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August 3, 1999

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RECEIVED
AUG 04 1999
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
New Source Review Section
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Attention: Jeffery F. Koerner, P.E.

RE: Response to Request for Additional Information to Continue Processing a Prevention of Significant Deterioration Permit Application for Increased Operation of Boiler No. 4 and Refinery, DEP File No. 051003-009-AC (PSD-FL-272)

Dear Mr. Koerner:

The purpose of this letter is to respond to your letter to Mr. Murray T. Brinson, Vice President of United States Sugar Corporation, dated July 22, 1999. Your letter requested additional information to continue processing an Air Construction Permit Application to increase operation of Boiler No. 4 and expand the sugar refinery at U.S. Sugar's facility located in Clewiston, Florida. This response is organized in the same manner as your letter cited above:

1. Boiler No. 4 operation will in no way affect the operation of the other combustion units at this facility, since Boiler No. 4 operates independently of these other units. The proposed changes to the refinery may require a small additional steam demand, which will be provided through the increased operation of Boiler No. 4. The increased Boiler No. 4 operation may also allow increased raw sugar production in the sugar mill. Pollutant emissions from the sugar mill potentially include VOC and PM, and although unquantifiable are believed to be relatively minor. Pollutant emissions from the bagasse handling system for Boiler No. 4 include PM and PM_{10}. These emissions could increase due to increased operation of Boiler No. 4. However, PSD review is already triggered for PM, PM_{10}, SO_2, NO_x, CO, and VOC for the project, therefore it is not necessary to quantify such emissions changes. Quantifying such emissions would have no effect on the permitting of or regulatory requirements for Boiler No. 4 or the refinery.

2. The maximum production capacities for the sugar packaging and bulk sugar loadout of 2,000 TPD (730,000 TPY) and 2,200 TPD (803,000 TPY), respectively, are correct as stated in the application. The Department's letter incorrectly states the annual throughput for the sugar packaging operation as 720,000 TPY.

3. The oil firing rates for Boiler Nos. 1 through 4 collectively in 1997 and 1998 were 1,523,734 and 536,883 gallons, respectively. The average sulfur content of the No. 6 fuel oil delivered to replace that used by Boiler Nos. 1, 2, and 3 in 1997 and 1998 was 2.28 and 2.42 percent, respectively. The average sulfur content of the No. 6 fuel oil delivered to replace that used by Boiler No. 4 in both 1997 and 1998 was 1.5%. The sulfur contents

provided are only for the fuel oil delivered in 1997 and 1998 and may not reflect the sulfur content of the actual oil fired in the boilers because the sulfur content of the fuel oil in the tank at the beginning of the year is unknown.

During the 1998-1999 crop season, fuel oil containing no more than 1.5% sulfur was replaced periodically throughout the crop season, i.e., many fuel oil shipments were received in approximately 6,000 gallon deliveries.

4. The primary reason that fuel oil with a 0.5% or lower sulfur content cannot be fired in Boiler No. 4 is that Boiler No. 4 is not physically capable of burning such fuel. Boiler No. 4 currently fires No. 6 fuel oil, and firing of No. 2 distillate oil would require a completely new and separate oil firing system, including burners, combustion air system, piping, fuel tank, and control system. It is also noted that the mixing of No. 6 fuel oil and No. 2 fuel oil in a common tank cannot be performed without a blending station.

   Fuel oil with 0.05% sulfur may be appropriate for a new boiler, where such fuel can be designed into the system from the start, but is not appropriate for an existing boiler equipped to burn No. 6 fuel oil. Therefore, it is requested that the current permit condition requiring the replacement of 1.5% sulfur fuel oil in the common plant fuel tank be determined as BACT.

5. Table 2-1, Note 3 indicates 40% SO_2 removal because this is the basis for the current 0.166 lb/MMBtu SO_2 limit for Boiler No. 4. Table 6-3, Note 6 states 75% SO_2 removal was utilized for Boiler Nos. 1-3 because this is what was used in the SO_2 modeling analysis. In regards to SO_2 removal in bagasse boilers with wet scrubbers, there is ample data to demonstrate that SO_2 removals normally exceed 90% without any control of pH on the scrubbers. Therefore, the 75% SO_2 removal in the scrubbers is a conservative estimate of actual SO_2 emissions, and a reasonable assumption for use in the modeling analysis.

   The National Council for Air and Stream Improvement (NCASI), a research group for the pulp and paper industry, has performed studies which demonstrate the alkaline nature of carbonaceous fuels and the resulting inherent SO_2 removal in boilers burning such fuels. Bagasse boilers are believed to operate in a similar manner.

   Presented in Table A is a compilation of SO_2 tests conducted on boilers at the Clewiston mill. Where specific bagasse analysis data were not available, average heating value and sulfur content of bagasse was used. It is noted that Boiler No. 7 has no wet scrubber, but instead has an ESP control device. For the boilers with wet scrubbers (Boilers 1-4 and 5), overall SO_2 removal efficiency of the boiler/wet scrubber system range from 94.5 to 99.8% and actual SO_2 emissions range from 0.001 to 0.014 lb/MMBtu heat input. For Boiler No. 7, SO_2 removal ranged from 89.3 to 98.8% and emissions ranged from 0.004 to 0.038 lb/MMBtu. Recent testing on the Okeelanta Power cogen facility (which also has an ESP control device) while burning bagasse also resulted in emissions ranging from 0.00 to 0.019 lb/MMBtu, with most measurements being 0.0 lb/MMBtu.

   Thus, inherent SO_2 removal is demonstrated for bagasse boilers without any SO_2 removal device (i.e., not dependent on pH control of the scrubber water).

Please note that a revised Table 6-3 is attached, which corrects a typographical error in the table (16,2001 gallons per 3-hour period corrected to 16,200 gallons per 3-hour period).

6. Table 2-1 and Note 10 have been revised to reflect emissions based on 2.5% sulfur. Since the actual fuel sulfur content in the fuel oil tank is somewhere between 1.5 and 2.5%, the most conservative figure was used. A revised copy of Table 2-1 is attached for your review.

7. In the original permit application, U.S. Sugar requested a maximum steam capacity for Boiler No. 4 of 275,000 lb/hr and a 6-hour average steam capacity of 250,000 lb/hr (refer to Table 2-1). The heat input required to produce 275,000 and 250,000 lb/hr of steam is 633 and 600 MMBtu/hr, respectively. The emission factors used to estimate emissions from Boiler No. 4 are a function of the heat input rate which is a function of the steam rate (the emission rate is directly proportional to the heat rate or the steam rate). Emission rates based on the maximum heat input rate of 633 MMBtu /hr were modeled and the results compared to 1- and 8-hour average CO and 3-hour average SO_2 AAQS and PSD increments. Emission rates based on the 6-hour average heat input rate of 600 MMBtu/hr were modeled and the results compared to AAQS and PSD increments with 24-hour and annual averaging periods. Note that U.S Sugar is now requesting that the 6-hour steam rate and heat input limitations be changed to a 24-hour average. This change does not affect any of the modeling results, as described above.

8. Supportive information documenting the 93% factor for PM_{10} emissions is attached.

9. There are no other sources of fugitive emissions associated with Boiler No. 4 or the sugar refinery, other than the bagasse handling system. All outside bagasse conveyors are enclosed.

10. The pH measurement was specified in the operating permit issued by the District office. We believe that the purpose was solely to collect data. This requirement was not related to any emission limit or other requirement for Boiler No. 4. The typical range for pH is 5 to 8. The facility does not add any alkaline material to adjust the pH. As described above in Item 5, there are a number of bagasse boiler SO_2 tests which demonstrate nearly complete SO_2 removal without the aid of alkaline material.

11. No, the volumetric flow rate is not controlled by a variable speed fan. However, the scrubber water level is maintained using a weir.

12. Pressure drop average is 9.5 inches of water. The current permit is adequate to define the acceptable range of pressure drops for the boiler, i.e., a 1-hour average pressure of at least 90% of the average pressure drop existing during the last compliance test, with the 5-minute pressure drop no less than 75% of the average pressure drop during the compliance test.

13. Boiler No. 4 is not equipped with an oxygen analyzer, and therefore there is no oxygen concentration data available for this boiler.

14. The sugar refinery is a new source and does not have two years of operational data to determine representative actual emissions. In this circumstance, PSD regulations allow the use of allowable emissions as a substitute for actual or baseline emissions in netting

calculations. However, baseline emissions for the sugar refinery were assumed to be zero for purposes of the application.

15. Tables 3-1 and 3-2 for the June 14, 1999 permit modification (051-0003-008-AC) are attached for your review. These tables were submitted to FDEP previously as part of the application to modify the permit.

16. The granular carbon regeneration furnace (GCRF) is a new source. The permit issued for the GCRF does not require that destruction/control efficiency tests for VOC or PM be conducted. However, the current permit for the GCRF does require that compliance testing (not destruction/control efficiency tests) be performed for SO_2. Operating parameters monitored for the scrubber and afterburner on the furnace are not currently monitored, because the permit does not require it.

    On a related issue, the current permit for the GCRF stipulates that the sulfur content of the fuel oil fired in the GCRF be 0.03% or less. This limit is based on information provided by U.S. Sugar in the original permit application and not a regulatory limit (other than in the permit for the GCRF). Boiler No. 7 is permitted to fire No. 2 fuel oil with a sulfur content of 0.05% or less. Currently, the No. 2 fuel oil used to fire the GCRF and Boiler No. 7 is stored in a common tank. Because of the common storage tank for the two sources, U.S. Sugar must purchase 0.03% sulfur fuel oil at greater cost and fire it in the GCRF and Boiler No. 7. Since potential annual SO_2 emissions from the GCRF, would only increase from 2.15 to 3.58 TPY by firing 0.05% sulfur No. 2 fuel oil, U.S. Sugar is requesting that the permit condition limiting the sulfur content of the No. 2 fuel oil fired in the GCRF be changed from 0.03 to 0.05%. Revised permit application pages are attached.

    Additionally, the permit for the GCRF requires that stack testing be performed to demonstrate compliance with the SO_2 emission limit. Given that the only source of sulfur compounds in the exhaust gases from the GCRF is the sulfur in the fuel oil, U.S. Sugar requests that the method of compliance with the SO_2 emission limit be changed from stack testing to documentation of the sulfur content of the fuel oil.

17. As described on page 6-8 of the PSD Report, future operation for Boiler No. 4 was modeled year-around, but current operation for purposes of determining the net project impacts and PSD increment consumption were based on Boiler No. 4 operating only 7 months, since the current permit for the boiler restricts it to operating only during the crop season.

18. Actual maximum 1-hour CO emission rates were based on individual actual test data. Data for Boiler Nos. 1 and 2 were considered together since they are identical boilers. The actual data were used in the modeling analysis for Boiler Nos. 1, 2, and 3 since there are no permitted CO limits for these boilers.

19. The control technologies used in Louisiana to control CO, NO_x, PM, SO_2, and VOC emissions from bagasse fired boilers are virtually identical to those proposed for Boiler No. 4 (i.e., they only have wet scrubbers to control PM emissions). Little information is available on Hawaii sugar mills. Based on the Gilmore Manual, there are currently 6 operating mills. Based on information in EPA's ICCR boiler database, it appears that four of these mills employ have wet scrubbers for PM control. Another facility is known

to be an electrical cogen facility, which burns a variety of fuels, but the control equipment is not known. It is pointed out that the only BACT determinations for bagasse boilers have been issued for boilers in Florida. Sugar beet production does not produce bagasse and therefore any control devices used in this industry would not be directly applicable.

20. An e-mail containing the all of the air quality modeling analyses input and output files will be sent directly to Cleve Holladay of FDEP.

21. Note that supporting documentation was included in the application, in the modeling discussion (refer to discussion beginning on pg. 6-12). We are contacting Stan Krivo at EPA Region IV directly on this matter.

22. Noted. We would like a copy of comments from the National Park Service as soon as possible.

Please also find attached an updated flow diagram of the sugar refining operation.

Thank you for your prompt attention to this matter. This project is critical to U.S. Sugar's upcoming crop season. If you have any questions concerning this information, please call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

D. A. Buff

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

CC: File
EPA
NPS
SD
C. Holladay, BAR

DB/SAM/arz

Enclosures

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

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

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **In-Process Fuel Use; Distillate Oil; General**	
2. Source Classification Code (SCC): **3-90-005-89**	
3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **0.09**	5. Maximum Annual Rate: **788**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **135**	
10. Segment Comment (limit to 200 characters): **Max Annual Rate: 788.4(rounded to 788). Max rates refer to the amount of No. 2 fuel oil burned in the granular carbon regeneration furnace and the afterburner.**	

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

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 0.82 lb/hour 3.6 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:

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

6. Emission Factor:

   Reference: See pt.B,tbl:2-4,2-6

7. Emissions Method Code:

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

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

   See Part B Tables 2-4 and 2-6

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

ATTACHMENT UC-EU1-L2
Fuel Analysis Specification for U.S. Sugar Corporation
Granular Carbon Regeneration Furnace
(Revised 07/31/99)

Fuel Parameter	Very Low Sulfur No. 2 Fuel Oil (a) (0.03% max S)
Density (lb/gal)	6.83
Approximate Heating Value (Btu/lb)	19,766
Approximate Heating Value (Btu/gal)	135,000
Ultimate Analysis (dry basis):	
Carbon	87.3%
Hydrogen	12.6%
Nitrogen	0.006%
Oxygen	0.04%
Sulfur	0.05%
Ash/Inorganic	< 0.01%
Moisture	--

Note: All values represent average fuel characteristics.

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

Table 2-4. Emissions From Granular Carbon Regeneration Furnace, USSC Clewiston Mill Expansion (Revised 07/31/99)

Pollutant	Manufacturer's Design[a] (lb/hr)	Maximum Estimated Emissions lb/hr	TPY[b]
PM / PM10	0.65[c]	0.65	2.85
NO_x	3.0	3.0	13.1
SO_2	0.82[d]	0.82	3.60
CO	3.0	3.0	13.1
VOC	1.0	1.0	4.4

Footnotes:

[a] Estimated emissions obtained from design information provided by BSP Thermal Sytems, Inc.

[b] Based on 8,760 hours per year of operation.

[c] Based on uncontrolled emissions of 32.5 lb/hr and 98% control efficiency with wet scrubber system.

[d] Based on No. 2 fuel oil combustion only. Calculation based on manufacuter's data for the Granular Carbon Furnace is shown below.

Hourly SO_2 Emission Rate = 120 gal oil/hr * 0.05% * 6.83 lb sulfur/gal oil * 2 lb SO_2/ 1 lb sulfur
= 0.82 lb SO_2/hr

Annual SO_2 Emission Rate = 0.82 lb SO_2/hr * 8,760 hr/yr * 1 Ton/2000 lb
= 3.6 TPY SO_2

Scrubber control of SO_2 emissions was not considered.

Table 6-3. U.S. Sugar Clewiston Mill Maximum Fuel Oil Burning And SO_2 Emissions - Future Operation @ 2.5% S Fuel Oil (Revised 07/31/99)

Boiler	Total Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Fuel Oil gal/hr [a]	Fuel Oil MMBtu/hr	Bagasse MMBtu/hr	Bagasse lb/hr(dry)	SO_2 Emissions Fuel Oil (lb/hr)	SO_2 Emissions Bagasse [b] (lb/hr)	SO_2 Emissions Total (lb/hr)	SO_2 Emissions Total (g/s)
					MAXIMUM 3-HOUR CASE					
1	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
2	495.6 [c]	225.1	1,500	225.0	270.6	37,583	615.0	18.8	633.8	79.86
3	342.0 [c]	135.1	900	135.0	207.0	28,750	369.0	14.4	383.4	48.31
4	633.0	225.1	1,500	225.0	408.0	56,667	615.0	67.7 [d]	682.7	86.02
7	812.0	249.0	0	0.0	812.0	112,778	0.0	138.0 [d]	138.0	17.39
Totals	2,778.2		5,400 (16,200 gallons per 3-hour period)	810.0	1,968.2	273,361	2,214.0	257.7	2,471.7	311.4
					MAXIMUM 24-HOUR CASE					
1	495.6	225.1	1,070	160.5	335.1	46,542	438.7	23.3	462.0	58.21
2	495.6	225.1	1,070	160.5	335.1	46,542	438.7	23.3	462.0	58.21
3	342.0	135.1	600	90.0	252.0	35,000	246.0	17.5	263.5	33.20
4	600.0	225.1	960	144.0	456.0	63,333	393.6	75.7 [d]	469.3	59.13
7	738.0	249.0	0	0.0	738.0	102,500	0.0	125.5 [d]	125.5	15.81
Totals	2,671.2		3,700 (88,800 gallons per 24-hour period)	555.0	2,116.2	293,917	1,517.0	265.2	1,782.2	224.6

[a] Total fuel usage for all boilers based on current permit limits. Individual boiler rates selected to maximize SO_2 emissions.

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

[c] Permit limit for 24-hour average.

[d] Based on permit limit of 0.166 lb/MM Btu for Boiler No. 4, and 0.17 lb/MMBtu for Boiler No. 7.

[e] For modeling purposes, this SO_2 emission rate is slightly higher than that shown in Table 2-1 for Boiler No. 4. This is due to not accounting for the differneces in combustion efficiency between bagasse and fuel oil.

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

Table 2-1. Short Term Emissions of Regulated Pollutants for Boiler No. 4 (Revised 07/31/99)

Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor 1-Hour Max. (MMBtu/hr)(a)	Activity Factor 24-Hour Avg. (MMBtu/hr)(a)	Maximum Hourly Emissions (lb/hr)	Maximum 24-Hour Emissions (lb/hr)
			Carbonaceuos Fuel			
Particulate Matter (PM)	0.15	1	633	600	95.0	90.0
Particulate Matter (PM10)	0.14	2	633	600	88.3	83.7
Sulfur dioxide	0.166	3	633	600	105.1	99.6
Nitrogen oxides	0.25	4	633	600	158.3	150.0
Carbon monoxide	6.5	1	633	600	4,114.5	3,900.0
VOC	0.90	5	633	600	569.7	540.0
Sulfuric Acid Mist	0.010	6	633	600	6.4	6.1
Lead	4.45E-04	7	633	600	0.28	0.27
Mercury	3.8E-05	8	633	600	0.0241	0.0228
Beryllium	--	7	633	600	--	--
			No. 6 Fuel Oil			
Particulate Matter (PM)	0.10	1	225	--	22.5	22.5
Particulate Matter (PM10)	0.10	9	225	--	22.5	22.5
Sulfur dioxide	2.73	10	225	--	615.0	615.0
Nitrogen oxides	0.31	11	225	--	69.8	69.8
Carbon monoxide	0.033	11	225	--	7.5	7.5
VOC	0.0019	11	225	--	0.4	0.4
Sulfuric Acid Mist	0.044	6	225	--	9.9	9.9
Lead	1.01E-05	11	225	--	2.27E-03	2.27E-03
Mercury	7.53E-07	11	225	--	1.70E-04	1.70E-04
Beryllium	1.85E-07	11	225	--	4.17E-05	4.17E-05
			Maximum No. 6 Fuel Oil/ Remainder Bagasse			
Particulate Matter (PM)			530	499	68.3	63.6
Particulate Matter (PM10)			530	499	65.1	60.7
Sulfur dioxide			530	499	665.7	660.5
Nitrogen oxides			530	499	146.2	138.2
Carbon monoxide			530	499	1,993.3	1,787.2
VOC			530	499	275.4	246.8
Sulfuric Acid Mist			530	499	13.0	12.7
Lead			530	499	0.14	0.12
Mercury			530	499	0.012	0.011
Beryllium			530	499	4.17E-05	4.17E-05
			Maximum Any Combination			
Particulate Matter (PM)					95.0	90.0
Particulate Matter (PM10)					88.3	83.7
Sulfur dioxide					665.7	660.5
Nitrogen oxides					158.3	150.0
Carbon monoxide					4,114.5	3,900.0
VOC					569.7	540.0
Sulfuric Acid Mist					13.0	12.7
Lead					0.28	0.27
Mercury					0.0241	0.0228
Beryllium					4.17E-05	4.17E-05

Footnotes

(a) Maximum 1-hour activity factor is based on a steam production of 300,000 lb/hr at 600 psig, 750 F.
Maximum 6-hour average activity factor based on steam production rate of 285,000 lb/hr at 600 psig, 750 F.
Enthalpy of steam = 1,378 Btu/lb. Enthalpy of feedwater = 218 Btu/lb. Net enthalpy = 1,160 Btu/lb.
Boiler efficiency = 80% on fuel oil and 55% on bagasse.
Derivation of heat input for No. 6 Fuel oil/Bagasse combination firing:
Max 1-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (300,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 168 MMBtu/hr
Required heat input to boiler from bagasse = 168 MMBtu/hr / 55% eff. = 305.5 MMBtu/hr
Total heat input required = 225 + 305.5 = 530 MMBtu/hr
Max 24-hr case: Max oil = 225 MMBtu/hr x 80% eff. = 180 MMBtu/hr into steam.
Remainder needed into steam = (285,000 lb/hr steam x 1,160 Btu/lb) - 180 MMBtu/hr = 150.6 MMBtu/hr
Required heat input to boiler from bagasse = 150.6 MMBtu/hr / 55% eff. = 273.8 MMBtu/hr
Total heat input required = 225 + 274 = 499 MMBtu/hr

References

1. Current BACT permit limit for Clewiston.
2. Based on limited source testing of bagasse boiler which indicated 93% of PM was PM10.
3. Current BACT permit limit for Clewiston Boiler No. 4. Based on 0.2% sulfur content of bagasse (dry basis), 3,600 Btu/lb(wet) and 50% moisture; and 40% removal in wet scrubber.
4. Equivalent to current permit limit for Clewiston Boiler No. 4.
5. Proposed permit limit; based U.S. Sugar Bryant mill RACT limitation for carbonaceous fuel burning.
6. Based on assuming 5% of SO2 emissions are equal to SO3, based on AP-42 Section 1.3, Fuel Oil Combustion. Conversion of SO3 to H2SO4 (SO3 x 98/80).
7. Based on AP-42, Section 1.6, Wood Waste Combustion. Represents controlled emissions.
8. Based on stack testing of 5 bagasse boilers in Florida (refer to appendices).
9. Assumed as 100% of PM emissions.
10. Based on 2.5% S fuel oil; 150,000 Btu/gal; 8.2 lb/gal; assumes 100% conversion of sulfur to SO2.
11. Based on AP-42, Section 1.3, Fuel Oil Combustion.
NOx - 47 lb/1000 gal; CO - 5 lb/1000 gal; VOC - 0.28 lb/1000 gal;
Lead - 1.51E-03 lb/1000 gal; Mercury - 1.13E-04 lb/1000 gal; Beryllium - 2.85E-05 lb/1000 gal

Example Calculations

Single Fuel Combustion:
Hourly Emission Rate = Emission Factor X Activity Factor (1-hour maximum)

Multiple Fuel Combustion:
= {(Bagasse Activity Factor - Fuel Oil Activity Factor) x Bagasse Emission Factor}
+ (Fuel Oil Activity Factor x Fuel Oil Emission Factor)

Table A. Summary of SO_2 Emission Tests on Bagasse Boilers at U.S. Sugar Clewiston Mill

Unit	Date	Run	Heat Input Rate (MMBTU/hr)	Bagasse Heating Value (a) (BTU/lb)	Bagasse Burning Rate (TPH)	Sulfur Content (b) (%)	Theoretical SO_2 Emissions (lb/hr)	Measured SO2 Emissions		Inherent SO_2 Removal Efficiency (%)
								lb/hr	lb/MMBtu	
Boiler 1	2/8/94	1	415.8	3,900	53.3	0.05	106.6	4.4	0.011	95.9
		2	401.8	3,900	51.5	0.05	103.0	4.0	0.010	96.1
Boiler 2	2/8/94	1	419.8	3,900	53.8	0.05	107.6	5.0	0.012	95.4
Boiler 4	12/23/85	1	561.4	3,683	76.2	0.04	121.9	1.3	0.002	99.0
		2	562.7	3,683	76.4	0.04	122.2	0.8	0.001	99.3
		3	532.3	3,683	72.3	0.04	115.6	0.8	0.002	99.3
	2/1/94	1	592.2	3,900	75.9	0.05	151.8	4.1	0.007	97.3
		2	595.2	3,900	76.3	0.05	152.6	6.0	0.010	96.1
	2/7/94	1	587.5	3,900	75.3	0.05	150.6	5.3	0.009	96.5
		2	599.5	3,900	76.9	0.05	153.7	4.8	0.008	96.9
		3	582.1	3,900	74.6	0.05	149.3	8.1	0.014	94.5
		4	586.9	3,900	75.2	0.05	150.5	6.5	0.011	95.7
	2/17/94	1	608.7	3,900	78.0	0.05	156.1	4.9	0.008	96.9
		2	584.5	3,900	74.9	0.05	149.9	3.5	0.006	97.7
		3	623.7	3,900	80.0	0.05	159.9	3.7	0.006	97.7
		4	631.7	3,900	81.0	0.05	162.0	3.8	0.006	97.7
Boiler 5	12/6/95	1	242.5	3,900	31.1	0.05	62.2	0.1	0.000	99.8
		2	235.9	3,900	30.2	0.05	60.5	0.3	0.001	99.5
		3	234.3	3,900	30.0	0.05	60.1	0.1	0.001	99.8
Boiler 7	11/18/97	1	762.0	3,917	97.3	0.07	272.4	11.1	0.015	95.9
		2	735.0	3,917	93.8	0.07	262.7	3.1	0.004	98.8
		3	733.0	3,917	93.6	0.07	262.0	28.1	0.038	89.3
								Average =	0.008	97.0
								Maximum =	0.038	99.8

(a) Where actual bagasse analysis data not available, heating value of 3,900 Btu/lb was assumed.
(b) Where actual bagasse sulfur content data not available, 0.05 % S, wet basis, was assumed.

NONFOSSIL FUELED BOILERS

Emission Test Report
U.S. Sugar Company
Bryant, Florida

Project No.: 80-WFB-6

Prepared for

Environmental Protection Agency
Office of Air Quality Planning and Standards
Emission Measurement Branch
Research Triangle Park
North Carolina 27711

by

James A. Peters and Charles F. Duncan

Contract 68-02-2818, Work Assignment No. 25

May 1980

MONSANTO RESEARCH CORPORATION
DAYTON LABORATORY
1515 Nicholas Road
Dayton, Ohio 45407

SECTION 1

INTRODUCTION

The Bryant Mill of U.S. Sugar Corporation in Bryant, Florida was emission tested by Monsanto Research Corporation (MRC) for the U.S. Environmental Protection Agency (EPA) under Contract No. 68-02-2818, Work Assignment No. 25. The objective of the sampling program was to obtain emissions data from well-controlled sources within the nonfossil fuel boilers category that could possibly be used for the development of new source performance standards.

The field test work was monitored by Dan Bivins, Field Testing Section, Emission Measurement Branch, EPA. The sampling performed by MRC was directed by Charles F. Duncan as team leader. Gaseous and particulate emissions were determined at the outlet of the pollution control device serving Boiler #2. A composite sample of boiler feed was collected with each run so that a material balance could be attempted.

The sampling at the Bryant Mill was conducted by MRC during December 16-18, 1979. The collection methods employed were EPA Methods 1, 2, 3, 4, 5, 6, 7, and 9, with particulate sizing by Andersen cascade impactor.

Quality assurance/quality control in the sampling area covered such activities as instrument calibration, using standard or approved sampling methods, chain-of-custody procedures, and protocols for the recording and calculation of data. QA/QC in the analysis area involved using only validated analysis methods, periodic operator QC checking and training, sample QC by the use of splits, reference standards, and spikes, and interlaboratory audits.

SECTION 2

SUMMARY OF RESULTS

Pollutants which were measured for this emission test were particulate matter, particle size, CO_2, CO, SO_2, NO_x, and plume opacity. Table 1 presents the sampling and analysis schedule in condensed form.

TABLE 1. BRYANT PLANT SAMPLING AND ANALYSIS SCHEDULE

Sampling site	Total number of samples	Sample type	Sampling method	Minimum sampling time	Initial analysis Type	Initial analysis Method
Scrubber outlet	3	Particulate matter	EPA 5	60 min		
Scrubber outlet	3	Particle-size distribution	Andersen			
Scrubber outlet	3	Integrated gas analysis	EPA 3		CO_2, O_2, CO	EPA 3
Scrubber outlet	3	SO_2	EPA 6, option 2	Same as Method 5		
Scrubber outlet	3 runs, 4 samples each	NO_x	EPA 7	15 min intervals		
Scrubber outlet	3	Opacity	EPA 9			
Scrubber outlet	3 samples, 2 fuel analyses each	ASTM			Ultimate analysis and heating value	ASTM

The Bryant Mill operates three waste-fired boilers fed with bagasse. The center boiler, Boiler #2, was tested. Boiler #2 utilizes dual scrubbers in parallel for pollution abatement. The outlet stack is located directly above the scrubbers.

Three test runs were performed, each consisting of 96 minutes of sampling time. Forty-eight traverse points were used, six points in each of the eight sampling ports. The first run was completed December 17. During the run, the boiler operated normally, in the range of 145,000 to 160,000 lb/hr of steam, until more than halfway through the test, when the bagasse feed was interrupted. The steam loading dropped to about 60,000 lb/hr and oil began to be burned. The test was interrupted several minutes after the drop in steam loading and was begun again after the bagasse feed rate and the boiler operation returned to normal almost 2 hours later. During the last several minutes of the test before the interruption, about 75 gal of oil was burned. Bagasse alone was burned the remainder of the run.

The remaining two runs of the test were completed on December 18. Through both runs the boiler operated normally and bagasse alone was burned. The steam loading ranged from 125,000 to 165,000 lb/hr, with an average of 151,000 lb/hr, in Run 2 and from 130,000 to 170,000 lb/hr, with an average of 144,000 lb/hr, in the third run. Both runs were within the normal operating range. During the third run, soot blowing was performed.

Tables 2 and 3 contain the summarized particulate emission data and stack gas parameters. Moisture in the stack gas was unusually high -- 32 percent H_2O. Integrated gas analysis results for each run are given in Table 4.

Table 5 contains a summary of the particle sizing results; each Andersen cascade impactor run was made after completing a Method 5 run. The #1 impactor test was discarded because the filter media was soaked with water. Due to the boiler #2 plume merging with the other boilers' plumes, opacity readings were not able to be made.

Samples for SO_2 emissions were taken concurrently with particulate emission runs by using the back half of the Method 5 train. Due to the very low sulfur content of the bagasse feed, emissions of SO_2 were below the detection limit (3.4 mg SO_2/m^3) of Method 6, and no data are presented. = 3.54 lb/hr

Samples for NO_x emissions were collected just after each particulate emission test and are summarized in Table 6.

Composite fuel samples of bagasse were taken with each run from the conveyor feeding the boiler, and ultimate analysis and fuel values were determined. A fuel oil sample from run #1 was also collected and analyzed for fuel value. Table 7 presents the fuel analysis results.

A summary of boiler operating conditions during testing is given in Table 8. Average steam temperatures and pressures were determined by averaging 15-min readings in order to calculate steam enthalpy.

TABLE 2. PARTICULATE EMISSION DATA AND STACK GAS PARAMETERS, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979 (ENGLISH UNITS)

Run number	Date	Time, min	Stack temperature, °F	Flow, dscfm	H_2O, %	Isokinetic, %	Emissions: Actual gr/dscf	Emissions: Actual lb/hr	Emissions: Actual lb/mm Btu	Emissions: Corrected to 12% CO_2 gr/dscf
1	12/17/79	96	161	58,515	31.3	105.7	0.1298	65.1	0.3505	0.1442
2	12/18/79	96	164	58,720	33.1	105.6	0.1001	50.4	0.2547	0.1082
3	12/18/79	96	162	58,825	31.7	101.6	0.1135[a]	57.2	0.3034	0.1205[a]
Average		96	162	58,687	32.0		0.1145	57.6	0.3029	0.1243

[a]Run #3 included a soot blow.

TABLE 3. PARTICULATE EMISSION DATA AND STACK GAS PARAMETERS, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979 (METRIC UNITS)

Run number	Date	Time, min	Stack temperature, °C	Flow, dncmpm	H_2O, %	Isokinetic, %	Emissions: Actual g/dncm	Emissions: Actual kg/hr	Emissions: Actual kg/GJ	Emissions: Corrected to 12% CO_2 g/dncm
1	12/17/79	96	72	1,657	31.3	105.7	0.2971	29.5	0.1506	0.3301
2	12/18/79	96	73	1,663	33.1	105.6	0.2292	22.9	0.1097	0.2478
3	12/18/79	96	72	1,666	31.7	101.6	0.2599[a]	26.0	0.1107	0.2760[a]
Average		96	72	1,662	32.0		0.2621	26.1	0.1303	0.2846

[a]Run #3 included a soot blow.

TABLE 4. SUMMARY OF INTEGRATED GAS ANALYSES, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979

Run number	Date	CO_2, %	CO, %	O_2, %	N_2, %	Mw lb/lb mole
1	12/17/79	10.8	0.0	9.2	80.0	30.1
2	12/18/79	11.1	0.0	9.0	79.9	30.1
3	12/18/79	11.3	0.0	9.4	79.3	30.2
Average		11.1	0.0	9.2	79.7	30.1

TABLE 5. SUMMARY OF ANDERSEN PARTICLE SIZING RESULTS, U.S. SUGAR-BRYANT MILL, DECEMBER 17-18, 1979

Run No. 1

Discarded

Run No. 2

Flow rate = 0.927 acfm
Isokinetic rate = 107.1%

Stage	Size range	Percent in size range	Cumulative % <size range
Preimpactor	>10.50	3.99	94.55
0	>10.50	1.46	94.55
1	6.50 - 10.50	3.06	91.52
2	4.30 - 6.50	7.98	83.54
3	2.95 - 4.30	11.30	72.24
4	1.88 - 2.95	12.40	59.94
5	0.94 - 1.88	12.90	46.94
6	0.58 - 0.94	19.15	27.79
7	0.39 - 0.58	16.49	11.30
Filter	0.0 - 0.39	11.30	0

Run No. 3

Flow rate = 0.908 acfm
Isokinetic rate = 105.5%

Stage	Size range	Percent in size range	Cumulative % <size range
Preimpactor	>10.60	6.56	91.43
0	>10.60	2.01	91.43
1	6.60 - 10.60	4.28	87.14
2	4.40 - 6.60	7.47	79.67
3	3.00 - 4.40	8.66	71.01
4	1.90 - 3.00	8.66	62.35
5	0.96 - 1.90	10.48	51.87
6	0.59 - 0.96	20.60	31.27
7	0.40 - 0.59	16.68	14.59
Filter	0.0 - 0.40	14.59	0

Particle Sizing Summary

An eight stage Anderson Mark III impactor was used for particle sizing tests. Because of the presence of entrained water or highly saturated gases, it was decided to utilize an impactor preseperator to protect the impactor substrates and jet stages from the effects of water. This was thought superior to heating the impactor because heating may change the stage collection efficiencies.

A particle sizing test run was made immediately following each method 5 test run. The tests were conducted at the point of average velocity shown in the method 5 run. The impactor was used with a method 5 sampling train modified for its use by the use of a flexible line between the probe and impingers. The impactor was placed in the stack at the nozzle end of the probe. Isokinetic sampling was maintained throughout the tests.

The run 1 impactor test has been discarded because the filter media was soaked with water. Exactly how this happened was unknown. Runs 2 and 3 appear to be very satisfactory however. The preweighed filters following jets stages 0 through seven were collected and placed in petri dishes. The preweighed back up filter following plate eight (not a jet stage) was also placed in a petri dish. The acetone wash of the preseperator, inlet cone, and top surface of plate zero was placed in a clean sample bottle marked "preimpactor". Although the individual weights of the preimpactor wash and the first filter (from jet stage 0) have been recorded in Table 1, these have been added together for sizing using the 0 stage cut point. Cut sizes (dp_{50}) have been determined from the enclosed data furnished by Anderson Samplers, Inc.

Field data sheets have been enclosed. Orsat information was obtained from integrated bag and Burrell analyzer. Moisture values were taken from the accompanying EPA - 5 test run.

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Table 1. Anderson Mark III Sizing Summary

Run 2
Flow Rate = 0.927 ACFM
Isokinetic Rage = 107.1%

Stage	Size Range	Effective Cut Diameter	Final Weight mg	Initial Weight mg	Gain mg	% in Size Range	Cummulative % <Size Range
Preimpactor	>10.50	10.5	110.3755	110.3785	3.0	3.99	94.55
0	>10.50	10.5	131.8	130.7	1.1	1.46	94.55
1	6.50 - 10.50	6.5	122.5	120.3	2.3	3.06	91.52
2	4.30 - 6.50	4.3	137.4	131.4	6.0	7.98	83.54
3	2.95 - 4.30	2.95	128.8	120.3	8.5	11.30	72.24
4	1.88 - 2.95	1.88	140.4	131.1	9.3	12.40	59.84
5	0.94 - 1.88	0.94	130.7	121.0	9.7	12.90	46.94
6	0.58 - 0.94	0.58	145.2	130.8	14.4	19.15	27.79
7	0.39 - 0.58	0.39	132.4	120.0	12.4	16.49	11.30
Filter	0.0 - 0.39	-	252.0	243.5	8.5	11.30	0
					75.2		

26

Run 3
Flow Rate = 0.908 ACFM
Isokinetic Rate = 105.5%

Stage	Size Range	Effective Cut Diameter	Final Weight mg	Initial Weight mg	Gain mg	% in Size Range	Cummulative % <Size Range
Preimpactor	>10.60	10.6	103.8754	103.8682	7.2	6.56	91.43
0	>10.60	10.6	134.5	132.3	2.2	2.01	91.43
1	6.60 - 10.60	6.6	125.3	120.6	4.7	4.28	87.14
2	4.40 - 6.60	4.4	138.5	130.3	8.2	7.47	79.67
3	3.00 - 4.40	3.0	130.5	121.0	9.5	8.66	71.01
4	1.90 - 3.00	1.9	139.8	130.3	9.5	8.66	62.35
5	0.96 - 1.90	.96	131.9	120.4	11.5	10.48	51.87
6	0.59 - 0.96	.59	152.6	130.0	22.6	20.60	31.27
7	0.40 - 0.59	.40	138.7	120.4	18.3	16.68	14.59
Filter	0.0 - 0.40	-	260.2	244.2	16.0	14.59	0
					109.7		

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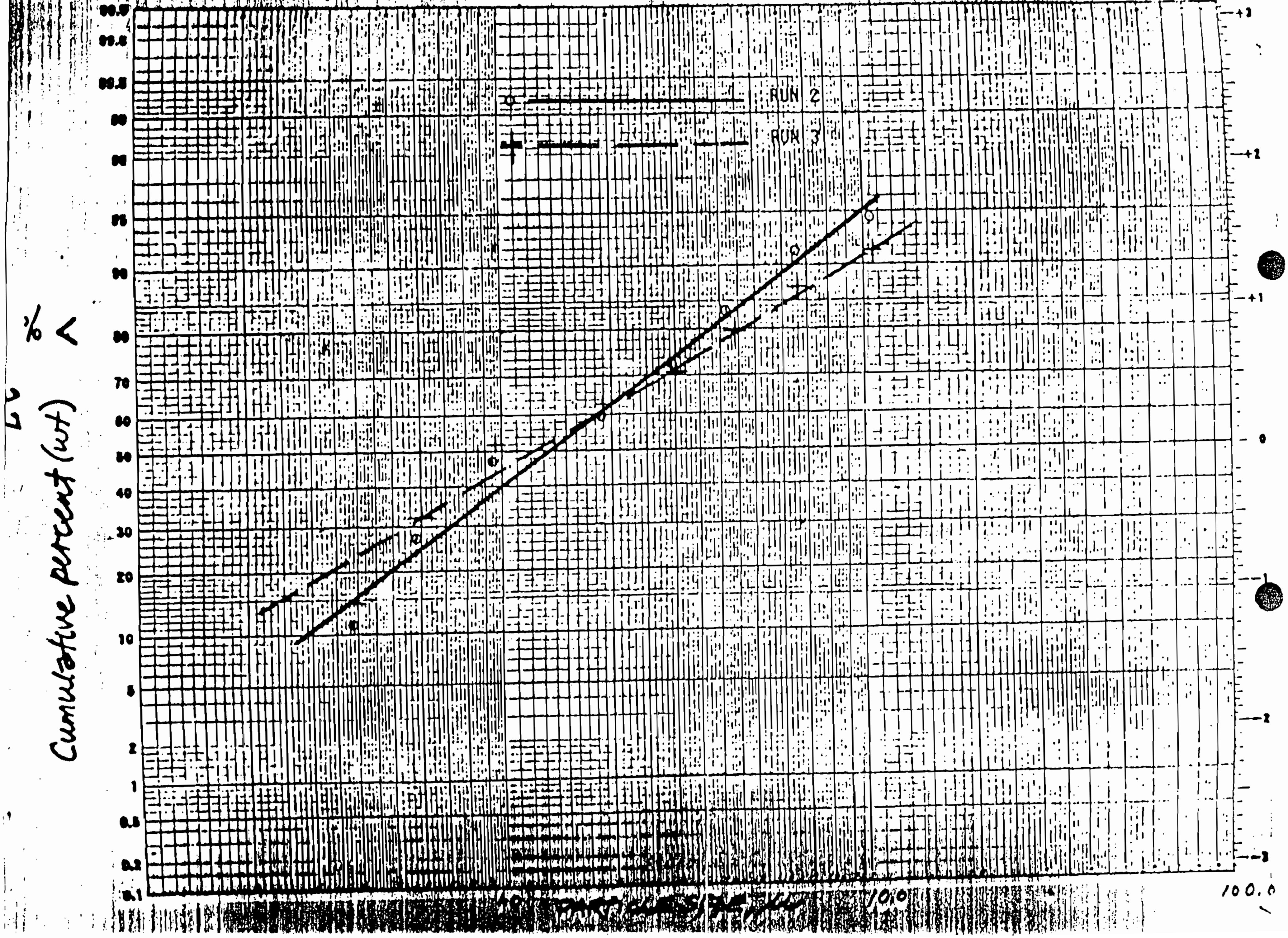
CUMULATIVE PARTICLE SIZE DISTRIBUTION
FOR ANDERSEN RUNS 1 AND 2



Golder Associates Inc.

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

Golder Associates

May 20, 1999

9937532A/1

Florida Department of Environmental Protection
2295 Victoria Avenue Suite 364
Fort Myers, Florida 33901

Attention: Phillip Barbaccia

RE: U.S. Sugar Corporation
Clewiston Sugar Mill Expansion
Permit No. 0510003-004-AC
Hendry County - AP

Dear Mr. Barbaccia:

On behalf of United States Sugar Corporation (US Sugar), Golder Associates Inc. (Golder) is submitting to the Florida Department of Environmental Protection (FDEP) final as-constructed design information for the above referenced non-PSD air construction permit for the Clewiston sugar mill expansion. Since the construction permit was issued, U.S. Sugar's final as-constructed design engineering of the expansion has resulted in certain changes to the plant, which in turn has resulted in emissions changes.

The attached revised Table 3-1 shows the final design engineering specifications for the baghouses and the granular carbon regeneration furnace (GCRF) associated with the sugar mill expansion. During construction, in order to simplify the design and save construction costs, several emission source exhausts were combined and routed to a single exhaust. This reduced the number of installed baghouses from fifteen to eleven. To accommodate this change, the baghouse design capacities were modified along with the need to potentially operate the baghouses for a longer period of time. Even though the revisions increase potential individual point source emission rates over those approved under permit no. 0510003-004-AC, the number of emission sources has decreased which effectively counterbalances the increase in emission rates.

Along with the change in operational hours of the baghouses, the GCRF will also be permitted to operate for a longer period of time. Estimated emission increases associated with the change in hours of operation for the GCRF are shown in Table 3-2. The total particulate matter emissions from the GCRF and the eleven baghouses is approximately 14.92 tons per year (TPY). This is still below the PSD significant emission rate of 15 TPY for PM. Besides an increase in particulate matter emissions, emissions of other pollutants from the GCRF such as sulfur dioxide will potentially increase. However the increases are minimal and are still well below the PSD significant emission rates.

The revisions to the existing sources required that exhaust stacks be either relocated, removed, or renamed. The revised stack locations and their numbering conventions are shown on the plot plan Attachment UC-FE2B. Table 3-1 indicates the new numbering conventions in relation to the original stack numbers.

The attached revised Table 3-1 provided should replace Table 3-1 referenced in construction permit no. 0510003-004-AC. The attached Table 3-2 and plot plan (Attachment UC-FE2B) provided should replace their counterpart pages in the original permit application file. Enclosed is the permit modification application fee of $250.

US Sugar appreciates the Departments consideration of these revisions. If you have any questions or need further information concerning the revisions, please do not hesitate to contact me at (352) 336-5600, fax (352) 336-6603 or Don Griffin of US Sugar at (941) 902-2711, fax (941) 902-2729.

Sincerely,

David A. Buff

David A. Buff
Professional Engineer
PE SEAL No. 19011

DB/arz

cc: Don Griffin, US Sugar
Lisa Gefen, US Sugar
Murray Brinson, US Sugar
Paul Wesson, Golder Associates

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

Source / Vent Name	Original Stack Number	New Stack Number	Control Type	Manufacturer/Model	Design Capacity	Control Efficiency (percent)	Operating Hours	PM/PM10 Emissions (gr/dscf)	(lb/hr)	(g/s)	(TPY)
Screening & Distribution Vacuum	None	S-1	Baghouse	Hoffman	990 dscfm	99.9	7,680	0.00754 ^a	0.064 ^b	0.00806	0.246
100 lb Bagging Vacuum System	None	S-2	Baghouse	Hoffman	872 dscfm	99.9	7,680	0.00856 ^a	0.064 ^b	0.00806	0.246
5 lb Bagging Vacuum System	None	S-3	Baghouse	Hoffman	984 dscfm	99.9	7,680	0.00759 ^a	0.064 ^b	0.00806	0.246
Packaging Dust Collector	S-16	S-4	Baghouse	Hosokawa Mikropul	9,589 dscfm	99.9	7,680	0.0025	0.205	0.0259	0.789
Screening and Distribution #1	S-14	S-5	Baghouse	Hosokawa Mikropul	2,668 dscfm	99.9	8,760	0.0025	0.057	0.00720	0.250
Screening and Distribution #2	None	S-6	Baghouse	Hosokawa Mikropul	8,755 dscfm	99.9	8,760	0.0025	0.188	0.0236	0.822
Conditioning Silo No. 2	S-9	S-7	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.00713	0.248
Conditioning Silo No. 4	S-10	S-8	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.00713	0.248
Conditioning Silo No. 6	S-11	S-9	Baghouse	Hosokawa Mikropul	2,641 dscfm	99.9	8,760	0.0025	0.057	0.00713	0.248
White Sugar Dryer	S-8	S-10	Baghouse	BACT Engineering	94,488 dscfm	99.9	7,680	0.00177 ^a	1.436 ^b	0.181	5.51
V.H.P. Sugar Dryer	S-18	S-11	Baghouse	BACT Engineering	110,042 dscfm	99.9	3,960	0.00172 ^a	1.625 ^b	0.205	3.22
Granular Carbon Furnace	S-19	S-12	None	--	--	--	8,760	--	0.650	0.0819	2.85
								Total =	4.52	0.5699	14.92

Footnotes:

^a. Back calculated from guaranteed emission rate and design flow rate.

^b. Manufacturer's guaranteed emission rate.

Note: dscfm = dry standard cubic foot per minute.
gr/dscf = grains per dry standard cubic foot
lb/hr = pounds per hour
TPY = tons per year

Table 3-2. Emissions From Granular Carbon Regeneration Furnace, USSC Clewiston Mill Expansion

Pollutant	Manufacturer's Design(a) (lb/hr)	Maximum Estimated Emissions	
		lb/hr	TPY (b)
PM / PM10	0.65 (c)	0.65	2.85
NOx	3.0	3.0	13.1
SO2	0.49 (d)	0.49	2.15
CO	3.0	3.0	13.1
VOC	1.0	1.0	4.4

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

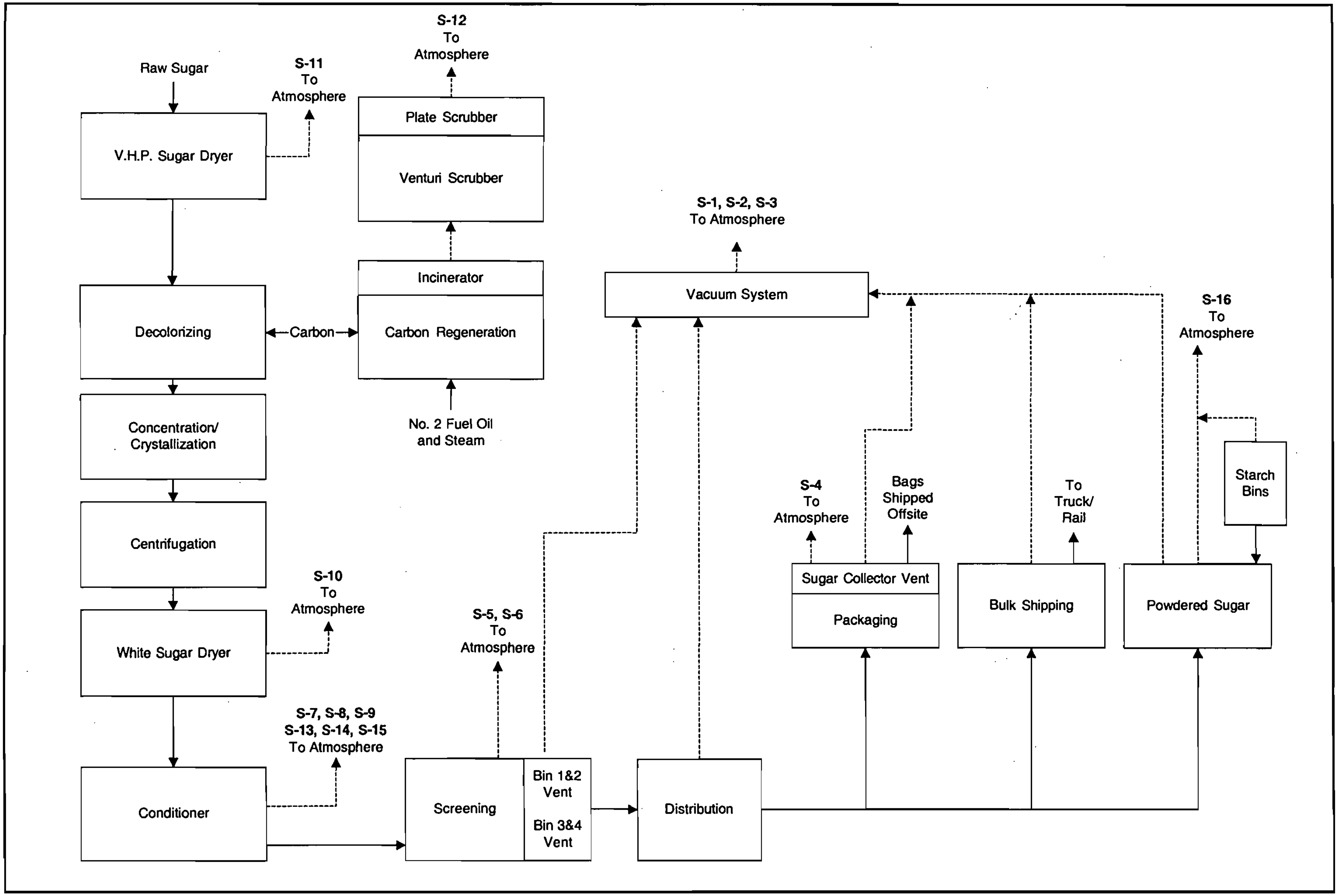
(b) Based on 8,760 hours per year of operation.

(c) Based on uncontrolled emissions of 32.5 lb/hr and 98% control efficiency with wet scrubber system.

(d) Based on No. 2 fuel oil combustion only. Calculation based on Granular Carbon Furnace manufacturer's data is shown below. Scrubber SO2 removal is not considered.

120 gal oil/hr * 0.03% * 6.83 lb sulfur/gal oil * 2 lb SO2/ 1 lb sulfur = 0.49176 lb SO2/hr

0.49176 lb SO2/hr * 8,760 hr/yr * 1 Ton/2000 lb = 2.15 TPY SO2



Attachment UC-EU2-L1
Mill Expansion
Process Flow Diagram
U.S. Sugar Corporation
Clewiston, FL

Process Flow Legend
Solid/Liquid ⟶
Air - - - ->

Mill Expansion Flow Diagram

Filename: 9937515Y/F2/WP/UCEU2L1.VSD

Date: 08/03/99

Golder Associates

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Golder Associates

October 20, 1999 9937515

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

Attention: Jeffery Koerner, P.E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – PSD PERMIT APPLICATION FOR BOILER NO. 4 AND THE SUGAR REFINERY AT THE CLEWISTON MILL
INFORMATION SUBMITTAL NO. 5

Dear Mr. Koerner:

Based on my conversations last week with Cleve Holladay, and Stan Krivo at EPA Region 4, regarding U.S. Sugar's PSD permit application to modify operation of Boiler No. 4 and expand the sugar refinery operation, a few additional questions have been raised in regards to approval of the ISC-PRIME model for the Clewiston mill. The purpose of this letter is to respond to these questions. The questions and our response are provided below.

1. Attached is a diagram showing the location of the Boiler No. 4 stack and other stacks at U.S. Sugar in relation to buildings. A scale is provided on the diagram. Please use this diagram in conjunction with Attachment UC-FE-2 included in the permit application form, and with building information presented in Section 6.0 of the PSD report (page 6-13 and Table 6-13).

2. Regarding baseline emissions used for Boiler No. 4 in the significant impact analysis, the following information is provided. Attached is Table A (filename: Blr4sig.xls) which summarizes the baseline emissions used in the significant impact analysis. All baseline emissions are based on the actual emission factors for Boiler No. 4 obtained from source testing (refer Appendix B, Table B-1). The emission factors used in this table are the same as those used to calculate the current actual annual emissions for PSD source applicability (see table 3-3 of PSD report). For all but NO_x, the boiler heat input rate used to calculate the baseline emissions were based on actual historical boiler operation, and was 546 MMBtu/hr for the 24-hour averaging time (for PM/PM_{10}), and 600 MMBtu/hr for the 1-hour averaging time. For SO_2, it was conservatively assumed that no fuel oil burning was occurring, and that the SO_2 was solely due to bagasse firing. In the case of NO_x, the baseline emissions were conservatively based on the actual annual baseline NO_x emissions (70.6 TPY from Table 3-3) and then dividing by 8,760 hr/yr. This would

render the baseline NO_x emissions lower as actual operation has been only 160 days/yr (3,840 hr/yr) or less.

3. The CO and PM_{10} emissions used in the AAQS/PSD modeling for other boilers at U.S. Sugar Clewiston were shown in Table 6-4 of the PSD report. These emissions should match the model input files. For PM_{10} emissions, the emissions are based on the permit limits for PM for each boiler. For CO, the emission factors are based on actual CO test data available for each boiler (a revised Table 6-4 was forwarded to Jeff Koerner at FDEP on Sep. 22, 1999).

4. All other questions should be addressed by Steve Mark's e-mail to Cleve Holladay and Stan Krivo dated Oct. 14, 1999. Steve has place all model input/output data onto the Golder FTP site.

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

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

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

DB/jkk

Enclosures

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

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cc: SFD
EPA
NPS
File
C. Holladay, BAR

Table A. Baseline Emissions Used in the Significant Impact Analysis for Clewiston Boiler No. 4

Pollutant	Emission Factor (a)	Heat Input (b) (MMBtu/hr)	Emissions (lb/hr)	(g/s)
Particulate Matter (PM)	0.12 lb/MMBtu	546	65.5	8.26
PM_{10}	0.112 lb/MMBtu	546	61.2	7.71
Sulfur Dioxide	0.008 lb/MMBtu	600	4.8	0.60
Nitrogen Oxides	0.082 lb/MMBtu	(c)	16.2	2.04
Carbon Monoxide	6.36 lb/MMBtu	600	3816.0	480.82

(a) Based on source test data from Boiler No. 4.
(b) Based on maximum steam rates actually reached in operation for Boiler No. 4.
(c) Based on baseline NOx emissions of 70.9 TPY, assuming 8,760 hr/yr operation.

US Sugar Corp - Clewiston Mill

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Review Comments on Final Air Quality Impact Analysis
US Sugar Corporation Clewiston Mill
Clewiston, Florida

Dear Mr. Linero:

Thank you for providing a review copy of the December 17, 1999, Golder Associates' letter containing the final plant configuration, fuel consumption information, air emissions data, and air quality impact assessment associated with the U.S. Sugar Corporation - Clewiston Mill. This facility was issued Final Permit No. 0510003-009-AC (PSD-FL-272) in November 1999. The purpose of Golder Associates' letter was to fulfill permit condition 7(c) which requires submittal of a final compliance demonstration for this modified facility. The following presents our air quality related comments on this letter. [Note: These comments were provided to FL DEP representative on February 2, 2000.]

1. PSD Expanding Sources - Previous communications with Golder Associates indicated current U.S. Sugar PSD expanding sources have no monthly or annual permit operational limits. They have therefore been modeled as operating for the full year. The emission rates used should be based on actual operations not permit allowables. In addition, an explanation is needed as to why Boiler 1 and 2 expansion emission rates (negative modeled emissions) are always equal to the increment consumption emission rates. This is not a normal modeling technique for PSD expanders.

2. Location of U.S. Sugar Sources - Table 10 of the December 1999, letter has new locations for the U.S. Sugar sources. These new locations were not included in the modeling provided in support of this letter.

3. CO Emission Rates - Table 7 of the letter presents CO emission rates for each of the two averaging periods of concern. Only the 1-hour rates were used in the modeling. Because the 1-hour emission rates are larger than the 8-hour values, this procedure provides appropriately conservative concentrations.

4. Stack Exit Parameters - Although the stacks for Boilers 1-3 have been raised from 165 to 182 feet, the exit temperature, velocity, and stack diameter have not changed. To ensure correct values were used in the modeling, the provided stack exit parameters need to be confirmed.

5. SO_2 Impact Analysis - The SO_2 3-hour, 24-hour and annual PSD increment analyses were not performed to 100-m receptor grid resolution. Although not correctly modeled, the basic results should not change because the resultant concentrations were all less than 15 percent of the applicable PSD increment.

   The NAAQS analysis was performed correctly. The results show the 24-hour SO_2 NAAQS concentration to be 99 percent of the standard. Because of this and the above comments on some of the model input parameters, the NAAQS SO_2 impact assessment needs to be confirmed.

Thank you again for the opportunity to comment on this final air quality impact assessment for the U.S. Sugar - Clewiston Mill. If you have any questions regarding these comments, please direct them to Stan Krivo at 404-562-9123.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Koerner
C. Holladay
S. District
NPS