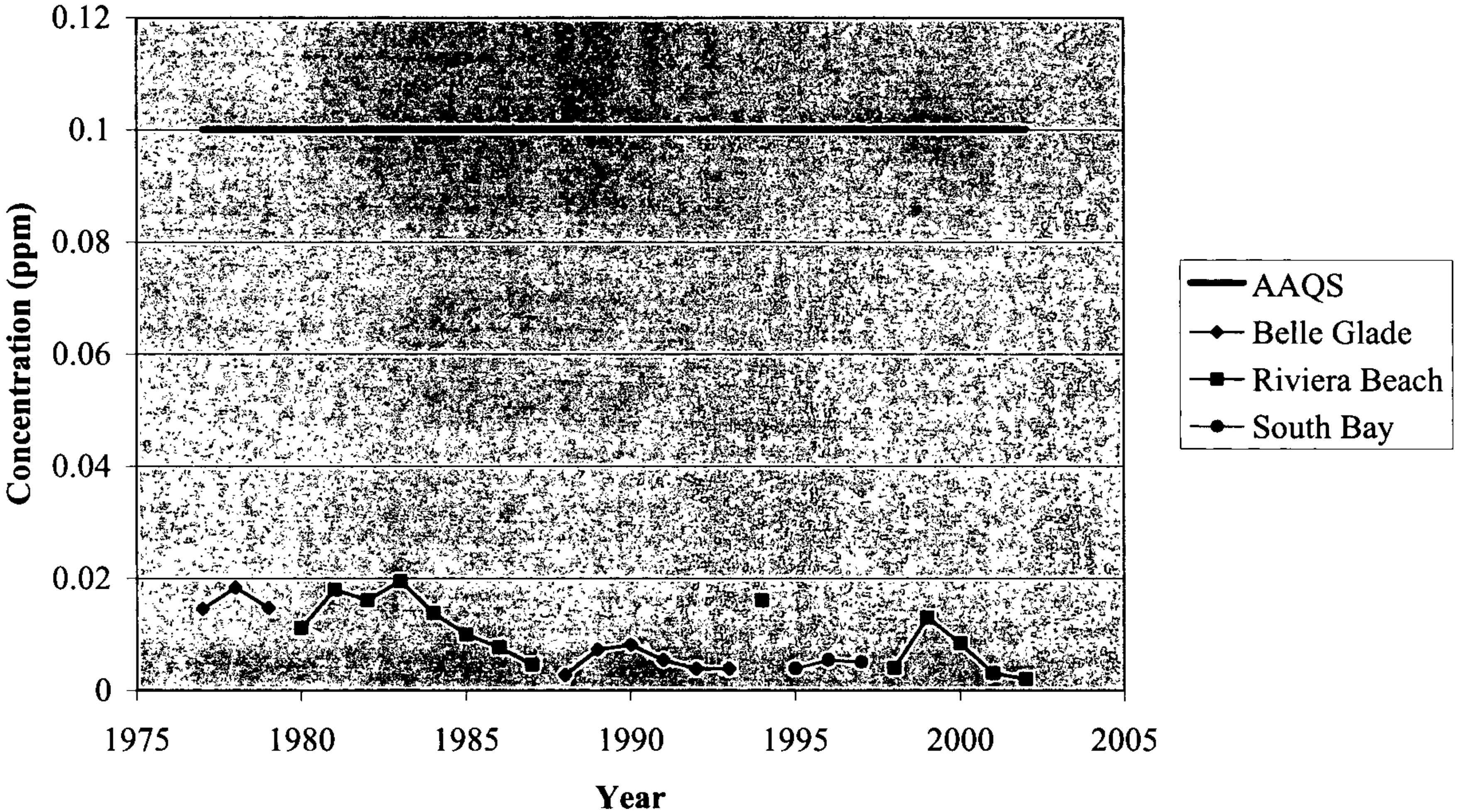


Figure C-11. Measured 3-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) from 1977 to 2002- Palm Beach County

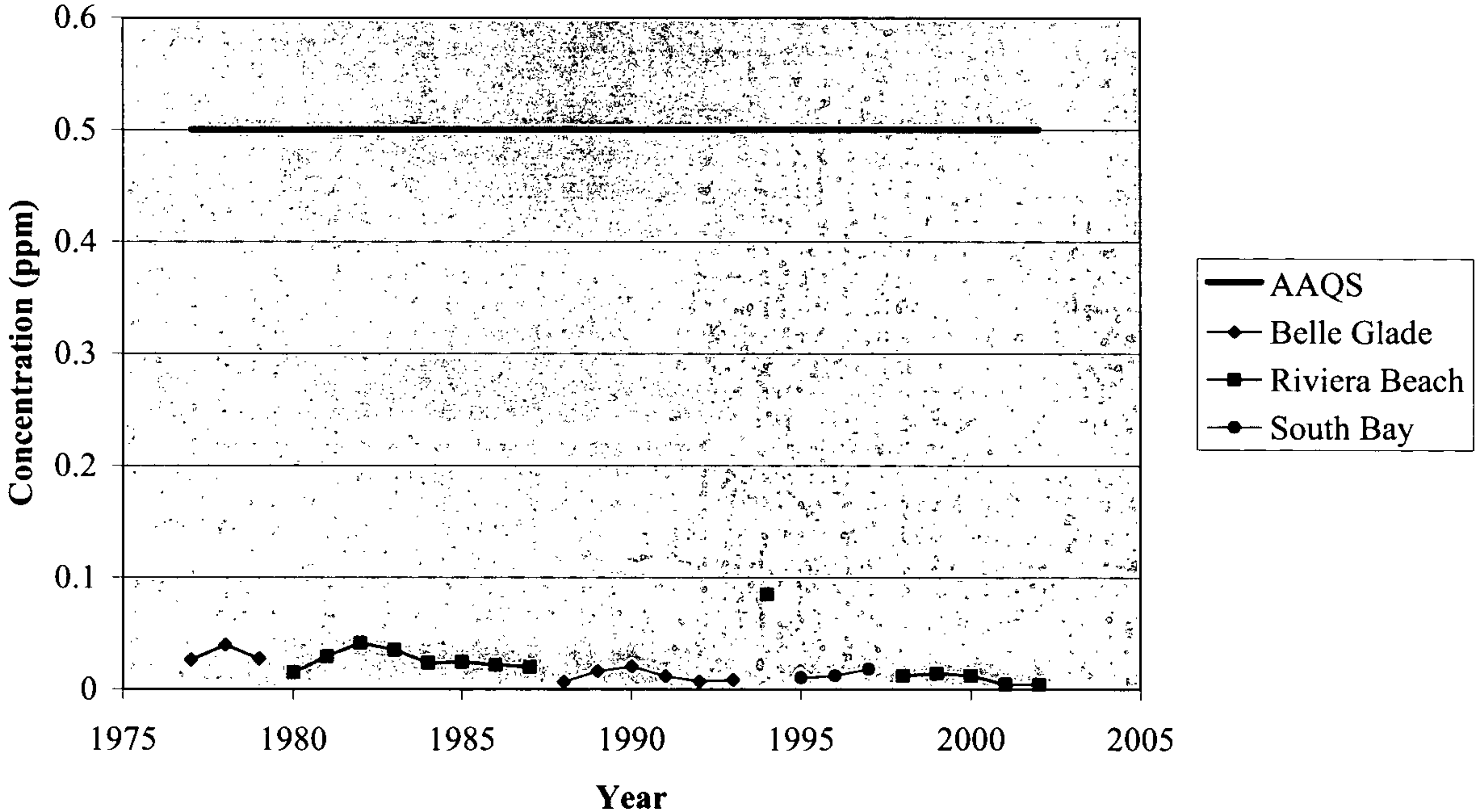


Figure C-12. Measured Annual Average PM10 Concentrations and TSP Concentrations in Hendry and Palm Beach County

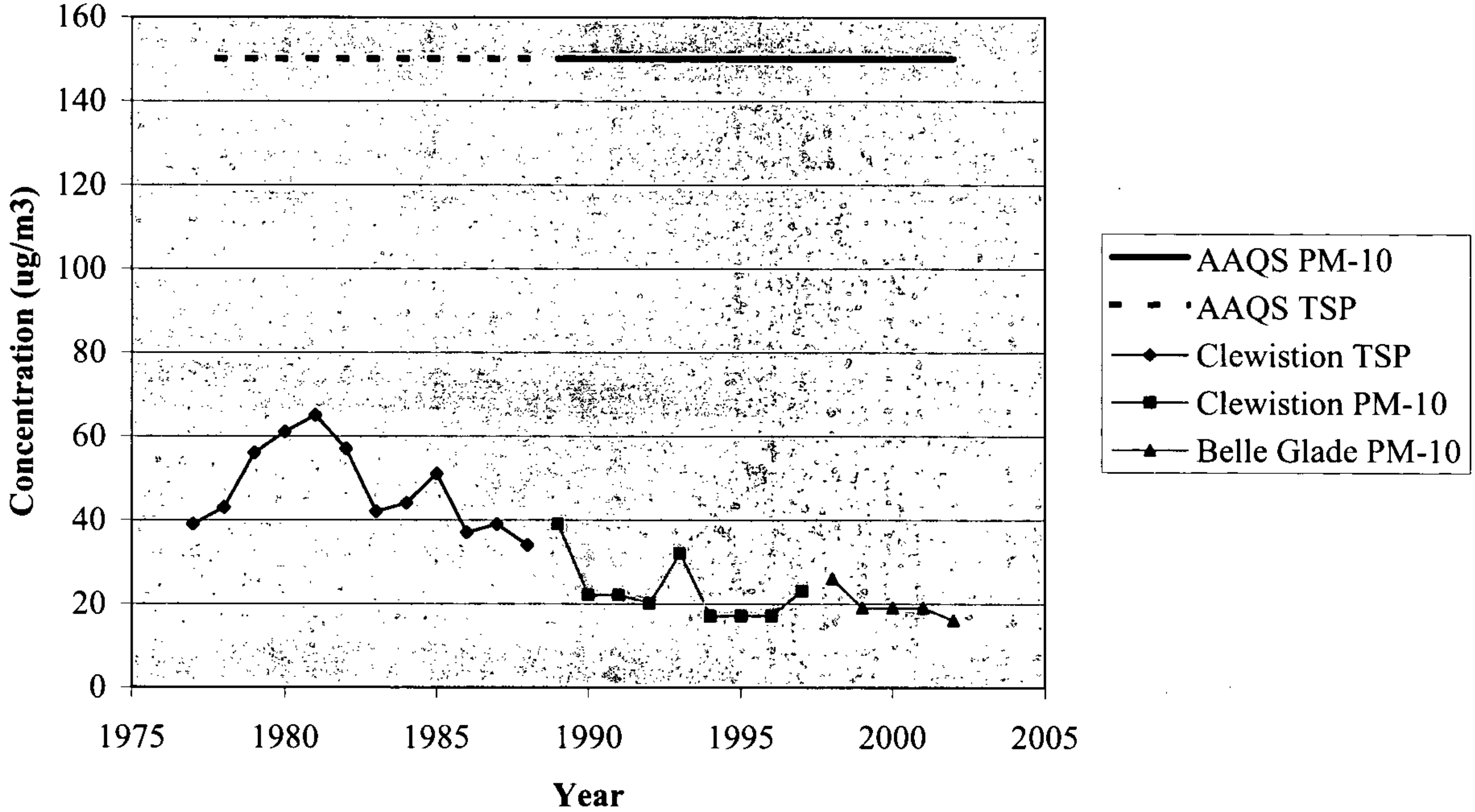


Figure C-13. Measured 24-Hour Average PM10 Concentrations and TSP Concentrations (2nd Highest Values) in Hendry and Palm Beach County

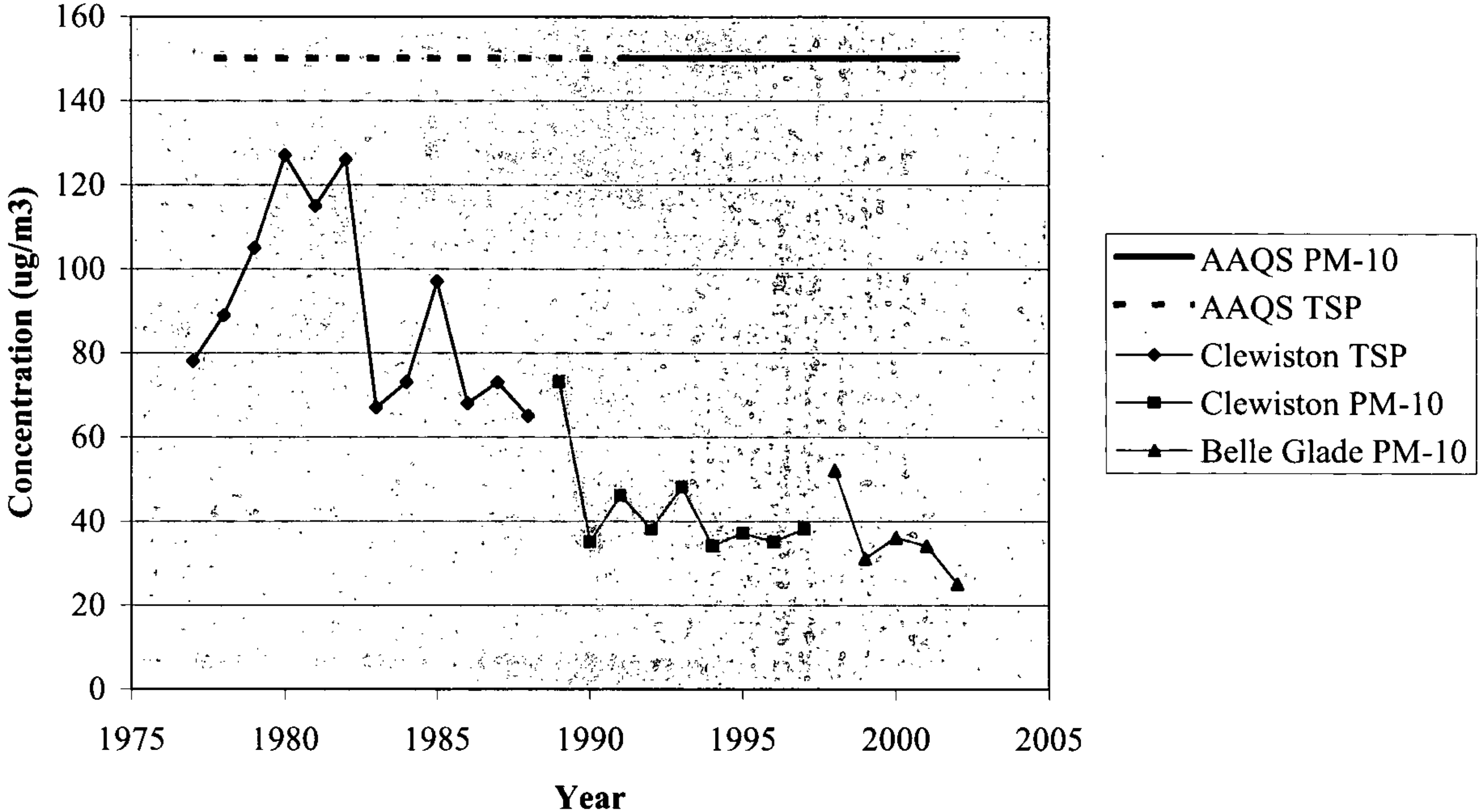


Figure C-14. Measured Annual Average Nitrogen Dioxide Concentrations in Palm Beach County

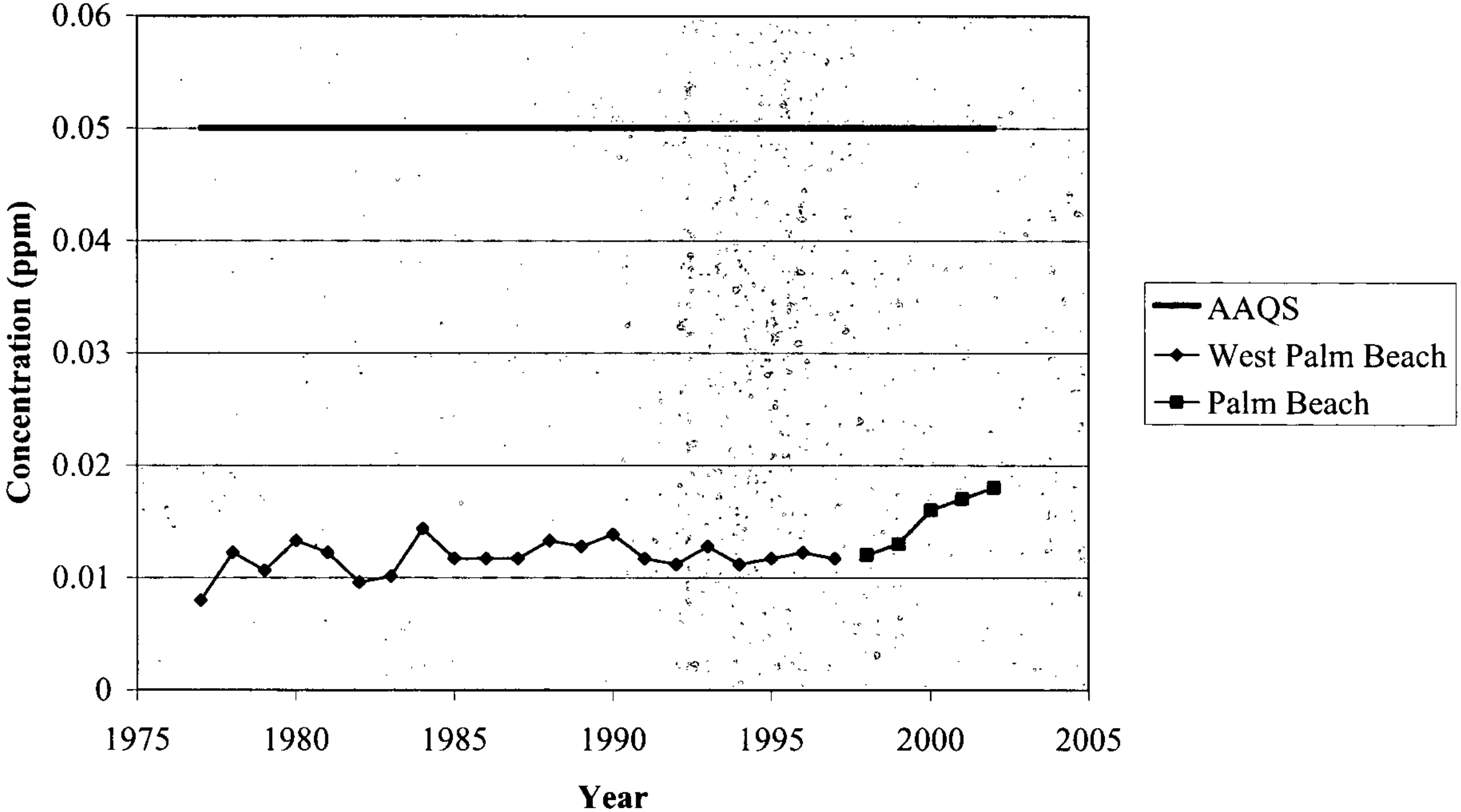


Figure C-15. Measured 1-Hour Average Ozone Concentrations (2nd Highest Values) in Palm Beach County

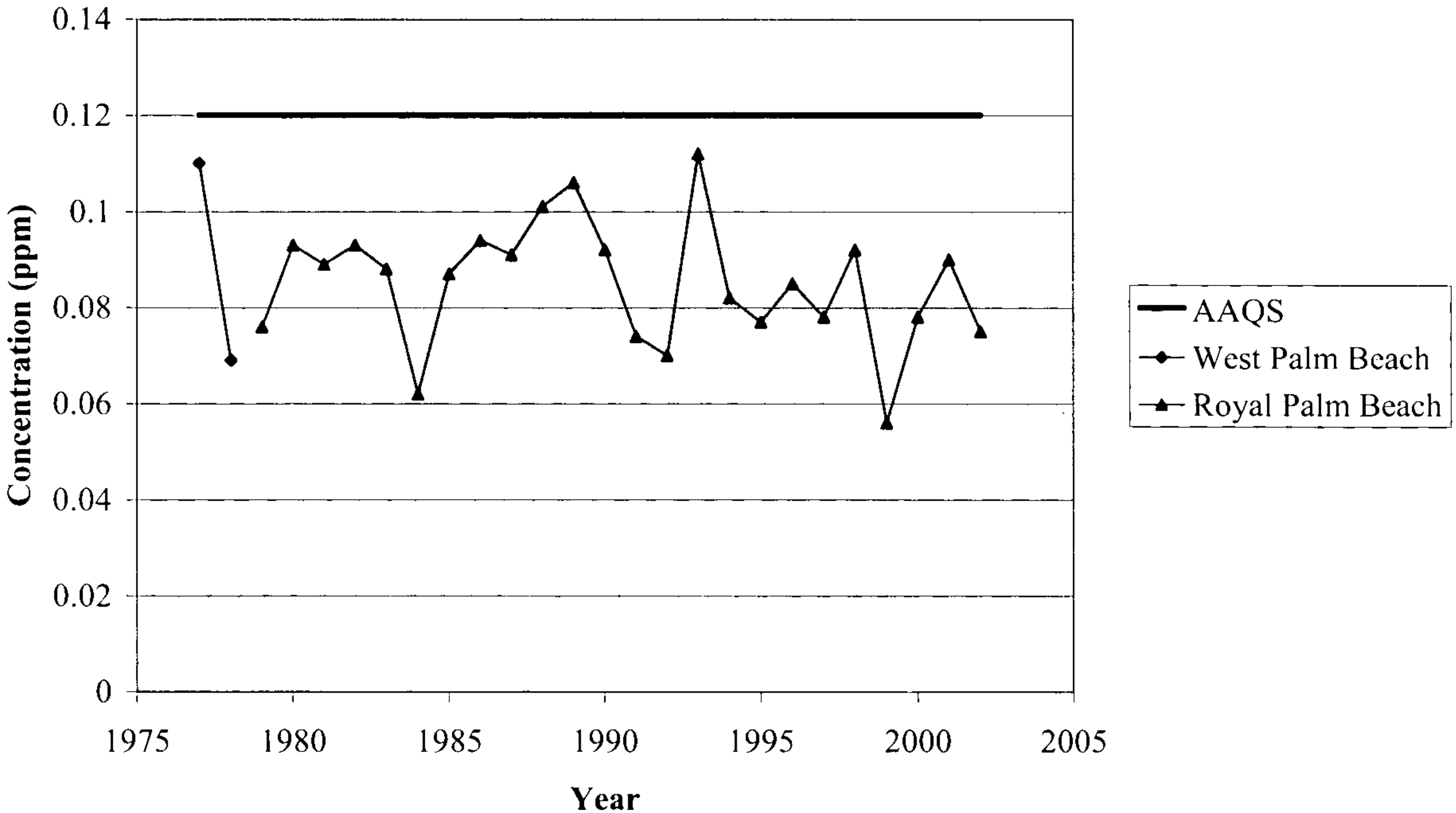
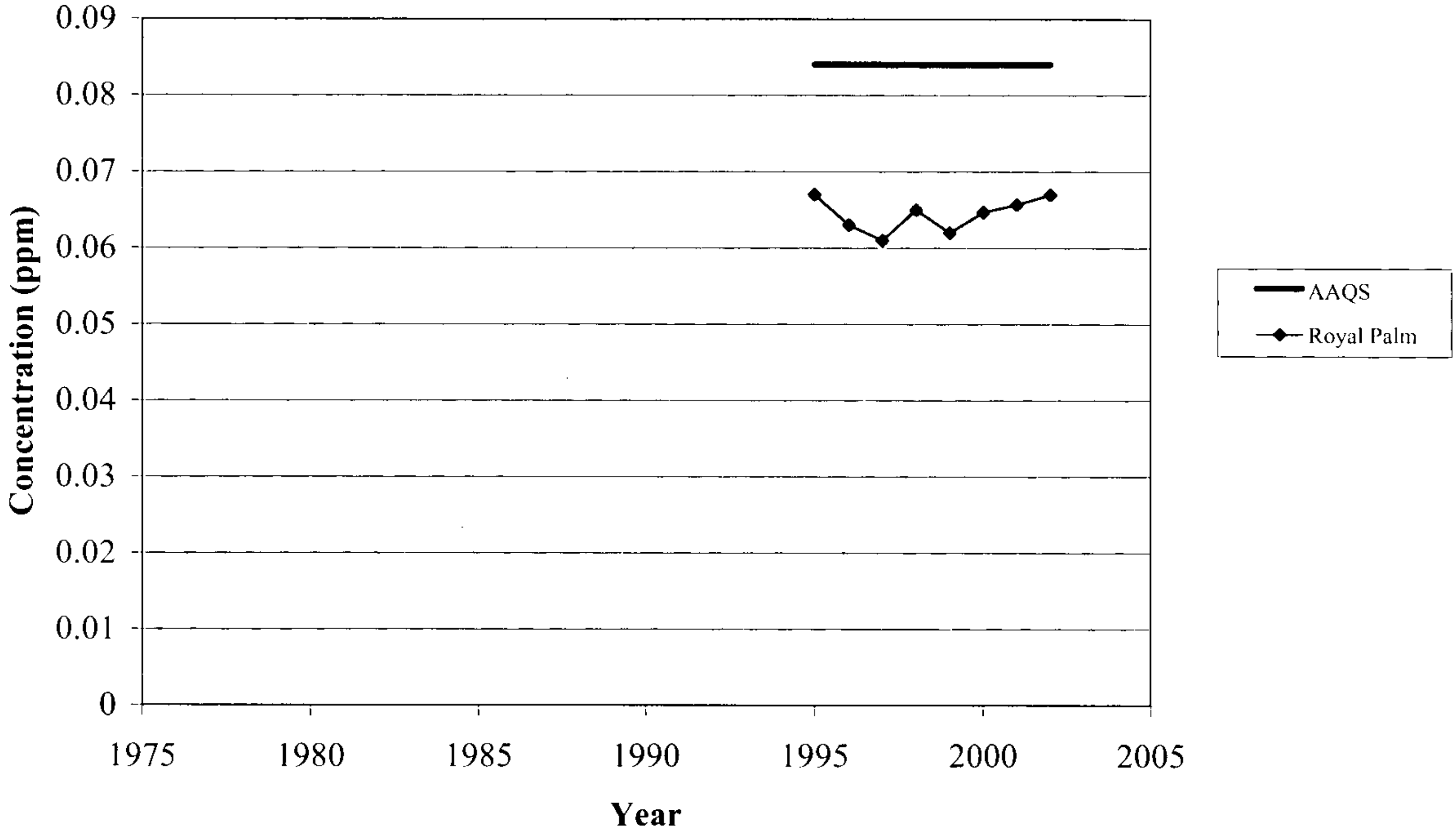


Figure C-16 Measured 8-Hour Average Ozone Concentrations (3-Year Average of the 4th Highest Values) in Palm Beach County



United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

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May 1, 2003

N3615 (2350)

A.A. Linero, P.E., Administrator
Department for Environmental Protection
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

We have reviewed the U.S. Sugar Corporation's (U.S. Sugar) Prevention of Significant Deterioration (PSD) permit application for a modification to their Clewiston Sugar Mill and Refinery in Hendry County, Florida. The refinery is located approximately 102 kilometers north of Everglades National Park (NP), a Class I air quality area administered by the National Park Service (NPS). U.S. Sugar proposes to add a new 550,000 lb/hour, bagasse, natural gas, and oil-fired steam boiler to the existing Clewiston Sugar Mill and Refinery. Proposed addition of this boiler will cause emissions of nitrogen oxides (NO_x) to increase by 744 tons per year (TPY), sulfur dioxide to increase by 203 TPY, volatile organic compounds to increase by 203 TPY, and particulate matter to increase by 88 TPY.

Based on our review of the permit application, we do not anticipate that emission increases from the proposed modification will have a significant impact on sensitive resources at the Everglades NP. However, we do have the following comments concerning the Best Available Control Technology analysis section.

Best Available Control Technology (BACT)

Particulate Matter: U.S. Sugar proposes an electrostatic precipitator (ESP) at an emission rate of 0.026 lb/mmBtu. We agree with the choice of an ESP and with the proposed emission rate.

Nitrogen Oxides: U.S. Sugar concluded that over-fire air and "good combustion practices" represent BACT at an average emission rate of 0.22 lb/mmBtu. In its 1999 application to increase the permitted operating hours of its bagasse and #6 oil-fired Boiler #4, U.S. Sugar concluded that "good combustion practices" represent BACT because they were achieving an average emission rate of 0.08 lb/mmBtu. We believe that a new boiler should be able to control NO_x emissions to levels no greater than demonstrated by boiler #4 burning the same fuel (i.e., 0.08 lb/mmBtu).

U.S. Sugar rejected Selective Non-catalytic Reduction (SNCR) based upon a cost-effectiveness of $1400 per ton of NO_x removed. We suggest that $1400/ton may be economically feasible on the basis that many states use a cost-effectiveness threshold of $2000-$5000/ton for NO_x.

Sulfur Dioxide: U.S. Sugar proposed firing of 0.05% sulfur fuel oil as BACT. By 2006, the Environmental Protection Agency (EPA) will require that 80% of all on-road diesel fuel meet a sulfur limit of 0.01%, and by 2010, 100% of all on-road diesel fuel must meet that limit. Although those EPA limits will not directly apply to fuel oil burned in a boiler such as that proposed by U.S. Sugar, it is clear that 0.01% sulfur oil will be readily available by 2006. We are aware of at least four proposed combustion turbine projects in Virginia (Tenaska—Bear Garden, Tenaska-Fluvanna Co., Dynegy—Chickahominy Power, and ODEC-Louisa Co.) and one facility in Georgia (Southern Co.-Macintosh) that have proposed the use of fuel oil limited to 0.01% sulfur. U.S. Sugar should address the feasibility of using such a lower sulfur fuel oil in its BACT analysis. We request U.S. Sugar be required to purchase and use 0.01% sulfur oil no later than 2006.

In summary, we agree that ESP is BACT for particulate matter emissions. U.S. Sugar should lower their NO_x limit to reflect actual capabilities of the new boiler; they should achieve emissions levels of 0.08 lb/mmBtu, no greater than emission levels demonstrated by boiler #4. U.S. Sugar should also consider the use of lower sulfur oil.

Thank you for involving us in the review of the PSD permit application for the modification to U.S Sugar's Clewiston Sugar Mill and Refinery. Please do not hesitate to contact me at (303) 969-2817 regarding future air quality matters involving the NPS.

Sincerely,

Darwin W. Morse
Environmental Protection Specialist
Policy, Planning and Permit Review Branch

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 2, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: **Request for Additional Modeling Information**
Project No. 0510003-021-AC (PSD-FL-333)
Clewiston Sugar Mill and Refinery
Proposed New Boiler 8

Dear Mr. Raiola:

On April 2, 2003, the Department received your application and sufficient fee for an air permit to construct a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to support operations of the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The modeling information submitted with the application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations or revised modeling, please submit the new calculations or revised modeling, assumptions, reference material and appropriate revised pages of the application form.

1. The building information contained in the facility plot plan Attachment UC-FI-C2, Page 3 and the BPIP building, structure data and location data contained in the figures and information in Appendix K do not appear to match. Please indicate which of these is correct. In addition, please update the application with the correct, detailed building structure information used in the modeling to determine downwash impacts. This information should include building dimensions for all buildings used in the modeling analyses. In addition, please provide a detailed plot plan to scale of the facility showing the exact location of the modeling origin in meters and the location from this modeling origin of each building and stack. All stacks and buildings should be labeled. In addition, a grid with 50 meter spacing should be overlaid over this plot plan so that the information on the plot plan can be easily correlated with the information in the BPIP files.
2. Rule 62-212.400(5)(h) 5, F.A.C. requires the applicant to provide information relating to the air quality impact of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Please provide this information. The additional impacts section 7.0 does not adequately address this requirement.
3. <u>Comments from EPA or NPS</u>: The Department has provided copies of the PSD application for comment to EPA Region 4 and the National Park Service. If we receive specific comments, we will forward for your response.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-8986.

Sincerely,

Cleveland G. Holladay
New Source Review Section

cc: Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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1. Article Addressed to:

Mr. William A. Raiola
Vice President of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

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Clewiston, FL 33440

PS Form 3800, January 2001 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 25, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: **Request for Additional Information**
Project No. 0510003-021-AC (PSD-FL-333)
Clewiston Sugar Mill and Refinery
Proposed New Boiler 8

Dear Mr. Raiola:

On April 2, 2003, the Department received your application and sufficient fee for an air permit to construct a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to support operations of the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Boiler 8: Boiler 8 will be a membrane wall boiler with balanced draft stoker, overfire air, rotating feeders, and pneumatic spreaders having the following specifications:

   - Steam Production: 550,000 lb/hour, 1-hour max. (500,000 lb/hour, 24-hour max.)
   - Steam Parameters: 600 psig @ 750° F (enthalpy = 1379 Btu/lb)
   - Feedwater Parameters: 800 psig @ 250° F (enthalpy = 218 Btu/lb)
   - Heat Input Rate: 1030 MMBtu/hour, 1-hour max. (936 MMBtu/hour, 24-hour max.)
   - Approximate Furnace Volume: 50,520 ft^3 (20,497 Btu/ft^3 heat release rate)
   - Design Thermal Efficiency: 62%
   - Stack Parameters: 13 feet diameter; 199 feet tall
   - Flue Gas: 330° F; 400,000 acfm @ 5.5% O_2 (225,000 dscfm @ 7% O_2)

   Please provide specific details describing how the bagasse feed rate and boiler heat input rate will be determined. Describe the mechanism used to adjust the air-to-fuel ratio. Describe the soot blowing procedures, frequency and the impacts on emissions. The application indicates that the flue gas oxygen content will be approximately 5.5%. What will be the normal operating range for the flue gas oxygen content? Will Boiler 8 be the primary boiler used to support the refinery operation during the milling off season? Will Boilers 7 and 8 normally operate at the same time during the refinery season?

2. Requested Fuels: Boiler 8 will fire the following fuels:

   - Primary Fuel: Bagasse (7.2 MMBtu/ton; 143 tons per hour)
   - Startup/Supplemental Fuel: Distillate oil (0.05% sulfur by wt.; 135 MMBtu/1000 gallons; 4161 gph)
   - Startup/Supplemental Fuel: Natural gas (1000 MMBtu/MMscf; 0.562 MMscf/hour)

Although U.S. Sugar has indicated a desire to fire natural gas as a startup fuel and a supplemental fuel, it does not appear that gas will be available in the Clewiston area within the next two years. Will the gas burners be installed during the initial construction of Boiler 8? A Department air construction permit may only cover the initial period to construct and test the unit in preparation for commercial operation. Does U.S. Sugar wish to pursue natural gas at this time?

3. Requested Capacity Restrictions: The application requests that the annual capacity factor for Boiler 8 be restricted to 75% by limiting the annual steam production to 3.6135 x 10^{+09} pounds per year (equivalent to 6,767,100 MMBtu/year). With the shutdown of Boiler 3, this allows the project to net out of PSD review for CO emissions. Fossil fuels will be limited to an annual capacity factor of less than 10%. This limit avoids certain requirements of NSPS Subpart Db. Please understand that a future relaxation of these restrictions will require a PSD applicability review as if the boiler were not yet constructed and may trigger other requirements.

4. CO and VOC Emissions: As mentioned previously, the project nets out of PSD review for CO emissions due to the restriction on annual capacity and the proposed CO standard of 0.38 lb/MMBtu, which is based on a 12-month rolling average. The application indicates that this standard was calculated by correcting to a flow rate of 225,000 dscfm @ 7% O_2 from the design flow rate of 203,180 dscfm @ 5.5% O_2 (which represents "actual" conditions). At 5.5% O_2, the hourly emission rate would be 321.5 lb/hour or 0.34 lb/MMBtu based on a 24-hour average. Please explain the correction to 7% O_2 before calculation of the emission rate based on heat input.

   The proposed EPA MACT standard for CO is 400 ppmvd @ 3% O_2. Based on the method provided in the application, the flow rate corrected to the MACT units would be 174,961 dscfm @ 3% O_2. The mass emission rate would be 277 lb/hour and the equivalent 24-hour emission rate based on heat input would be 0.30 lb/MMBtu. According to the proposed boiler MACT, Boiler 8 will be required to meet standards upon startup if the rule is final or no later than the date the MACT becomes final. Therefore, the Department intends to require that the new boiler be designed to achieve the proposed MACT CO work practice standard of 400 ppmvd @ 3% O_2 based on a 24-hour average. Until the MACT becomes final, this will likely be established as a "target level" of emissions that indicates good combustion practices are being employed. Please comment.

   The proposed VOC limit is 0.06 lb/MMBtu. The test data available for similar units indicates lower levels may be achievable. The application list VOC emission test data for Clewiston Boiler 7 and New Hope Power Boilers 1-3. VOC test data for Clewiston Boiler 7 shows the highest tested rate to be 0.114 lb/MMBtu with the next highest rate at 0.015 lb/MMBtu. The Department notes that the CO emission rate was 0.392 lb/MMBtu for the highest VOC rate and 0.287 lb/MMBtu for the next highest rate, which may indicate that the unit was not operating under the best combustion conditions. In addition, it is unclear whether the VOC emission rate includes methane or ethane emissions, which are not regulated as VOC. Similarly, the highest tested VOC emission rate for New Hope Power Boilers 1-3 was 0.02 lb/MMBtu. Based on this information, the Department is considering a VOC standard of 0.03 lb/MMBtu based on good combustion practices. Please comment.

   CO CEMS: The Department intends to require a continuous emissions monitor to measure and record CO emissions.

5. Particulate Matter Controls

   Wet Cyclone: Please provide a description, a conceptual diagram and additional design details of the wet cyclone scrubber. What will be the approximate water injection rate? Will this rate change subject to load conditions? Please provide the results of any inlet/outlet testing performed for the similar scrubber installed on Boiler 7.

   ESP: The application indicates that the vendor has not yet been selected. Which vendors are being considered for the project? Will this be a dry, negative corona plate ESP? Please provide reasonable assurance that the proposed ESP can achieve the propose emission standard. (For example, preliminary estimates for the following design parameters: collection plate area (ft^2); specific collection area (SCA, ft^2 per 1000 ft^3/minute); length and height of each field (ft); aspect ratio (L/H); particle migration velocity (w); field voltage; current, and sparking rate.) Will there be one electrical transformer-rectifier (T-R) set for each of the nine fields? Please describe the rapping system used to remove collected ash from the ESP plates including storage and handling. During startup, identify parameters that indicate the proper time to energize the ESP. Approximately how long is it from initial fuel firing to energizing the ESP?

COMS: Provide a justification for the Alternate Sampling Procedure (ASP) requested in lieu of the continuous opacity monitor, which is required by NSPS Subpart Db. The Department will forward your request to EPA Region 4 for a determination, as this is a federal requirement. Please note that the Department may require a continuous opacity monitor as part of a continuous demonstration of compliance with the BACT permit limits.

6. <u>Sulfur Dioxide and Sulfuric Acid Mist Controls</u>: The Department is considering an SO_2 standard of 0.05 lb/MMBtu for all combinations of fuel firing. This emission level reflects previous BACT determinations for a variety of combustion processes that specify ultra-low sulfur distillate oil (0.05% sulfur by weight), which is also equivalent to 0.05 lb/MMBtu of heat input. Based on available information for bagasse boilers, this is achievable for the proposed unit. Notwithstanding any underlying state or federal requirements to install an SO_2 CEMS, the Department is considering the following for demonstrating compliance: quarterly SO_2 stack testing for the first year; monthly sampling and analysis of bagasse for fuel sulfur content for first year; if first year shows satisfactory compliance the stack testing may be reduced to annual tests and bagasse sampling to quarterly analysis. Please comment.

7. <u>Controls for Nitrogen Oxides</u>

   The proposed NOx standard of 0.22 lb/MMBtu based on good combustion practices does not reflect the maximum level of control for similar solid fuel fired boilers. Even at a lower level, it is likely that an add-on control technology will be cost-effective.

   SCR: The Department is not convinced that SCR is technically infeasible due to poisoning issues. There are many coal-fired boilers in the U.S. and there are many municipal waste combustors in Europe that successfully employ SCR. Please provide information to support the impacts of catalyst poisoning. Compare and comment on expected poison levels from firing bagasse with that of firing coal and/or municipal solid waste. In addition, obtain at least one cost quote specifically for this project from an SCR vendor and submit an economic cost analysis. Provide to the Department the information given to the vendor as the basis for the design.

   SNCR: The Department is aware of several wood fired boilers, wood/bagasse boilers, and wood/municipal waste combustors that successfully employ SNCR to reduce NOx emissions by at least 40%. It is clearly a cost effective technique and there are no apparent technical reasons for rejecting this technology. Please provide any additional information on SNCR you would like the Department to consider in making a BACT determination.

   NOx CEMS: Regardless of the technology employed, the Department intends to require a continuous emissions monitoring system for NOx emissions.

8. <u>Boiler MACT</u>: On January 13, 2003, EPA proposed Subpart DDDDD, which establishes maximum achievable control technology (MACT) requirements for hazardous air pollutants (HAPs) from industrial, commercial, and institutional boilers and process heaters. The application indicates that Boiler 8 is not expected to be a major source of HAP emissions and will not be subject to the MACT regulations for new boilers. If the proposed rule becomes final as currently written, the Department believes that Boiler 8 will be subject to the final MACT standards either: upon startup (if the rule becomes final before startup) or when the rule becomes final (if start up occurs before the rule becomes final). The Department intends to require that Boiler 8 be designed to achieve the proposed standards. Please comment.

9. Bagasse Handling System: For any new dust collectors being added as part of this project, please provide the vendor's predicted outlet emission rate (grains/acf), flow rate range (acfm), and control efficiency.
10. Refinery Operations: Is U.S. Sugar requesting a relaxation of any operational restrictions or emission standards for existing emission units at the refinery? Please identify any such relaxations and quantify the emissions impacts as necessary.
11. CAM Plan: Please be aware that a CAM plan will be required for each pollutant with potential emission greater than 100 tons per year (CO, NOx, SO_2, and VOC) as part of the Title V application to incorporate the operation of Boiler 8.
12. Air Quality Modeling Review: The Department is currently reviewing the air quality modeling analysis provided in support of the proposed project. Any additional information will be requested on or before May 2, 2003.
13. Comments from EPA or NPS: The Department has provided copies of the PSD application for comment to EPA Region 4 and the National Park Service. If we receive specific comments, we will forward for your response.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner
New Source Review Section

cc: Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation - Clewiston Sugar Mill & Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

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