Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL USA 32653
Telephone (352) 336-5600
Fax (352) 336-6603
www.golder.com

Golder Associates

September 22, 2005

0537540/0537541

RECEIVED
SEP 26 2005
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Attention: Mr. Jeff Koerner, P.E., Air Permitting South

RE: UNITED STATES SUGAR CORPORATION
CLEWISTON AND BRYANT MILLS
TITLE V RENEWAL APPLICATION
COMPLIANCE ASSURANCE MONITORING (CAM) PLAN

Dear Mr. Koerner:

Please find enclosed four (4) copies of the Compliance Assurance Monitoring (CAM) plan to support United States Sugar Corporation's Title V operating permit renewal application. Please insert this document at the end of the Title V application recently submitted to your office. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

CB/DB/nav

cc: Don Griffin
Peter Briggs
Jose Garcia, Palm Beach County Health Unit
Ron Blackburn, FDEP Fort Meyers

L092205

Original Signatures

COMPLIANCE ASSURANCE MONITORING PLAN
(CAM PLAN)
UNITED STATES SUGAR CORPORATION
CLEWISTON AND BRYANT MILLS

Prepared For:
United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, FL 33440

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

September 2005

0537540/41

DISTRIBUTION:
4 Copies – FDEP
2 Copies – United States Sugar Corporation
1 Copy – Golder Associates Inc.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

1.0 CAM APPLICABILITY ANALYSIS

1.1 CAM RULE APPLICABILITY DEFINITION

On October 18, 2004, and September 12, 2001, the Florida Department of Environmental Protection (FDEP) issued Title V Air Operation Permit Nos. 0510003-017-AV and 0990061-006-AV to United States Sugar Corporation (U.S. Sugar) for the operation of the Clewiston and Bryant Mills, respectively. The Clewiston Mill permit expires on November 29, 2005, and the Bryant Mill permit expires on December 15, 2005. In order to renew the permits, a renewal application incorporating both the Clewiston and Bryant mills was submitted to the FDEP on June 1, 2005.

As part of the Title V renewal application, a Compliance Assurance Monitoring (CAM) Plan must be submitted as required by regulations adopted in Title 40, Part 64 of the Code of Federal Regulations (40 CFR 64). This regulation has been incorporated by reference in Rule 62-204.800, Florida Administrative Code (F.A.C.), and implemented in Rule 62-213.440, F.A.C.

CAM plans are required for all Title V permitted emissions units using control devices to meet federally enforceable emission limits or standards and that have pre-control emissions greater than "major" source thresholds. The term "major" is defined in the Title V regulations (40 CFR 70), but applied on a source-by-source basis. For most non-hazardous pollutants, the major source threshold is 100 tons per year (TPY). For hazardous air pollutants (HAPs), the threshold is 10 TPY for an individual HAP and 25 TPY for total HAPs combined.

The CAM rules contain specific exemptions for the applicability of CAM. Specifically exempted from CAM are emission limitations or standards promulgated under the following: Stratospheric Ozone Regulations contained in 40 CFR 82; the Acid Rain Program contained in 40 CFR 72; or those that are part of an emissions cap included in the Title V Permit. Also exempt are emission limitations or standards proposed after November 15, 1990, under the following: New Source Performance Standards (NSPS) contained in 40 CFR 60; and National Emission Standards for Hazardous Air Pollutants (NESHAPs) promulgated in 40 CFR 63. These limitations and standards have monitoring requirements equivalent to CAM included as part of the standard.

Inherent process equipment (IPE), or equipment that may have the effect of controlling emissions but is installed for the primary purpose of product recovery or raw material recovery, is also exempt from

CAM (40 CFR 64.1). In addition, CAM does not apply to any emission limit or standard for which the Title V permit specifies a continuous compliance determination method [40 CFR 64.2(b)(1)(vi)], provided that the method does not include an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device.

1.2 APPLICABILITY OF CAM TO EMISSIONS UNITS

A review of emission units at the U.S. Sugar Clewiston and Bryant Mills was conducted to determine the applicability of the CAM rule. This evaluation was conducted for each emissions unit and regulated pollutant. First, the existence of a "control device" as defined by the CAM rule was determined on a source-by-source basis for each pollutant. Those emissions units without control devices were eliminated from further consideration. The remaining emissions units were then evaluated on a pollutant-by-pollutant basis to determine if a control device was used to meet a federally enforceable emission limit or standard.

Each pollutant without a federally enforceable emission limit or standard, emitted from a given emissions unit, was eliminated from further consideration. Uncontrolled annual emissions were then determined for each remaining source-pollutant combination. If uncontrolled emissions for a pollutant emitted from a given emissions unit were below major source thresholds, as defined by the CAM rule, that pollutant was not further considered. Specific exemptions to the applicability of the CAM rule were also considered in this evaluation.

A summary of the results of this evaluation process is presented in Table 1-1. Each pollutant-specific emissions unit at the U.S. Sugar mills, and its applicability to CAM, is described in the following sections.

1.2.1 CLEWISTON BOILER NO. 1 (EU 001)

Boiler No. 1 is a vibrating-grate boiler that is fired by carbonaceous fuel (bagasse) and No. 2 fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 1 has a maximum capacity of 245,000 pounds per hour (lb/hr) steam and a maximum heat input rate of 495 million British thermal units per hour (MMBtu/hr) while burning carbonaceous fuel alone or in mixture with No. 2 fuel oil. The design maximum heat input due to No. 2 fuel oil alone is 208 MMBtu/hr, corresponding to a maximum of 1,541 gallons per hour (gph) of distillate oil. Fuel oil can include facility-generated "on-spec" used oil. No more than 3,500,000 gallons of distillate oil can be fired during any consecutive 12-month period. This boiler may also burn petroleum contaminated soils up to 2 percent by weight of the bagasse feed rate and a maximum of 500 cubic yards per season.

Boiler No. 1 has federally enforceable emission limits for particulate matter (PM) and sulfur dioxide (SO_2). Boiler No. 1 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 1. Since there is no control device controlling SO_2 emissions from Boiler No. 1, a CAM plan for SO_2 is not required.

1.2.2 CLEWISTON BOILER NO. 2 (EU 002)

Boiler No. 2 is a vibrating grate boiler that is fired by carbonaceous fuel (bagasse) and No. 2 fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 2 has a maximum capacity of 215,000 lb/hr steam and a maximum heat input rate of 447 MMBtu/hr while burning carbonaceous fuel alone or in mixture with No. 2 fuel oil. The design maximum heat input due to No. 2 fuel oil alone is 208 MMBtu/hr, corresponding to a maximum of 1,541 gph of distillate oil. Fuel oil can include facility-generated "on-spec" used oil. No more than 3,500,000 gallons of distillate oil can be fired during any consecutive 12-month period. This boiler may burn petroleum-contaminated soils up to 2 percent by weight of the bagasse feed rate and maximum 500 cubic yards per season.

Boiler No. 2 has federally enforceable emission limits for PM and SO_2. Boiler No. 2 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 2. Since there is no control device controlling SO_2 emissions from Boiler No. 2, a CAM plan for SO_2 is not required.

1.2.3 CLEWISTON BOILER NO. 4 (EU 009)

Boiler No. 4 is a traveling-grate boiler manufactured by Foster Wheeler that is fired by carbonaceous fuel and No. 2 fuel oil with a maximum sulfur content of 0.40 percent by weight. Boiler No. 4 has a maximum capacity of 300,000 lb/hr steam (1-hour maximum) and 285,000 lb/hr steam (24-hour average). The maximum heat input when firing bagasse alone is 633 MMBtu/hr (1-hour maximum) and 600 MMBtu/hr (24-hour average). The unit has two multi-stage combustion low-nitrogen oxide (NO_x) fuel oil burners. The maximum heat input due to No. 2 fuel oil firing is 326 MMBtu/hr, corresponding to 2,417 gph of distillate oil. No more than 500,000 gallons of distillate oil can be fired during any consecutive 12-month period.

Boiler No. 4 has federally enforceable emission limits for PM, SO_2, NO_x, carbon monoxide (CO), and volatile organic compounds (VOCs). Boiler No. 4 utilizes a Joy Turbulaire Impingement Scrubber, Size 200, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 4. Since there is no control device controlling NO_x, SO_2, CO, or VOC emissions from Boiler No. 4, CAM plans for NO_x, SO_2, CO, and VOC are not required.

1.2.4 CLEWISTON BOILER NO. 7 (EU 014)

Boiler No. 7 is a spreader-stoker vibrating-grate boiler that is fired by carbonaceous fuel (bagasse) and distillate fuel oil (Grade Nos. 1 and 2). Boiler No. 7 has a maximum capacity of 385,000 lb/hr steam (1-hour maximum) and 350,000 lb/hr steam (24-hour average). The maximum heat input rate is 812 MMBtu/hr (1-hour maximum) and 738 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to fuel oil alone is 326 MMBtu/hr (1-hour average), corresponding to 2,417 gph of distillate oil. No more than 4,500,000 gallons of distillate oil can be fired during any consecutive 12-month period.

Boiler No. 7 has federally enforceable emission limits for PM, particulate matter less than 10 microns in diameter (PM_{10}), NO_x, SO_2, CO, VOC, and sulfuric acid mist (SAM). Boiler No. 7 utilizes an electrostatic precipitator (ESP) to reduce PM/PM_{10} emissions. The wet sand separator (cyclone) removes sand and partially combusted bagasse fibers to protect the induced draft fan and ESP and is not considered a control device. The ESP is the control device for PM emissions from Boiler No. 7. As shown in Table 1-1, uncontrolled PM/PM_{10} emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM/PM_{10}, a control device is used to comply with the PM/PM_{10} emission limit; and because uncontrolled PM/PM_{10} emissions are greater than 100 TPY, a CAM plan is required for PM/PM_{10} for Boiler No. 7. Since there is no control device

Boiler No. 7. Since there is no control device controlling NO_x, SO_2, CO, VOC, or SAM emissions from Boiler No. 7, CAM plans for these pollutants are not required.

1.2.5 CLEWISTON BOILER NO. 8 (EU 028)

Boiler No. 8 is a membrane wall, balanced-draft stoker boiler fired with carbonaceous fuel and No. 2 distillate fuel oil with a maximum sulfur content of 0.05 percent by weight. Boiler No. 8 has a maximum heat input rate of 1,030 MMBtu/hr based on a 1-hour maximum steam rate of 550,000 lb/hr for carbonaceous fuel firing. The maximum permitted 24-hour average heat input rate for firing carbonaceous fuel is 936 MMBtu/hr corresponding to 500,000 lb/hr steam. The maximum permitted heat input rate for firing No. 2 fuel oil is 562 MMBtu/hr. Fuel oil can include facility-generated on-specification used oil.

Boiler No. 8 has federally enforceable emission limits for PM/PM_{10}, NO_x, SO_2, CO, VOC, hydrochloric acid (HCl), mercury (Hg), and ammonia (NH_3). Boiler No. 8 utilizes two wet cyclone collectors followed by an ESP to control PM/PM_{10} emissions. The wet cyclones remove sand and partially combusted bagasse fibers to protect the induced draft fan and ESP.

Boiler No. 8 is subject to the federal NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. This NESHAP was promulgated on September 13, 2004, and applies to new boilers that have commenced construction after January 13, 2003. The Subpart DDDDD rules regulate PM emissions from new boilers. As a result, Boiler No. 8 is subject to a post-November 15, 1990, NESHAP for PM; and therefore, this emissions unit is not subject to CAM for PM.

NO_x emissions are controlled by a selective non-catalytic reduction (SNCR) system. As shown in Table 1-1, uncontrolled NO_x emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for NO_x, a control device is used to comply with the NO_x emission limit; and because uncontrolled NO_x emissions are greater than 100 TPY, a CAM plan is required for NO_x for Boiler No. 8.

There are no control devices on Boiler No. 8 for SO_2, CO, VOC, or NH_3. Therefore, CAM plans for these pollutants are not required.

There are no control devices for Hg and HCl emissions on Boiler No. 8. U.S. Sugar will demonstrate compliance with the Hg limit specified in 40 CFR 63, Subpart DDDDD, by performing fuel sampling and analysis. Sections 63.7545(e) and 63.9(h)(2)(ii) require the owner or operator of a new boiler to submit a Notification of Initial Compliance Status. According to the Hg fuel analysis results in the initial compliance report for U.S. Sugar, Hg emissions are below detection limit, which is well below the maximum achievable control technology (MACT) limit. The initial compliance report also shows that HCl "controlled" emissions measured at the stack are approximately three times lower than the MACT limit. In addition, HCl emissions measured at the inlet to the wet cyclones serving Boiler No. 8 are approximately 20 percent of the MACT limit. Therefore, Boiler No. 8 can achieve the MACT standard for HCl and Hg without a control device. Since there are no control devices controlling HCl and Hg emissions from Boiler No. 8, CAM plans for these pollutants are not required.

1.2.6 CLEWISTON SUGAR PROCESSING OPERATIONS

The Sugar Processing Operations at the U.S. Sugar mill consist of multiple emissions units: VHP Sugar Dryer [Emission Unit (EU) 015], White Sugar Dryers Nos. 1 and 2 (EU 016 and EU 029); Granular Carbon Regeneration Furnace (GCRF) (EU 017); three Vacuum Systems (EU 018); three Conditioning Silos (EU 019); two Screening and Distribution Baghouses (EU 020); Alcohol Usage (EU 021); and a Packaging Baghouse (EU 022).

EU 021 (Alcohol Usage) has no control device, and therefore, is exempt from the CAM requirements.

Uncontrolled PM emission rates from the sugar refinery emission units are presented in Table 1-2. EUs 015 (VHP Sugar Dryer) and 016 (White Sugar Dryer No. 1) each have a baghouse, and EU 029 (White Sugar Dryer No. 2) has four cyclones followed by a wet scrubber. The uncontrolled PM emission estimates, based on dryer outlet grain loading and exhaust gas flow for the VHP Sugar Dryer and White Sugar Dryer No. 1 are approximately 50,000 TPY (shown in Table 1-2). This high emission rate shows that sugar dust recovery by an add-on control device would be necessary even without any air pollution control regulations. Therefore, the baghouses on the VHP Sugar Dryer and White Sugar Dryer No. 1 and the cyclones on the White Sugar Dryer No. 2 serve as IPE.

The White Sugar Dryer No. 2 (EU 029) wet scrubber has uncontrolled PM emissions, after the cyclones, of greater than 100 TPY; therefore, CAM is required for the wet scrubber.

EUs 017, 018, 019, 020, and 022 at the refinery each have a control device and a federally enforceable emission limit for PM. The emissions from EUs 018, 019, 020, and 022 are controlled with baghouses. There are a total of nine baghouses within these emissions units.

PM emissions from EU 017 (GCRF) are controlled with a wet venturi/impingement plate scrubber system, and VOC emissions are controlled with a direct-flame afterburner. Uncontrolled emissions of PM and VOCs from the GCRF are both less than 100 TPY; therefore, CAM is not required (see Tables 1-2 and 1-3). There is also no control device for SO_2 emissions from the GCRF; therefore, CAM is not required for SO_2.

Uncontrolled emissions of PM from the Vacuum System (EU 018) are more than 100 TPY with an estimated grain loading of 5 grains per dry standard cubic foot (gr/dscf) reaching each baghouse; therefore, CAM for PM is required for this unit (see Table 1-2).

PM emissions from the three Conditioning Silos (EU 019), Screening and Distribution System (EU 020), and Sugar Packaging System (EU 022) are controlled with baghouses. The baghouses control PM emissions from conveyor drop points, transfer points, bucket elevators, and other drop-type operations. Uncontrolled emissions of PM from each are less than 100 TPY; therefore, CAM is not required (see Table 1-2).

CAM applicability for the sugar refinery emission units is summarized in Table 1-1.

1.2.7 BRYANT BOILER NO. 1 (EU 001)

Boiler No. 1 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both new/virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 1 may also burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 1 has a maximum capacity of 194,600 lb/hr (24-hour average) steam, and a maximum heat input rate of 385 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to No. 6 fuel oil alone is 189 MMBtu/hr (1,295 gph), and the maximum allowable quantity of fuel oil fired on each calendar day is limited to 80,000 gallons combined, for Bryant Boilers 1, 2, and 3. The maximum expected operation hours of 6,168 hours per year are based on October 1 to June 14 operation.

Boiler No. 1 has federally enforceable emission limits for PM, SO_2, NO_x, and VOC. Boiler No. 1 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit, and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 1. Since there is no control device controlling NO_x, SO_2, or VOC emissions from Boiler No. 1, CAM plans for these pollutants are not required.

1.2.8 BRYANT BOILER NO. 2 (EU 002)

Boiler No. 2 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both new/virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 2 may also burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 2 has a maximum capacity of 194,600 lb/hr (24-hour average) steam and a maximum heat input rate of 385 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to No. 6 fuel oil alone is 189 MMBtu/hr (1,295 gph), and the maximum allowable quantity of fuel oil fired on each calendar day is limited to 80,000 gallons combined for Bryant Boilers 1, 2, and 3. The maximum expected operation hours of 6,168 hours per year are based on October 1 to June 14 operation.

Boiler No. 2 has federally enforceable emission limits for PM, SO_2, NO_x, and VOC. Boiler No. 2 utilizes two Joy Turbulaire Impingement Scrubbers, Size 40, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 2. Since there is no control device controlling NO_x, SO_2, or VOC emissions from Boiler No. 2, CAM plans for these pollutants are not required.

1.2.9 BRYANT BOILER NO. 3 (EU 003)

Boiler No. 3 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both new/virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 3 may also burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 3 has a maximum capacity of 194,600 lb/hr (24-hour average) steam, and a maximum heat input rate of 385 MMBtu/hr (24-hour average) while burning carbonaceous fuel alone or in mixture with fuel oil. The design maximum heat input due to No. 6 fuel oil alone is 189 MMBtu/hr (1,295 gph), and the maximum allowable quantity of fuel oil fired on each calendar day is limited to 80,000 gallons combined, for Bryant Boilers 1, 2, and 3. The maximum expected operation hours of 6,168 hours per year are based on October 1 to June 14 operation.

Boiler No. 3 has federally enforceable emission limits for PM, SO_2, NO_x, and VOC. Boiler No. 3 utilizes a Joy Turbulaire Impingement Scrubber, Size 125, Type D to control PM emissions. As shown in Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 3. Since there is no control device controlling NO_x, SO_2, or VOC emissions from Boiler No. 3, CAM plans for these pollutants are not required.

1.2.10 BRYANT BOILER NO. 5 (EU 005)

Boiler No. 5 is a vibrating-grate boiler fired with carbonaceous fuel (bagasse) and both new/virgin No. 6 residual fuel oil and on-spec used oil with a maximum sulfur content of 0.7 percent by weight. Boiler No. 5 may burn up to 500 cubic yards per season of soil contaminated with No. 2 and No. 6 oils and on-spec used oil. Boiler No. 5 has a maximum capacity of 342,384 lb/hr steam (1-hour maximum) and a maximum heat input rate of 671 MMBtu/hr (1-hour maximum). The maximum 24-hour heat input rate is 583 MMBtu/hr, with a maximum 24-hour steam rate of 297,482 lb/hr. The design maximum heat input due to No. 6 fuel oil alone is 215.6 MMBtu/hr, corresponding to 1,477 gph of fuel oil. No more than 400,000 gallons of fuel oil can be fired per crop season. The maximum operation hours are 4,572 hours per year, based on October 1 to June 14 operations.

Boiler No. 5 has federally enforceable emission limits for PM, SO_2, and NO_x. Boiler No. 5 utilizes two Joy Turbulaire Impingement Scrubbers, Size 100, Type D to control PM emissions. As shown in

Table 1-1, uncontrolled PM emissions are greater than 100 TPY. Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit; and because uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required for PM for Boiler No. 5. Since there is no control device controlling NO_x or SO_2 emissions from Boiler No. 5, CAM plans for these pollutants are not required.

1.2.11 BRYANT DIESEL GENERATING UNIT NOS. 1 AND 2 (EU 007 AND 008)

The Diesel Generating Unit Nos. 1 and 2 are two 1,000-kilowatts (kW) diesel electric generator sets that are typically used during the sugar off-season, corresponding to a maximum operating period of 1,500 hours per year. Unit No. 1 has a 2-cycle, 1,440 brake horsepower (bhp) engine, Model No. 16-567-B, and Unit No. 2 has a 1,525 bhp engine, Model No. 16-567-C. Both were manufactured by the Cleveland Diesel Engine Division of General Motors Corporation and were installed in 1985. The maximum heat input rate for Unit No. 1 is 12.6 MMBtu/hr and 13.3 MMBtu/hr for Unit No. 2, for a total maximum heat input of 25.9 MMBtu/hr.

The Diesel Generating Unit Nos. 1 and 2 have federally enforceable emission limits for SO_2 and NO_x. However, neither unit has a control device and is, therefore, not subject to CAM.

Table 1-1.
CAM Applicability Determination for U.S. Sugar Clewiston and Bryant Mills

Emission Source	Title V EU ID	Control Equipment	Pollutants with Emission Limits	Uncontrolled Emission Rate (TPY)	CAM Plan Required? (Yes/No)	Comments
CLEWISTON						
Boiler No. 1	001	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
Boiler No. 2	002	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
Boiler No. 4	009	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	SO_2	--	No	No control device.
		None	NO_x	--	No	No control device.
		None	VOC	--	No	No control device.
		None	CO	--	No	No control device.
Boiler No. 7	014	ESP	PM/PM_{10}	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
		None	CO	--	No	No control device.
		None	SAM	--	No	No control device.
Boiler No. 8	028	Separators/ESP	PM/PM_{10}	--	No	Subject to post-1990 NESHAP (Subpart DDDDD).
		SNCR	NO_x	>100	**Yes**	NO_x uncontrolled emissions >100 TPY.
		None	CO	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
		None	HCl	--	No	No control device. Subject to post-1990 NESHAP (Subpart DDDDD).
		None	NH_3	--	No	No control device.
		None	Hg	--	No	No control device. Subject to post-1990 NESHAP (Subpart DDDDD).
VHP Sugar Dryer	015 (S-11)	Baghouse	PM	--	No	Baghouse serves as inherent process equipment.
White Sugar Dryer No. 1	016 (S-10)	Baghouse	PM	--	No	Baghouse serves as inherent process equipment.
Granular Carbon Regneration Furnace	017 (S-12)	Wet Scrubber	PM	99.1 [a]	No	PM uncontrolled emissions <100 TPY.
		None	SO_2	--	No	No control device.
		Afterburner	VOC	55.0 [a]	No	VOC uncontrolled emissions < 100 TPY.
Vacuum Systems						
Screening and Distribution Vacuum	018 (S-1)	Baghouse	PM	186 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
100-lb Bagging Vacuum	018 (S-2)	Baghouse	PM	164 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
5-lb Bagging Vacuum	018 (S-3)	Baghouse	PM	185 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
Conditioning Silos						
Conditioning Silo No. 2	019 (S-7)	Baghouse	PM	3 [a]	No	PM uncontrolled emissions <100 TPY.
Conditioning Silo No. 4	019 (S-8)	Baghouse	PM	3 [a]	No	PM uncontrolled emissions <100 TPY.
Conditioning Silo No. 6	019 (S-9)	Baghouse	PM	3 [a]	No	PM uncontrolled emissions <100 TPY.
Screening and Distribution						
Screening and Distribution #1	020 (S-5)	Baghouse	PM	22 [a]	No	PM uncontrolled emissions <100 TPY.
Screening and Distribution #2	020 (S-6)	Baghouse	PM	34 [a]	No	PM uncontrolled emissions <100 TPY.
Sugar Packaging						
Packaging Dust Collector	022 (S-4)	Baghouse	PM	25 [a]	No	PM uncontrolled emissions <100 TPY.
White Sugar Dryer No. 2	029 (S-13)	Wet Scrubber	PM	505 [a]	**Yes**	PM uncontrolled emissions >100 TPY.
BRYANT						
Boiler No. 1	001	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
Boiler No. 2	002	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
Boiler No. 3	003	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
		None	VOC	--	No	No control device.
Boiler No. 5	005	Wet Scrubber	PM	>100	**Yes**	PM uncontrolled emissions >100 TPY.
		None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
Diesel Generating Unit No. 1	007	None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.
Diesel Generating Unit No. 2	008	None	NO_x	--	No	No control device.
		None	SO_2	--	No	No control device.

[a] Uncontrolled emissions shown in Tables 1-2 and 1-3.

Table 1-2.
Uncontrolled Emissions of PM from the Sugar Refinery Sources, U.S. Sugar Corp., Clewiston

Source/Vent Name	EU No.	Source ID	Refined Sugar Throughput[a] (TPD)	Refined Sugar Throughput[a] (lb/hr)	Refined Sugar Throughput[a] (TPY)	Number of Drop Points	Exhaust Gas Flow (dscfm)	PM Uncontrolled Emission Factor	Particulate Matter (PM) Uncontrolled Emissions (lb/hr)	Particulate Matter (PM) Uncontrolled Emissions (TPY)[b]
V.H.P. Sugar Dryer/Baghouse	015	S-11	2,250	187,500	803,000	--	110,042	14 gr/dscf[c]	13,205	57,838
White Sugar Dryer No. 1/Baghouse	016	S-10	2,250	187,500	803,000	--	94,488	14 gr/dscf[c]	11,339	49,663
Granular Carbon Regeneration Furnace/Wet Scrubber	017	S-12	2,250	187,500	803,000	--	--	see footnote d	22.63[d]	99.12
White Sugar Dryer No. 2/Cyclone(4)/Wet Scrubber	029	S-13	2,250	187,500	803,000	--	96,000	0.14 gr/dscf[g]	115.2	505
<u>Vacuum Systems</u>										
Screening and Distribution Vacuum/Baghouse	018	S-1	2,250	187,500	803,000	--	990	5 gr/dscf[e]	42.43	185.84
100 lb Bagging Vacuum System/Baghouse	018	S-2	2,000	166,667	803,000	--	872	5 gr/dscf[e]	37.37	163.69
5 lb Bagging Vacuum System/Baghouse	018	S-3	2,000	166,667	803,000	--	984	5 gr/dscf[e]	42.17	184.71
<u>Conditioning Silos</u>										
Conditioning Silo No. 2/Baghouse	019	S-7	2,250	187,500	803,000	1	2,641	0.0076 lb/ton[f]	0.71	3.12
Conditioning Silo No. 4/Baghouse	019	S-8	2,250	187,500	803,000	1	2,641	0.0076 lb/ton[f]	0.71	3.12
Conditioning Silo No. 6/Baghouse	019	S-9	2,250	187,500	803,000	1	2,641	0.0076 lb/ton[f]	0.71	3.12
<u>Screening and Distribution</u>										
Screening and Distribution Baghouse #1	020	S-5	2,250	187,500	803,000	7	2,668	0.0076 lb/ton[f]	4.99	21.85
Screening and Distribution Baghouse #2	020	S-6	2,250	187,500	803,000	11	8,735	0.0076 lb/ton[f]	7.84	34.33
<u>Sugar Packaging Baghouse</u>										
Packaging Dust Collector/Baghouse	022	S-4	2,000	166,667	730,000	9	9,589	0.0076 lb/ton[f]	5.70	24.97

[a] Based on amount of sugar produced by the fluidized bed drying system and loaded via
the bulk shipment facility, such that the maximum daily loadout rate is limited to 2,250 TPD.
The amount of refined sugar that could be processed through packaging operations is 2,000 TPD.

[b] Based on 8,760 hr/yr operation.

[c] Based on inlet loading to White Sugar Dryer No. 2 cyclone collectors. These dryers assumed to have the same outlet grain loading.

[d] Based on a 97% control efficiency and an outlet loading of 0.7 lb/hr for the wet scrubber.

[e] Based on estimated grain loading prior to baghouse.

[f] Bulk load-out operations continuous drop emission factors are computed from AP-42 (USEPA, 1995) Section 13.2.4.
E (lb/ton) = k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 ; where U is assumed to be minimum value (1.3 mph) given in AP-42 due to the building enclosure.
M = Moisture Content = 0.25% for refined sugar (minimum AP-42 value).
k = 0.74 for PM.

[g] Grain loading after the cyclones, which are considered inherent process equipment.

Note: lb/hr = pounds per hour.
TPY = tons per year.

Table 1-3.
Uncontrolled Emissions of VOC from the Sugar Refinery Sources, U.S. Sugar Corp., Clewiston

Source/Vent Name	EU No.	Source ID	Uncontrolled VOC Emissions (lb/hr)	Uncontrolled VOC Emissions (TPY) [b]
Granular Carbon Regeneration Furnace/Afterburner	017	S-12	12.50 [a]	54.75

[a] Based on an outlet loading of 1.0 lb/hr and a total VOC destruction efficiency of 92 percent.
[b] Based on operating at 8,760 hr/yr.

Note: lb/hr = pounds per hour.
TPY = tons per year.

2.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 1

2.1 EMISSIONS UNIT IDENTIFICATION

Clewiston Boiler No. 1—EU ID 001

2.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 1 has a PM emission limit of 0.25 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV) plus 0.1 lb/MMBtu for distillate oil [Rule 62-296.410(1)(b)2, F.A.C. and Permit No. 0510003-027-AC]. The equivalent potential emissions are 123.8 lb/hr and 542.0 TPY for carbonaceous fuel and 20.8 lb/hr and 23.6 TPY for distillate oil. The current VE limit is 30 percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit Nos. 0510003-017-AV and 0510003-027-AV, and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 1. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0510003-017-AV).

2.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 1 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 6 to 12 inches of water (in. H_2O). The operating scrubber water inlet pressure to each scrubber is 60 to 130 pounds per square inch gauge (psig). The effectiveness of the wet scrubbers is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU1-I3).

2.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 1	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 6 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 50 gallons per minute (gpm). Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 in. H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

2.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and water flow rate to the Boiler No. 1 wet scrubber. The test data correlating the parameters to the PM emission levels is presented in Figures 2-1 and 2-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 7 in. H_2O
	Minimum parameter value = 7 x 0.9 = 6 in. H_2O
Water Flow Rate:	Minimum test run value = 56 gpm
	Minimum parameter value = 56 x 0.9 = 50 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 1 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly

averages. It is therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 2-1. PM vs. Water Flow
Clewiston Boiler No. 1

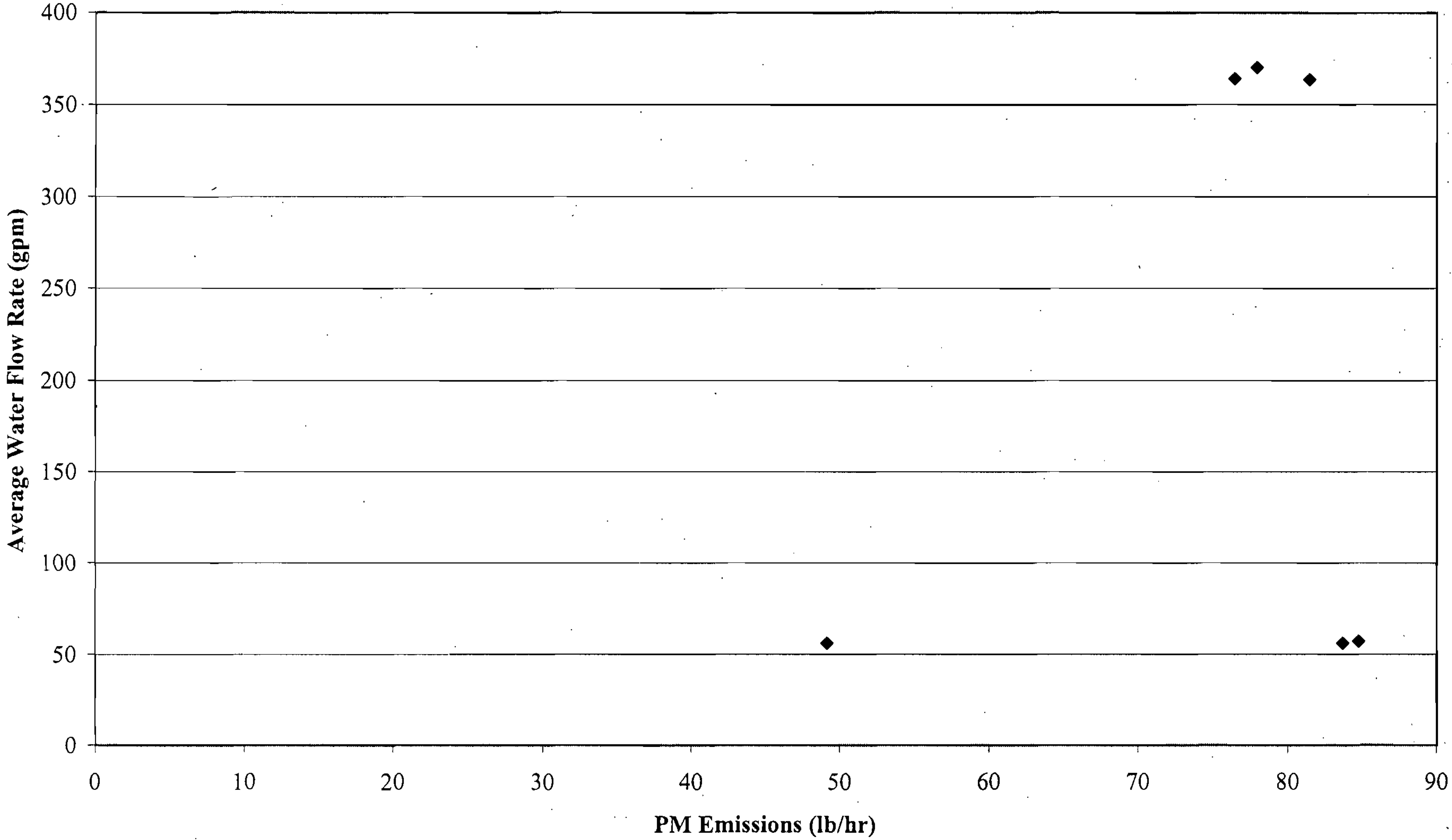
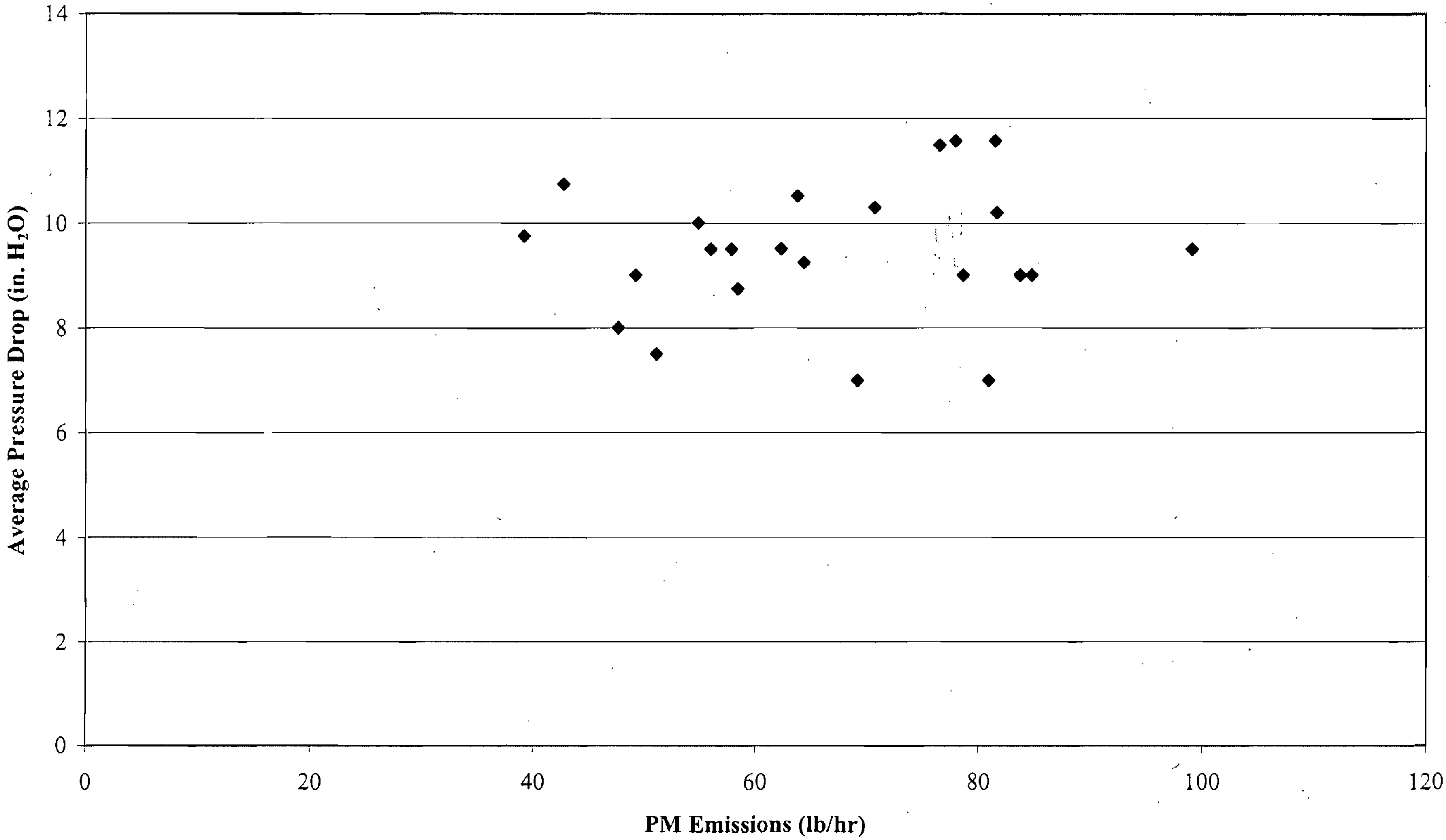


**Figure 2-2. PM vs. Pressure Drop
Clewiston Boiler No. 1**



3.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 2

3.1 EMISSIONS UNIT IDENTIFICATION

Clewiston Boiler No. 2—EU ID 002

3.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 2 has a PM emission limit of 0.25 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV) plus 0.1 lb/MMBtu for distillate oil [Rule 62-296.410(1)(b)2, F.A.C., and Permit No. 0510003-027-AC]. The equivalent potential emissions are 111.8 lb/hr and 490.0 TPY for carbonaceous fuel and 20.8 lb/hr and 23.6 TPY for distillate oil. The current VE limit is 30-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit Nos. 0510003-017-AV and 0510003-027-AV, and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 2. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0510003-017-AV).

3.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 2 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 6 to 12 in. H_2O. The operating scrubber water inlet pressure is 60 to 130 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU2-I3).

3.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 2	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 5 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 58 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 in. H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

3.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and water flow rate to the Boiler No. 2 wet scrubber. The test data correlating the parameters to the PM emission levels is presented in Figures 3-1 and 3-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 6 in. H_2O
	Minimum parameter value = 6 x 0.9 = 5 in. H_2O
Water Flow Rate:	Minimum test run value = 65 gpm
	Minimum parameter value = 65 x 0.9 = 58 gpm

Note that the pressure drop values of 3.0 in H_20, recorded during the January 12, 1998 compliance test as shown in Appendix B, are considered to be outliers and were not used in determining the minimum pressure drop value.

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 2 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly averages. It is therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 3-1. PM vs. Water Flow
Clewiston Boiler No. 2

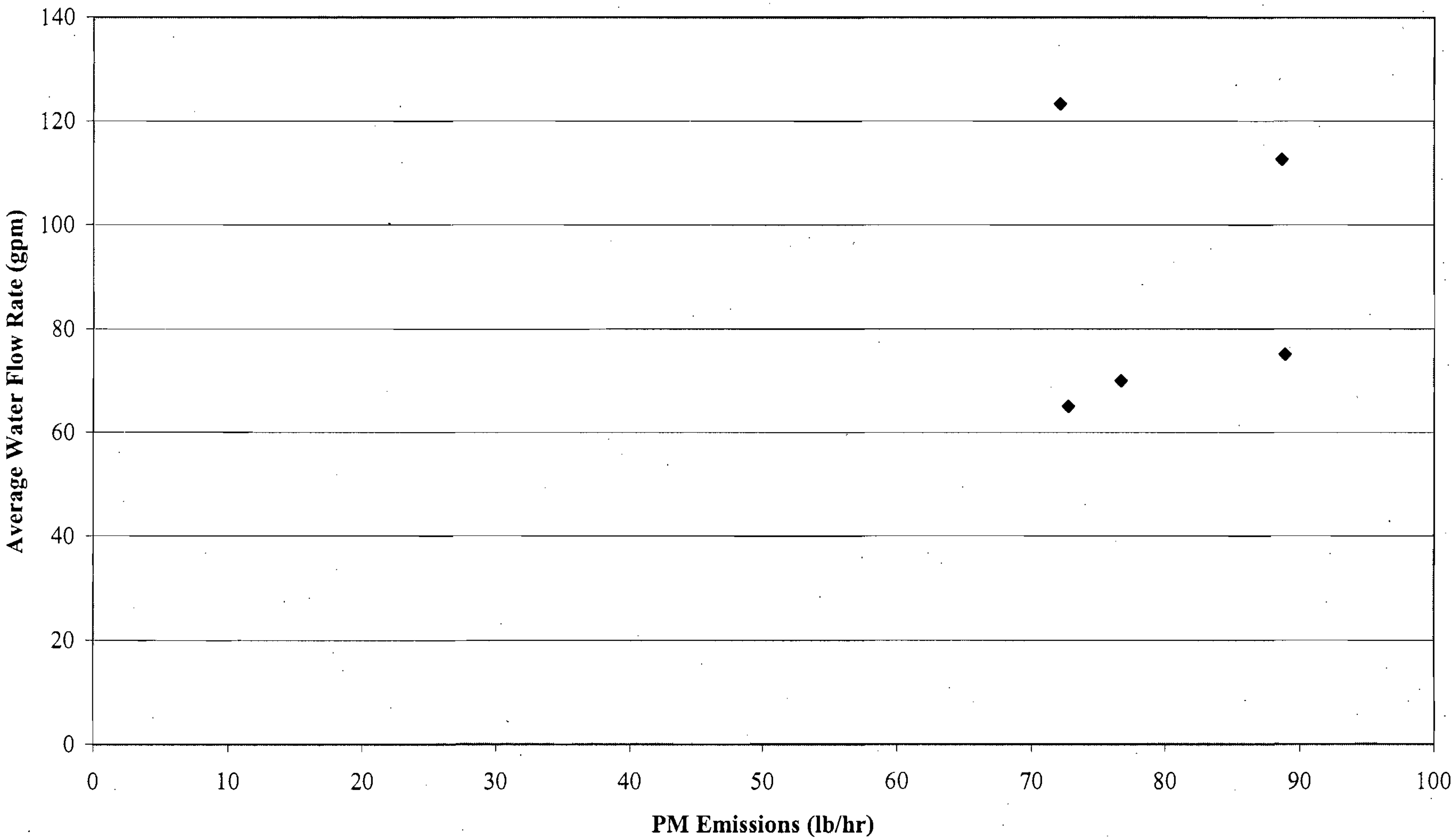
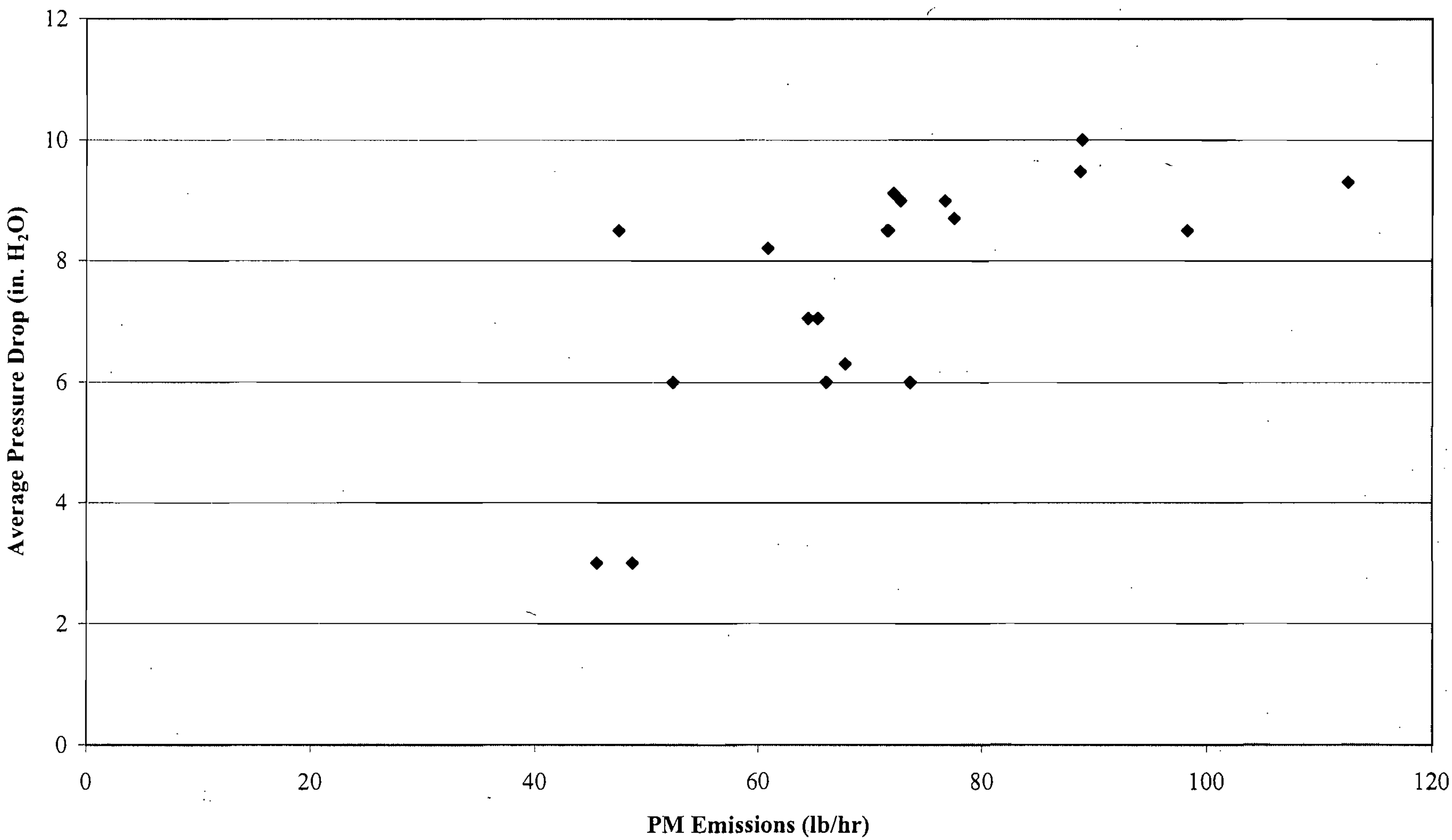


Figure 3-2. PM vs. Pressure Drop
Clewiston Boiler No. 2



4.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 4

4.1 EMISSIONS UNIT IDENTIFICATION

Clewiston Boiler No. 4—EU ID 009

4.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 4 has a PM emission limit of 0.15 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV), plus 0.1 lb/MMBtu for distillate oil [Rule 62-296.406, F.A.C. and Permit No. 0510003-018-AV]. The equivalent potential emissions are 95.0 lb/hr and 216.0 TPY for carbonaceous fuel and 32.6 lb/hr and 3.4 TPY for distillate oil. The current VE limit is 20-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour for carbonaceous fuel (Permit No. 0510003-017-AV), and 20-percent opacity, with an exception of up to 27-percent opacity for 6 minutes per hour for fuel burning (Permit No. 0510003-018-AV).

PM and VE compliance testing is required annually on Boiler No. 4. In addition, the total pressure drop across the scrubber, the scrubber water inlet pressure, and the scrubber water flow rate must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0510003-017-AV).

4.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 4 are controlled by a Joy Turbulaire Impingement Scrubber, Size 200, Type D. The operating pressure drop across the scrubber is 8 to 23 in. H_2O. The operating scrubber water inlet pressure is 40 to 80 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU3-I3).

4.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 4	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 7.6 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 220 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches of water gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

4.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and water flow rate to the Boiler No. 4 wet scrubber. The test data correlating the parameters to the PM emission levels is presented in Figures 4-1 and 4-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 8.5 in. H_2O
	Minimum parameter value = 8.5 x 0.9 = 7.6 in. H_2O
Water Flow Rate:	Minimum test run value = 245 gpm
	Minimum parameter value = 245 x 0.9 = 220 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 4 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four (4) times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

According to the current Title V permit conditions, scrubber parameters should be recorded once every 3 hours. Because the actual emissions have been under the allowable emission rates since 1994 and the boiler data has been within the range of acceptable values for inlet pressure, pressure drop, and water flow rate, a recording frequency of once per 8-hour shift is proposed.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 4-1. PM vs. Water Flow
Clewiston Boiler No. 4

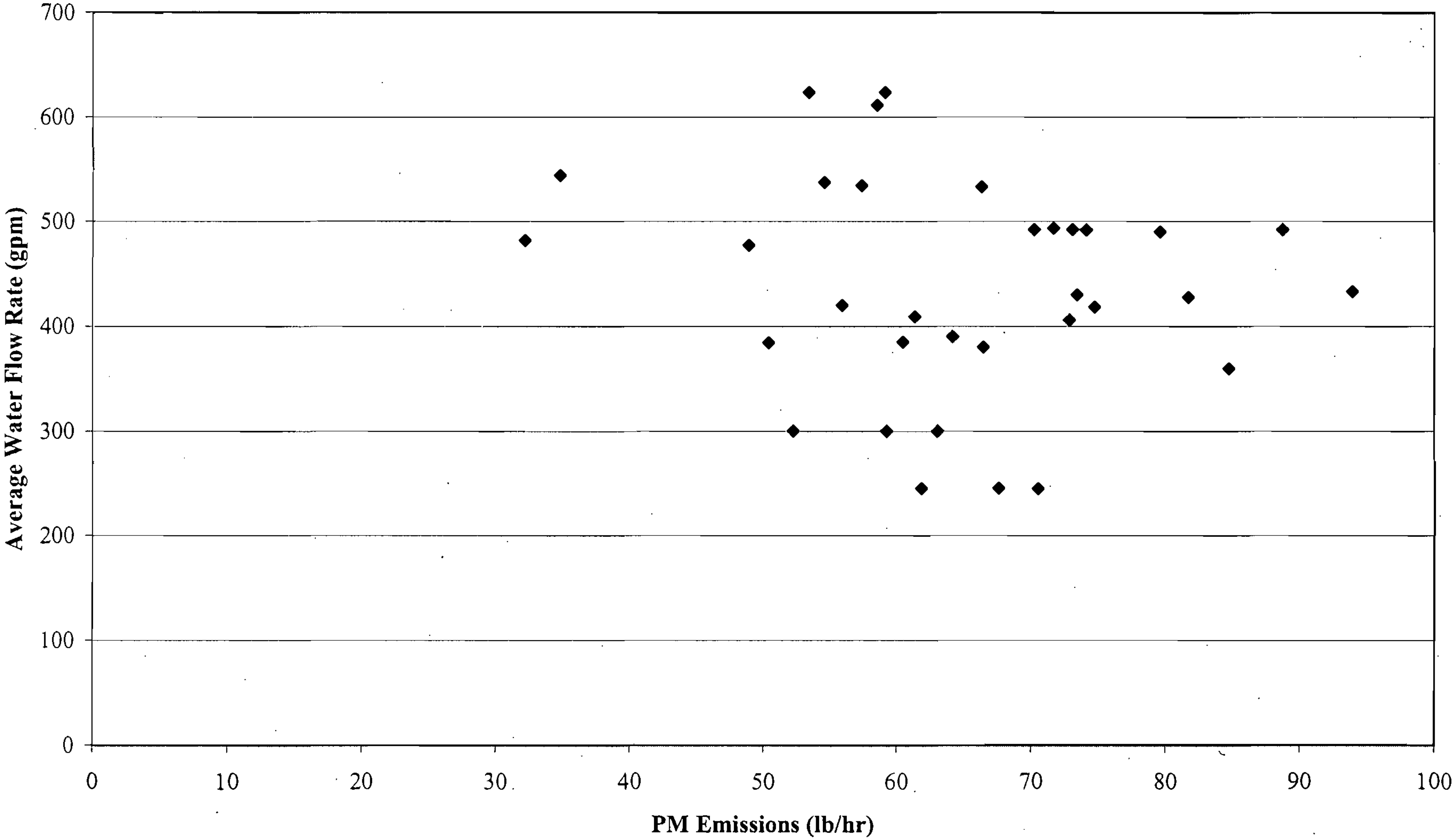
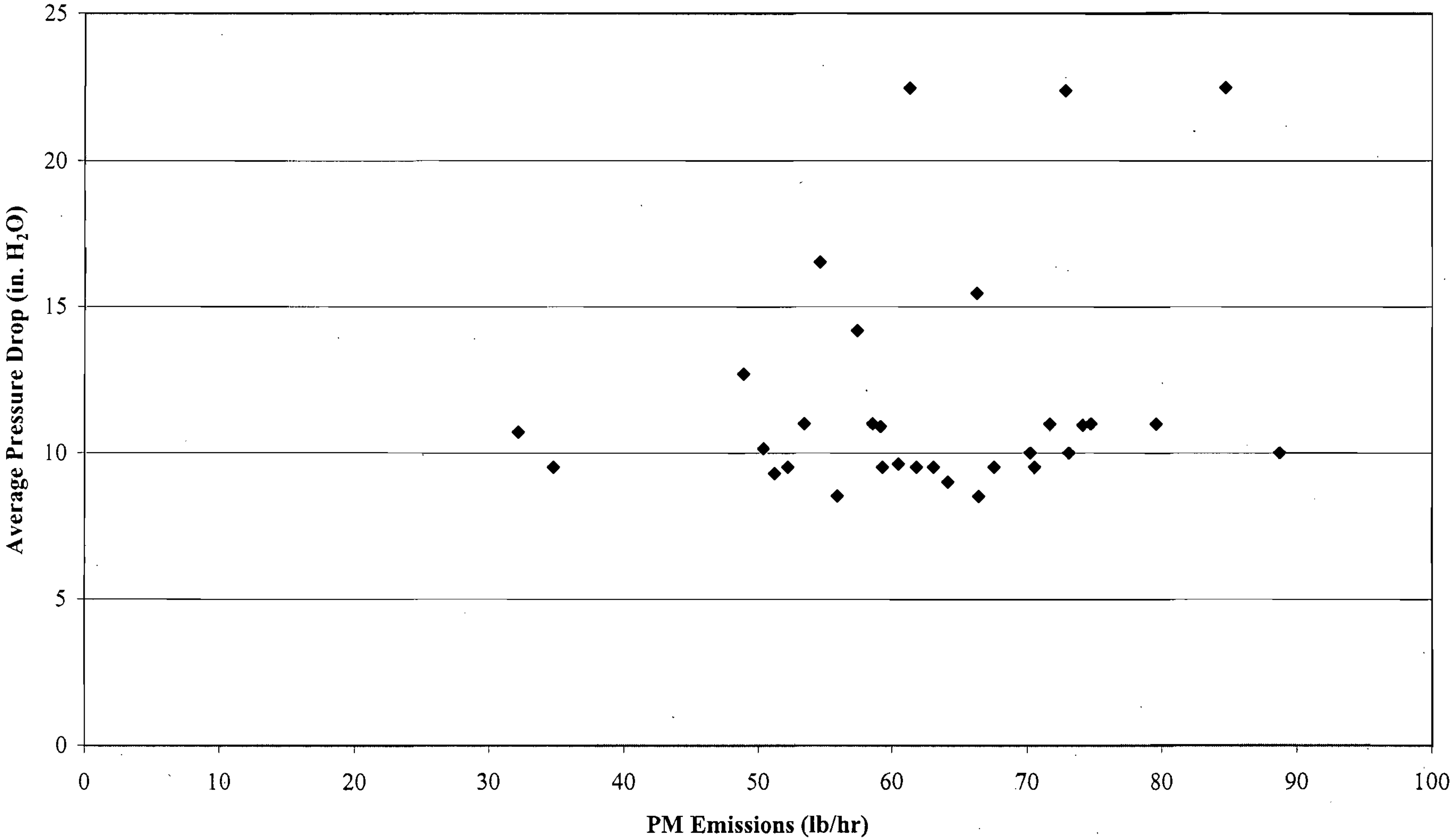


Figure 4-2. PM vs. Pressure Drop
Clewiston Boiler No. 4



5.0 PARTICULATE MATTER EMISSIONS FROM CLEWISTON BOILER NO. 7

5.1 EMISSIONS UNIT IDENTIFICATION

Clewiston Boiler No. 7—EU ID 014

5.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 7 has a PM/PM_{10} emission limit of 0.03 lb/MMBtu for carbonaceous fuel (Permit No. 0510003-017-AV), plus 0.03 lb/MMBtu for No. 2 fuel oil [Rule 62-212.400(5), F.A.C. and Permit No. 0510003-018-AC]. The equivalent PM/PM_{10} potential emissions are 24.4 lb/hr and 97.0 TPY for carbonaceous fuel and 9.8 lb/hr and 9.1 TPY for No. 2 fuel oil. The current VE limit is 20 percent opacity, with an exception of up to 27 percent opacity for 2 minutes per hour when firing carbonaceous fuel [Rule 62-212.400(5), F.A.C. and Permit No. 0510003-017-AV] and 20 percent opacity, with an exception of up to 27 percent opacity for 6 minutes per hour when firing No. 2 fuel oil (Permit No. 0510003-018-AC).

PM/PM_{10} and VE compliance testing is required annually on Boiler No. 7. PM emissions are controlled by an ESP. The wet sand separator is an integral part of Boiler No. 7, since it exists to protect the induced draft fan and is, therefore, not considered a control device. The ESP is considered the PM control device for Boiler No. 7.

5.3 CONTROL TECHNOLOGY DESCRIPTION

As described above, PM/PM_{10} emissions from Boiler No. 7 are controlled by an ESP. The wet sand separator removes sand and partially combusted bagasse fibers to protect the induced draft fan and ESP, and is considered IPE.

The effectiveness of the ESP can be evaluated based on total power input to the ESP. The ESP has a total of three fields. Total power input can be determined by monitoring secondary voltage and secondary current to each field, calculating power input to each field, and summing the individual field values to obtain total power input. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU4-I3).

5.4 MONITORING APPROACH

The monitoring approach is based on monitoring total ESP secondary power input, which is calculated from the ESP secondary voltage and secondary current. The monitoring approach is summarized in the table below.

Boiler No. 7	Indicator No. 1
Indicator	Total Secondary Power Input
Measurement Approach	Total secondary power input to each field is calculated from the secondary current and voltage, which are monitored with an amp/volt meter.
Indicator Range	An excursion is defined as any total power input below 44 kW. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	Accuracy of the amp/volt meter is ±1 milliampere (mA) and ±1 kilovolt (kV).
Verification of Operational Status	NA
QA/QC Practices and Criteria	The amp/volt meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	ESP secondary current and secondary voltage are measured continuously and used to determine the total secondary power input.
Data Collection Procedures	Total power input calculated from voltage and current readings once per 8-hour shift.
Averaging Period	NA

5.5 JUSTIFICATION

Total secondary power input to the ESP is a recognized parameter for controlling PM/PM_{10} emissions, according to 40 CFR 63, Subpart DDDDD. Because the proposed indicator limit is based on test data from a single day, U.S. Sugar may conduct additional testing after the start of the new crop.

U.S. Sugar is choosing to use the historic test data at this time to establish an indicator value for total secondary power input to the Boiler No. 7 ESP. The test data correlating the parameter to the PM emission levels is presented in Figure 5-1. Supporting information is contained in Appendix B

The proposed parameter minimum value is based on 90 percent of the minimum parameter value recorded during the test run, when compliance was demonstrated with the PM/PM_{10} limit. The calculation of the minimum parameter value is provided below:

ESP secondary power input:

Minimum test run value = 49.32 kW

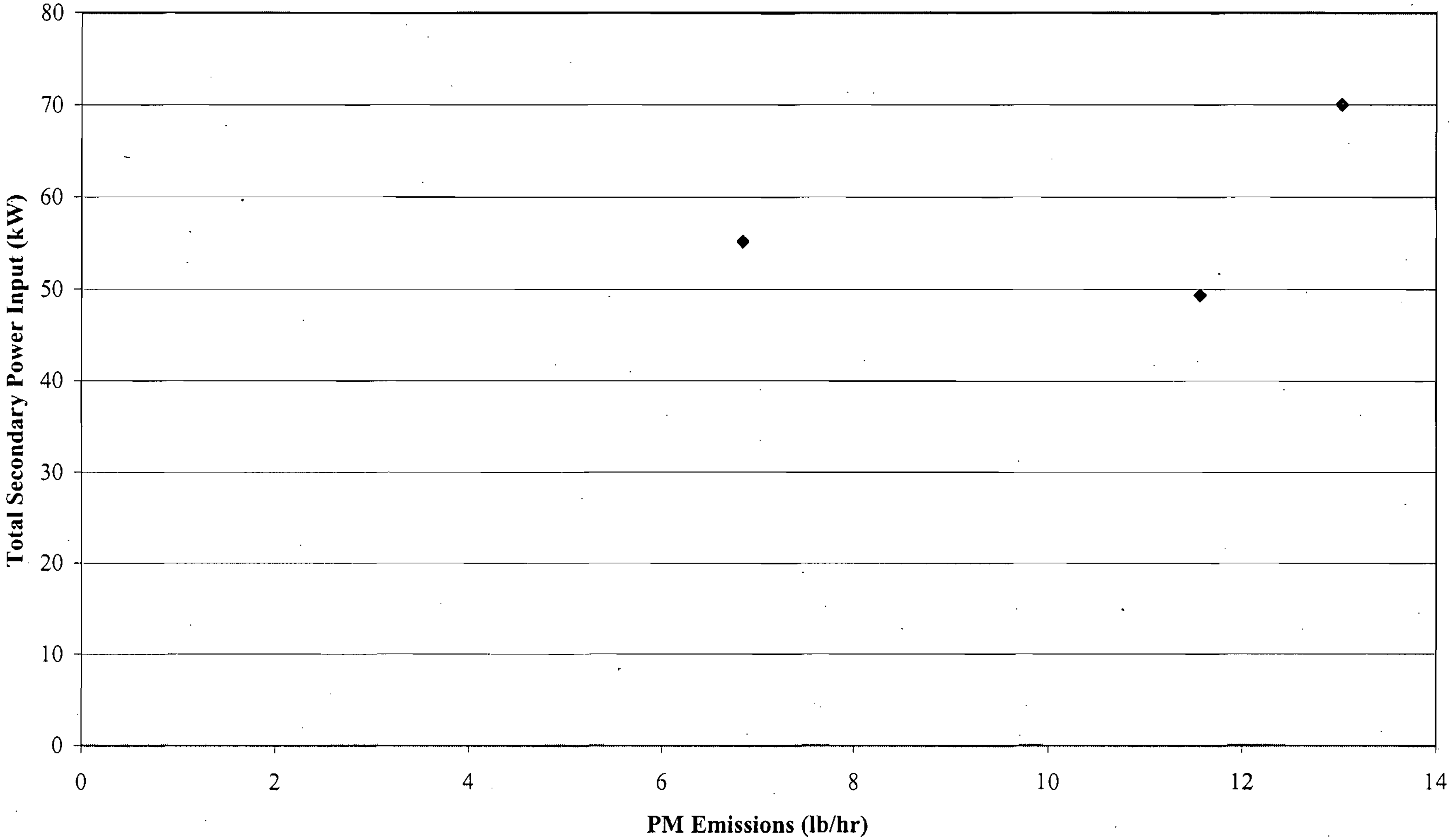
Minimum parameter value = 49.32 x 0.9 = 44 kW

ESP operating parameter values below this minimum parameter value will be indicative of abnormal operation of the control device. This methodology is consistent with the establishment of ESP operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 7 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. The CAM regulations also state that emission units with controlled emissions less than 100 TPY are subject to a reduced data collection frequency of at least once per day [40 CFR 64.3(b)(4)(iii)]. Because Boiler No. 7 has controlled emissions of less than 100 TPY, U.S. Sugar proposes a recording frequency of once per 8-hour shift.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 5-1. PM vs. Power
Clewiston Boiler No. 7



6.0 NITROGEN OXIDE EMISSIONS FROM CLEWISTON BOILER NO. 8

6.1 EMISSIONS UNIT IDENTIFICATION

Clewiston Boiler No. 8—EU ID 028

6.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 8 has a federally enforceable emission limit for NO_x. The NO_x emissions are limited to 0.14 lb/MMBtu (30-day rolling average) (Permit No. 0510003-024-AC/PSD-FL-333A). The equivalent potential emissions are 309 lb/hr and 473.7 TPY.

NO_x compliance testing is required annually on Boiler No. 8. The current permit requires emissions of CO and NO_x to be monitored and recorded by continuous emissions monitoring systems (CEMS) for compliance. According to 40 CFR 64.2 (b)(1)(vi), a CEMS satisfies CAM.

6.3 CONTROL TECHNOLOGY DESCRIPTION

NO_x emissions from Boiler No. 8 are controlled by a SNCR system. The effectiveness of the control equipment is evaluated by a CEMS for NO_x. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU5-I3).

6.4 MONITORING APPROACH

The monitoring approach is based on the CEMS for NO_x and summarized in the table below:

Boiler No. 8	Indicator No. 1
Indicator	CEMS for NO_x.
Measurement Approach	The NO_x emission rate in "lb/MMBtu" is measured at least four times per hour at approximately 15-minute increments, using a CEMS for NO_x.
Indicator Range	An excursion is defined as any 30-day rolling average greater than 0.138 lb/MMBtu. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The CEMS for NO_x measures NO_x in the boiler stack gas.
Verification of Operational Status	NA
QA/QC Practices and Criteria	The CEMS for NO_x meets the requirements of 40 CFR 60, Appendix B, Performance Specification 2.
Monitoring Frequency	NO_x data is measured at least four times per hour at approximately 15-minute increments.
Data Collection Procedures	Hourly averages are calculated from readings at least once every successive 15-minute period.
Averaging Period	24-hour block averages are calculated by averaging all 1-hour averages for each boiler operating day.

6.5 JUSTIFICATION

The CEMS for NO_x provides a direct measurement of the effectiveness of the control system. U.S. Sugar is proposing to use continuous monitoring of the NO_x emissions to satisfy CAM requirements. Because the potential controlled NO_x emissions from Boiler No. 8 are greater than 100 TPY, NO_x emissions must be monitored at least once every 15 minutes. The CEMS meets this requirement.

The SNCR system on Boiler No. 8 generally maintains NO_x emissions at or just below 0.14 lb/MMBtu. However, fuel quality or other conditions may cause the NO_x emissions to go above 0.14 lb/MMBtu for short periods. If the 30-day rolling average NO_x emissions exceed 0.138 lb/MMBtu, this would indicate abnormal operation and constitute an excursion.

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 on a semi-annual basis.

7.0 PM EMISSIONS FROM THE WHITE SUGAR DRYER NO. 2

7.1 EMISSIONS UNIT IDENTIFICATION

White Sugar Dryer No. 2 -- EU ID No. 029

7.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

The White Sugar Dryer No. 2, which dries the sugar following centrifugation and precedes the conditioning silos, has an allowable PM emission limit of 0.005 gr/dscf. The equivalent potential emissions are 4.20 lb/hr and 18.38 TPY. The current VE limit is 10-percent opacity (Permit No. 0510003-026-AC/PSD-FL-346). Refined sugar production is limited to 803,000 TPY.

7.3 CONTROL TECHNOLOGY DESCRIPTION

The White Sugar Dryer No. 2 system contains four (4) cyclone collectors followed by a wet scrubber. The cyclone collectors are considered to be IPE, since they collect sugar product from the dryer and recycle the sugar back to the process. Therefore, PM emissions are controlled by the wet scrubber. The cyclone collector is manufactured by Entoleter, LLC (Model 6600) and the wet scrubber is manufactured by Entoleter, LLC (Centrified Vortex Model 1500). A detailed description of the control equipment is included in the Title V renewal application, Attachment USS-EU6-I3, items l and m.

7.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber water recirculation rate and pressure drop across the wet scrubber. The monitoring approach is summarized in the table below:

White Sugar Dryer No. 2	Indicator No. 1	Indicator No. 2
Indicator	Scrubber water recirculation rate (gpm).	Pressure drop across the scrubber (in. H_20).
Measurement Approach	Scrubber water recirculation rate is monitored with a magnetic flow meter (Rosemount 8732).	Pressure drop is monitored with a manometer.
Indicator Range	Testing needed upon startup of new unit.	Testing needed upon startup of new unit.
Data Representativeness	The monitoring system will consist of a magnetic flow meter located on the scrubber recirculation line. The minimum accuracy of the device is ±5 percent of water flow.	The monitoring system will consist of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device will be ±0.5 in. H_2O gauge pressure.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The flow meter will be maintained in accordance with the manufacturer's recommendations.	The manometer will be maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Water recirculation rate will be monitored continuously.	Pressure drop will be monitored continuously
Data Collection Procedures	Data continuously recorded.	Data continuously recorded.
Averaging Period	Continuous data reduced to 3 hour block average.	Continuous data reduced to 3 hour block average.

7.5 JUSTIFICATION

Both pressure drop across the scrubber and water recirculation rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water recirculation rate is a measure of sufficient scrubbing liquid being supplied to the scrubber.

Because the White Sugar Dryer No. 2 is not yet constructed, U.S. Sugar is proposing to conduct testing at startup. The proposed parameter minimum values will be based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit.

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. An excursion will occur whenever any 3-hour block average is below the minimum parameter value. 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 on a semi-annual basis.

8.0 PM EMISSIONS FROM THE CLEWISTON SUGAR PROCESSING OPERATIONS

8.1 EMISSIONS UNIT IDENTIFICATION

Vacuum Systems – EU ID No. 018

8.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

The Vacuum Systems, which collect dust from the screening/distribution bins and packaging, have a PM emission limit of 0.18 lb/hr. The equivalent potential annual emissions are 0.84 TPY (Permit No. 0510003-010-AC/PSD-FL-272A).

FDEP has waived the PM compliance test requirements and has specified the alternative standard of 5-percent opacity (6-minute average) as the method for demonstrating compliance for this source.

8.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from the Vacuum Systems are controlled by three Hoffman (HPC-44120) baghouses. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU6-I3, items e, f and g).

8.4 MONITORING APPROACH

The monitoring approach is based on monitoring VE from the Clewiston Mill Sugar Processing Operation baghouses. The monitoring approach is summarized in the table below:

Sugar Processing Operations	Indicator No. 1
Indicator	Daily 1 minute VE observation for each baghouse.
Measurement Approach	VE are observed by an observer who is knowledgeable in VE, but who does not have to be a certified VE observer.
Indicator Range	An excursion is defined as any VE. If VE are observed, further investigation of the effectiveness of the baghouses will be performed.
Data Representativeness	VE observation according to EPA Method 22.
Verification of Operational Status	Operational status of each source will be verified prior to observing the VE.
QA/QC Practices and Criteria	VE will be determined based on 40 CFR 60, Appendix A – Method 22.
Monitoring Frequency	VE will be observed once a day for one (1) minute for each source.
Data Collection Procedures	Daily VE observations will be recorded in a log.
Averaging Period	NA

8.5 JUSTIFICATION

Uncontrolled PM emissions from the Vacuum Systems are greater than 100 TPY, but controlled PM emissions are less than 100 TPY. According to CAM regulations [40 CFR 64.3(b)(4)(iii)], the minimum frequency of data collection for emission-specific units emitting less than 100 TPY of controlled emissions is once per day. It is therefore proposed that a daily VE observation be conducted on each baghouse for a one-minute period, based on EPA Method 22 (40 CFR 60, Appendix A) for EU No. 018.

EPA Method 22 does not require the opacity of emissions be determined, and does not require the use of a certified VE reader. However, the observer, at a minimum, must be knowledgeable regarding influences on the visibility of emissions. U.S. Sugar will instruct its VE observers in the requirements and procedures for Method 22. If any VEs are observed, then further investigation will be performed to ensure the baghouses are operating correctly.

9.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 1

9.1 EMISSIONS UNIT IDENTIFICATION

Bryant Boiler No. 1 -- EU ID 001

9.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 1 has a PM emission limit of 0.3 lb/MMBtu for carbonaceous fuel [Rule 62 296.410(1)(b)2, F.A.C. and Permit No. 0990061-006-AV] plus 0.1 lb/MMBtu for No 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C. and Permit No. 0990061-006-AV]. The equivalent potential emissions are 115.5 lb/hr and 356.2 TPY for carbonaceous fuel and 18.9 lb/hr and 58.3 TPY for No. 6 fuel oil. The current VE limit is 30-percent opacity, with an exception of up to 40 percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 1. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0990061-006-AV).

9.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 1 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 5 to 10 inches H_2O. The operating scrubber water inlet pressure to the scrubber is 48 to 60 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU7-I3).

9.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 1	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 4.5 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 200 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 inches of water gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

9.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and total water flow rate to the Boiler No. 1 wet scrubber. The test data correlating the parameters to the PM emission levels are presented in Figures 9-1 through 9-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 5 in. H_2O
	Minimum parameter value = 5 x 0.9 = 4.5 in. H_2O
Water Flow Rate:	Minimum test run value = 225 gpm
	Minimum parameter value = 225 x 0.9 = 202 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 1 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four (4) times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly

averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 9-1. PM vs. Water Flow
Bryant Boiler No. 1

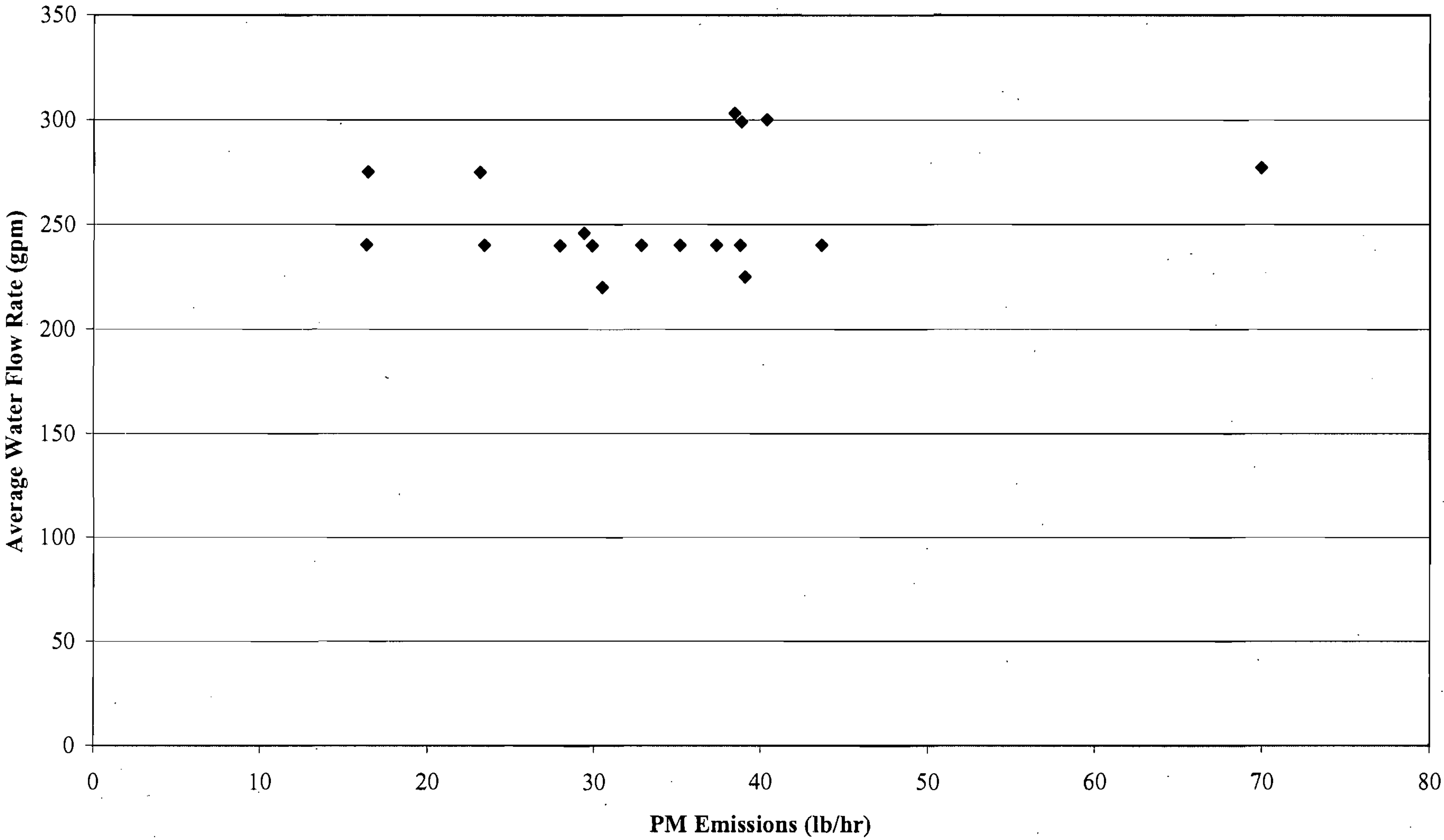
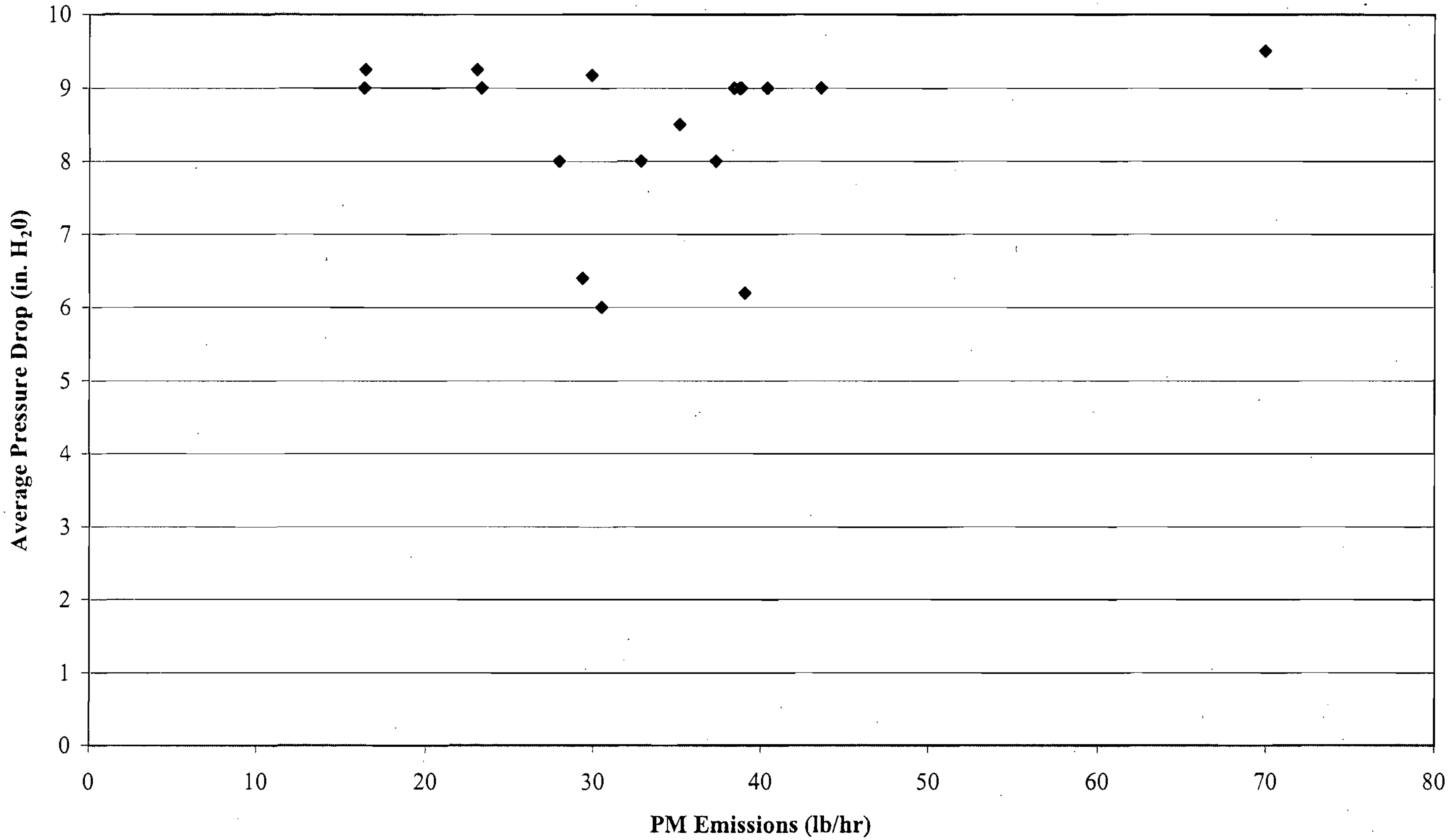


Figure 9-2. PM vs. Pressure Drop
Bryant Boiler No. 1



10.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 2

10.1 EMISSIONS UNIT IDENTIFICATION

Bryant Boiler No. 2 - EU ID 002

10.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 2 has a PM emission limit of 0.3 lb/MMBtu for carbonaceous fuel [Rule 62 296.410(1)(b)2, F.A.C., and Permit No. 0990061-006-AV] plus 0.1 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C. and Permit No. 0990061-006-AV]. The equivalent potential emissions are 115.5 lb/hr and 356.2 TPY for carbonaceous fuel and 18.9 lb/hr and 58.3 TPY for No. 6 fuel oil. The current VE limit is 30-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 2. In addition, the total pressure drop across each scrubber and the water inlet pressure at each scrubber must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration or repair (Permit No. 0990061-006-AV).

10.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 2 are controlled by two Joy Turbulaire Impingement Scrubbers, Size 40, Type D. The operating pressure drop across each scrubber is 4 to 8 in. H_2O. The operating scrubber water inlet pressure to each scrubber is 48 to 60 psig. The effectiveness of the wet scrubbers is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU8-I3).

10.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 2	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across each scrubber.	Total water flow rate to each scrubber.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 3.6 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 200 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 in. H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

10.5 JUSTIFICATION

Both pressure drop across each scrubber and water flow rate to each scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubbers.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubbers. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubbers. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and total water flow rate to the Boiler No. 2 wet scrubbers. The test data correlating the parameters to the PM emission levels are presented in Figures 10-1 through 10-3. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 4 in. H_2O
	Minimum parameter value = 4 x 0.9 = 3.6 in. H_2O
Water Flow Rate:	Minimum test run value = 225 gpm
	Minimum parameter value = 225 x 0.9 = 203 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 2 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly

averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 10-1. PM vs. Water Flow
Bryant Boiler No. 2

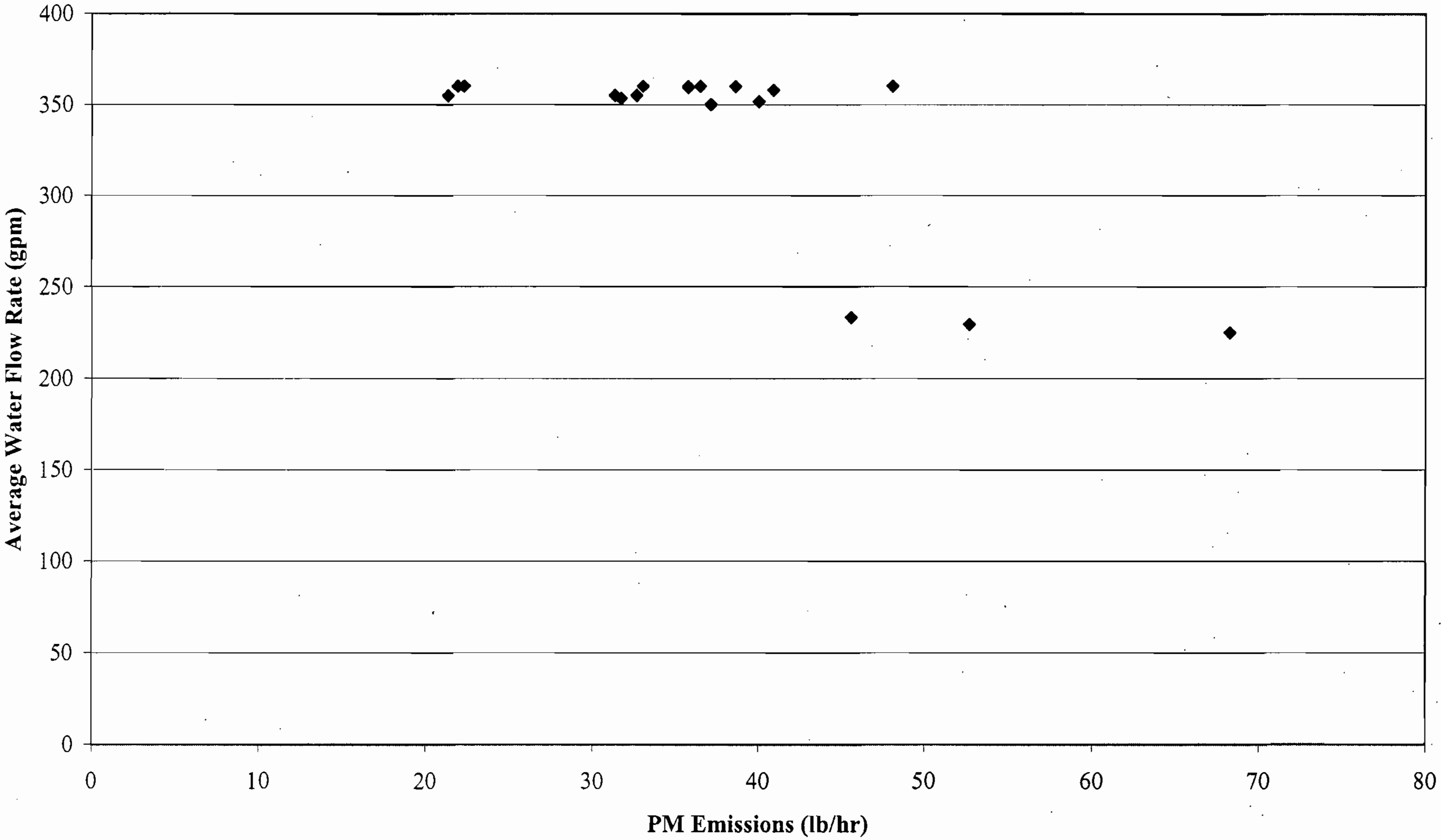


Figure 10-2. PM vs. Pressure Drop
Bryant Boiler No. 2 (North Scrubber)

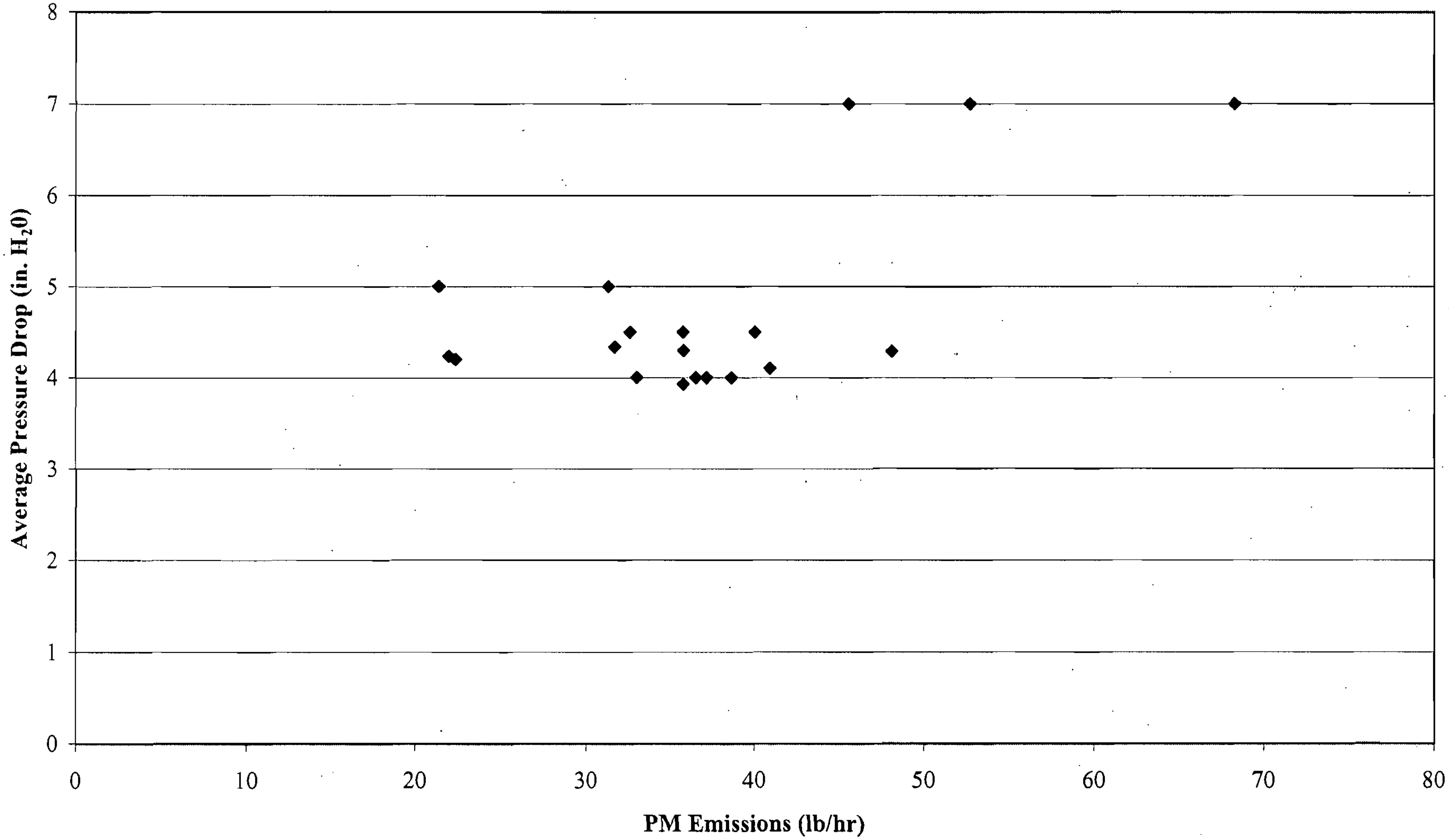
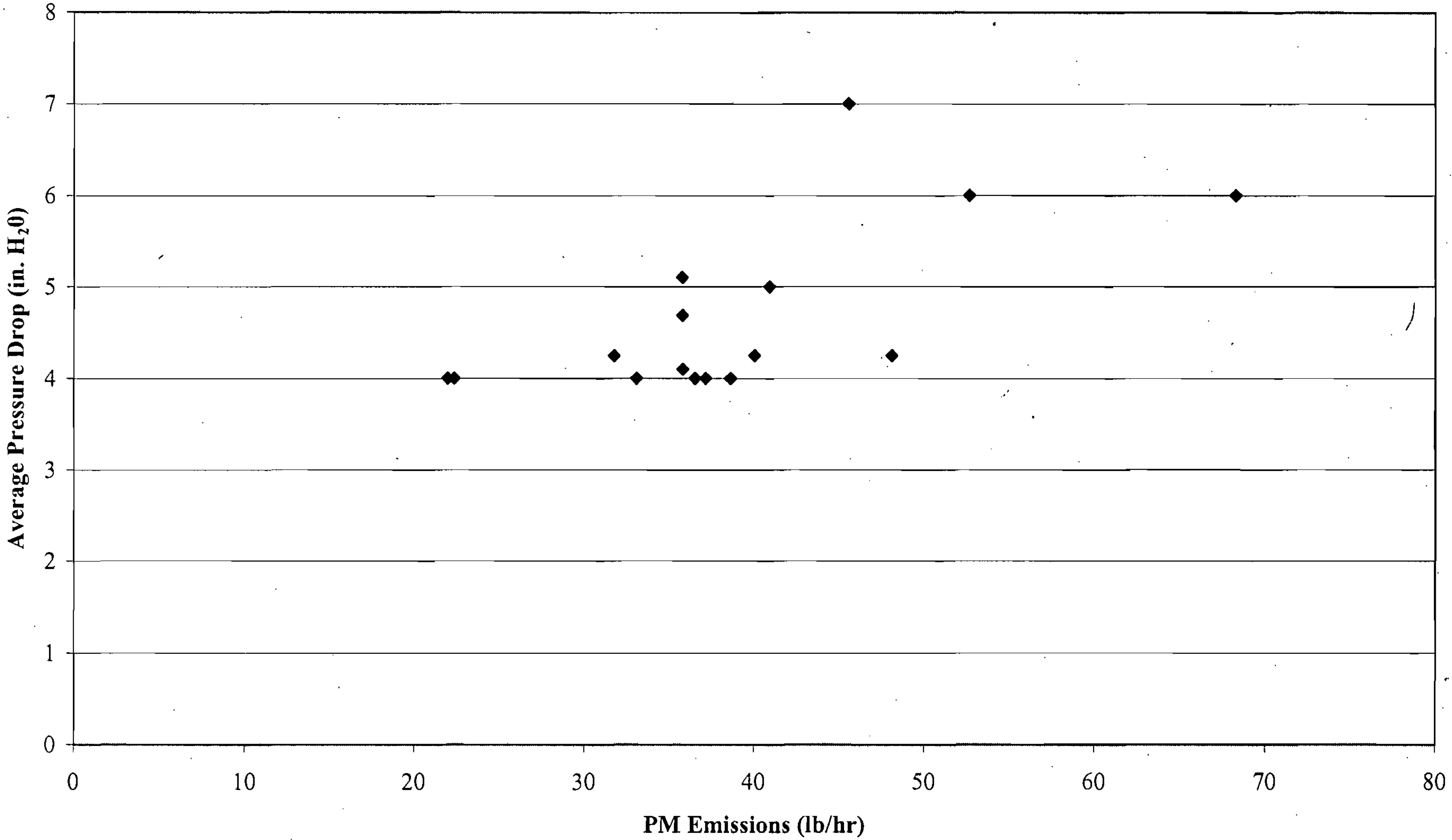


Figure 10-3. PM vs. Pressure Drop
Bryant Boiler No. 2 (South Scrubber)



11.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 3

11.1 EMISSIONS UNIT IDENTIFICATION

Bryant Boiler No. 3 - EU ID 003

11.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 3 has a PM emission limit of 0.3 lb/MMBtu for carbonaceous fuel [Rule 62 296.410(1)(b)2, F.A.C., and Permit No. 0990061-006-AV] plus 0.1 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C., and Permit No. 0990061-006-AV]. The equivalent potential emissions are 115.5 lb/hr and 356.2 TPY for carbonaceous fuel and 18.9 lb/hr and 58.3 TPY for No. 6 fuel oil. The current VE limit is 30-percent opacity, with an exception of up to 40 percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 3. In addition, the total pressure drop across the scrubber and the scrubber water inlet pressure must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration or repair (Permit No. 0990061-006-AV).

11.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 3 are controlled by a Joy Turbulaire Impingement Scrubber, Size 125, Type D. The operating pressure drop across the scrubber is 6 to 8 in. H_2O. The operating scrubber water inlet pressure is 48 to 60 psig. The effectiveness of the wet scrubber is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU9-I3).

11.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 3	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across the scrubber.	Total water flow rate to the scrubber.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 5.4 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any water flow rate below 216 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 in. H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

11.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubber.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and total water flow rate to the Boiler No. 3 wet scrubber. The test data correlating the parameters to the PM emission levels are presented in Figures 11-1 and 11-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 6 in. H_2O
	Minimum parameter value = 6 x 0.9 = 5.4 in. H_2O
Water Flow Rate:	Minimum test run value = 240 gpm
	Minimum parameter value = 240 x 0.9 = 216 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubber. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 3 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly

averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 11-1. PM vs. Water Flow
Bryant Boiler No. 3

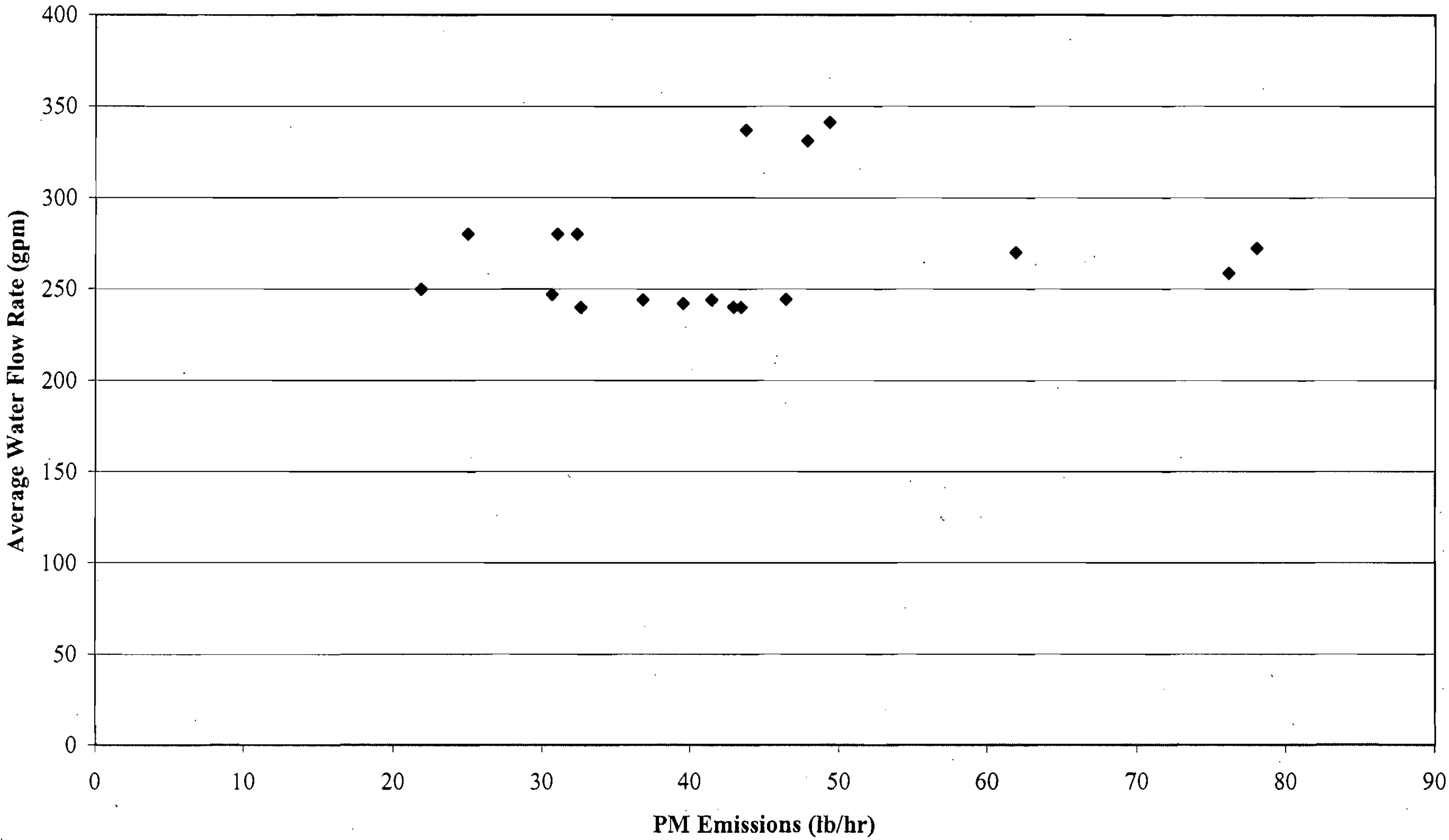
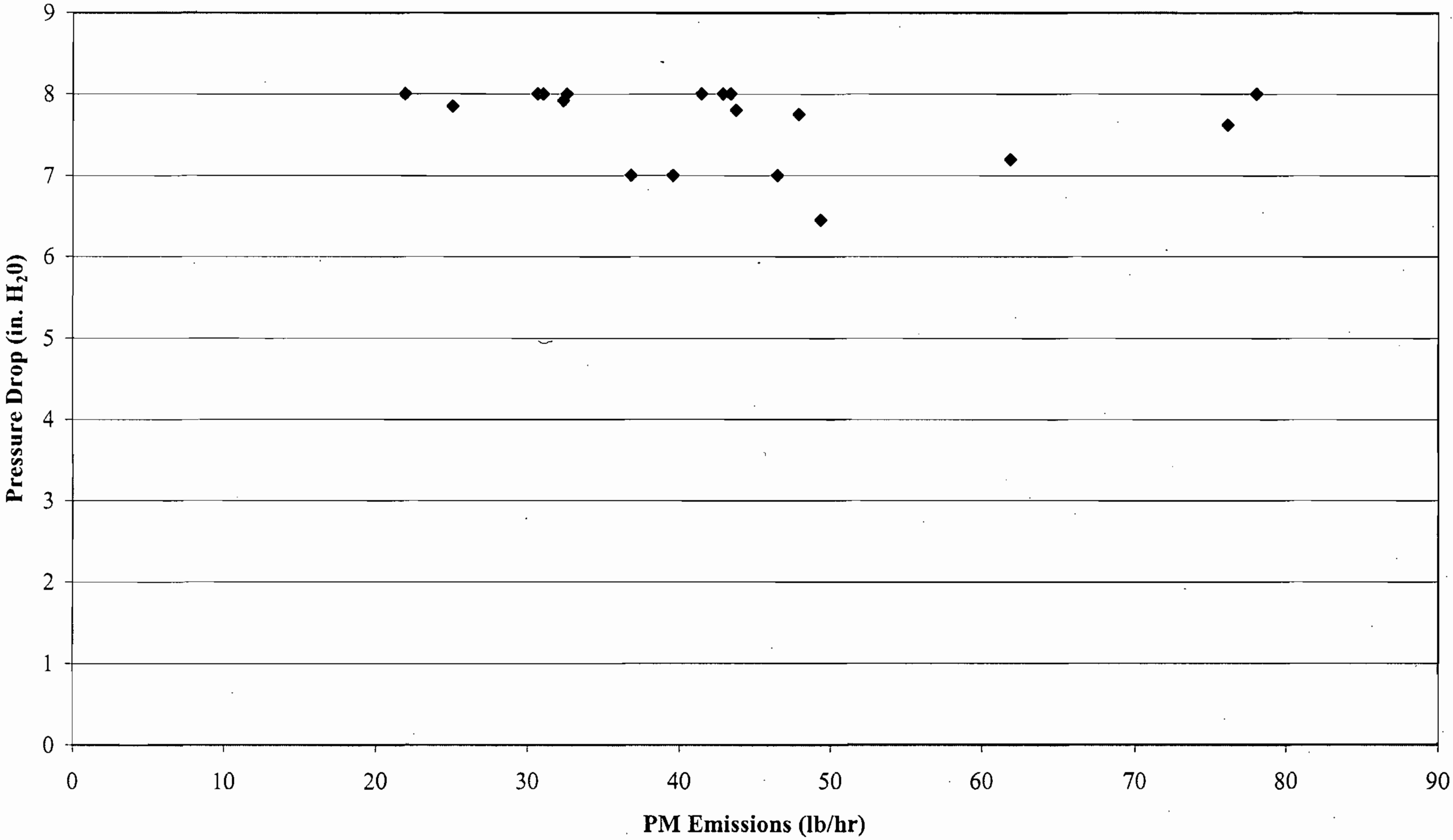


Figure 11-2. PM vs. Pressure Drop
Bryant Boiler No. 3



12.0 PARTICULATE MATTER EMISSIONS FROM BRYANT BOILER NO. 5

12.1 EMISSIONS UNIT IDENTIFICATION

Bryant Boiler No. 5 - EU ID 005

12.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 5 has a PM emission limit of 0.15 lb/MMBtu for carbonaceous fuel plus 0.1 lb/MMBtu for No. 6 fuel oil (Permit No. 0990061-006-AV). The equivalent potential emissions are 100.7 lb/hr and 154.3 TPY for carbonaceous fuel and 21.6 lb/hr and 2.9 TPY for No. 6 fuel oil. The current VE limit is 20-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour [Permit No. 0990061-006-AV and Rule 62-296.410(1)(b)1, F.A.C.].

PM and VE compliance testing is required annually on Boiler No. 5. In addition, the total pressure drop across the scrubber, the scrubber water inlet pressure, and the scrubber water supply flow rate must be monitored and recorded at least once per 8-hour shift during each day of operation. The monitors must be properly maintained and functional at all times, except during instrument breakdown, calibration, or repair (Permit No. 0990061-006-AV).

12.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 5 are controlled by two Joy Turbulaire Impingement Scrubbers, Size 100, Type D. The operating pressure drop across each scrubber is 8 to 14 in. H_2O. The operating scrubber water inlet pressure to each scrubber is 46 to 63 psig. The effectiveness of the wet scrubbers is evaluated with an annual stack test and VE measurements. A detailed description of the control equipment is included in the Title V renewal application (Attachment USS-EU10-I3).

12.4 MONITORING APPROACH

The monitoring approach is based on monitoring scrubber pressure drop and scrubber water flow rate. The monitoring approach is summarized in the table below:

Boiler No. 5	Indicator No. 1	Indicator No. 2
Indicator	Pressure drop across each scrubber.	Total water flow rate to the scrubbers.
Measurement Approach	Pressure drop is monitored with a manometer.	The scrubber water flow rate is measured using a flow meter.
Indicator Range	An excursion is defined as any pressure drop below 7.2 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any total water flow rate below 765 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a manometer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.5 in. H_2O gauge pressure.	The scrubber water flow meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5 percent of total water flow.
Verification of Operational Status	NA	NA
QA/QC Practices and Criteria	The manometer is maintained in accordance with the manufacturer's recommendations.	The flow meter is maintained in accordance with the manufacturer's recommendations.
Monitoring Frequency	Pressure drop is monitored continuously.	Scrubber water flow rate is monitored continuously.
Data Collection Procedures	Reading taken once every 8 hours and recorded in log.	Reading taken once every 8 hours and recorded in log.
Averaging Period	NA	NA

12.5 JUSTIFICATION

Both pressure drop across the scrubbers and water flow rate to the scrubbers are recognized parameters for controlling PM emissions with wet scrubbers. The pressure drop is a measure of the energy imparted to the gas stream and, therefore, the efficiency of the scrubbing process. The water flow rate is a measure of sufficient fresh scrubbing liquid being supplied to the scrubbers.

Water delivery pressure is currently monitored, which provides an indication of plugging of the spray nozzles in the scrubber. However, scrubber water flow rate provides a more direct indicator of adequate water supply to the scrubber. Therefore, water delivery pressure is not proposed as a parameter for CAM purposes.

U.S. Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and total water flow rate to the Boiler No. 5 wet scrubbers. The test data correlating the parameters to the PM emission levels are presented in Figures 12-1 through 12-3. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values recorded during the test runs, using the historic test data, when compliance was demonstrated with the PM limit. The calculations of the minimum parameter values are provided below:

Pressure Drop:	Minimum test run value = 8 in. H_2O
	Minimum parameter value = 8 x 0.9 = 7.2 in. H_2O
Water Flow Rate:	Minimum test run value = 850 gpm
	Minimum parameter value = 850 x 0.9 = 765 gpm

Wet scrubber operating parameter values below these minimum parameter values are indicative of abnormal operation of the wet scrubbers. This methodology is consistent with the establishment of wet scrubber operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater MACT standards. Boiler No. 5 will be subject to these standards beginning in September 2007.

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 TPY collect monitoring data at least four times per hour. However, 40 CFR 64.3(b)(4)(ii) allows the permitting authority to approve a reduced data collection frequency, if appropriate, based on the data collection mechanisms available for a particular parameter.

U.S. Sugar has been recording scrubber parameters once every 8-hour shift, according to the current Title V permit conditions. Although U.S. Sugar has continuous pressure drop and water flow rate monitors in place, the mechanisms are not in place to continuously record the data and create hourly

averages. It is, therefore, requested that the current recording frequency of once per 8-hour shift be retained.

Based on collecting data once per 8-hour shift, an excursion will occur whenever any individual reading is below the minimum parameter value. 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 on a semi-annual basis.

Figure 12-1. PM vs. Water Flow
Bryant Boiler No. 5

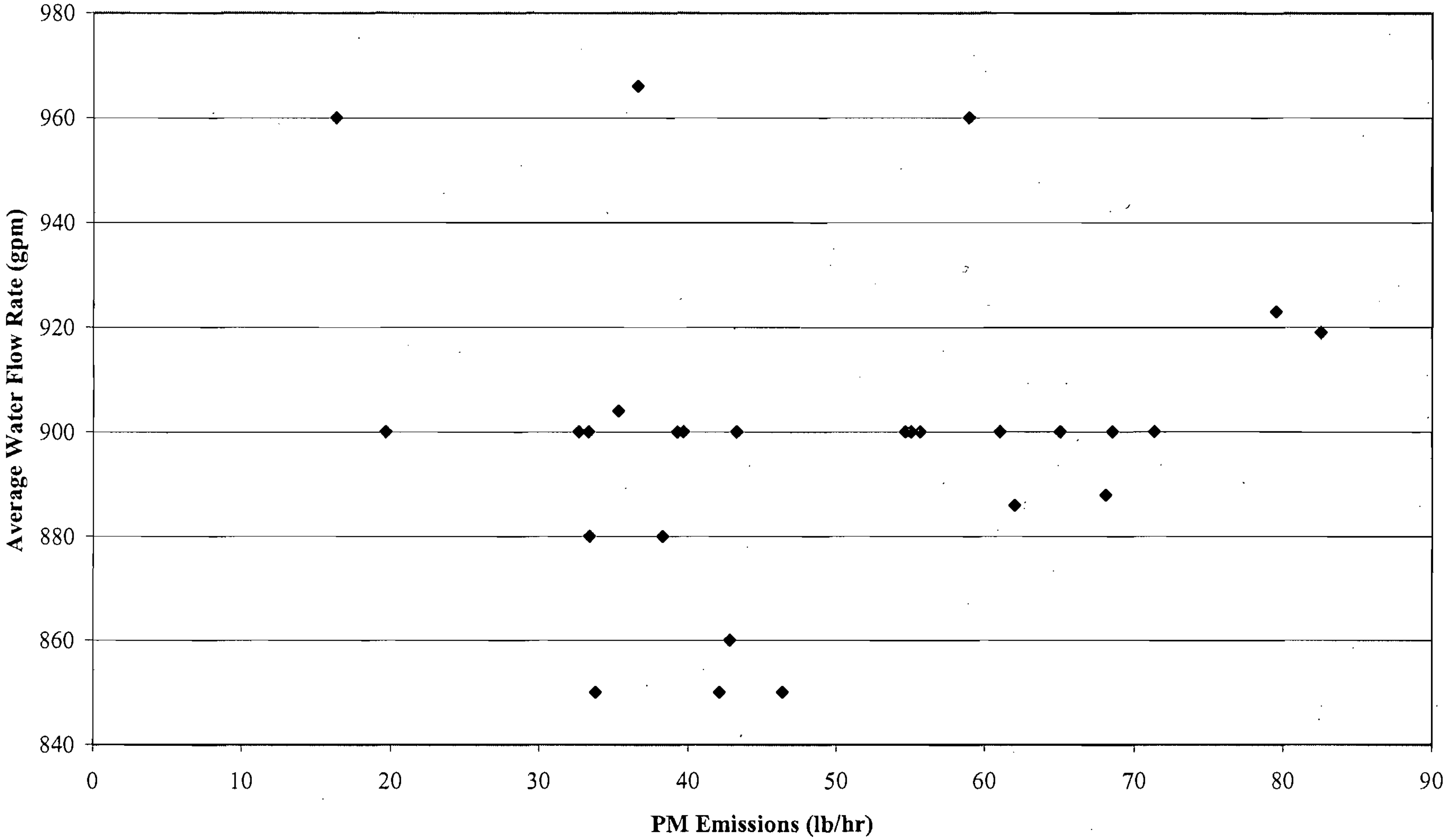


Figure 12-2. PM vs. Pressure Drop
Bryant Boiler No. 5 (North Scrubber)

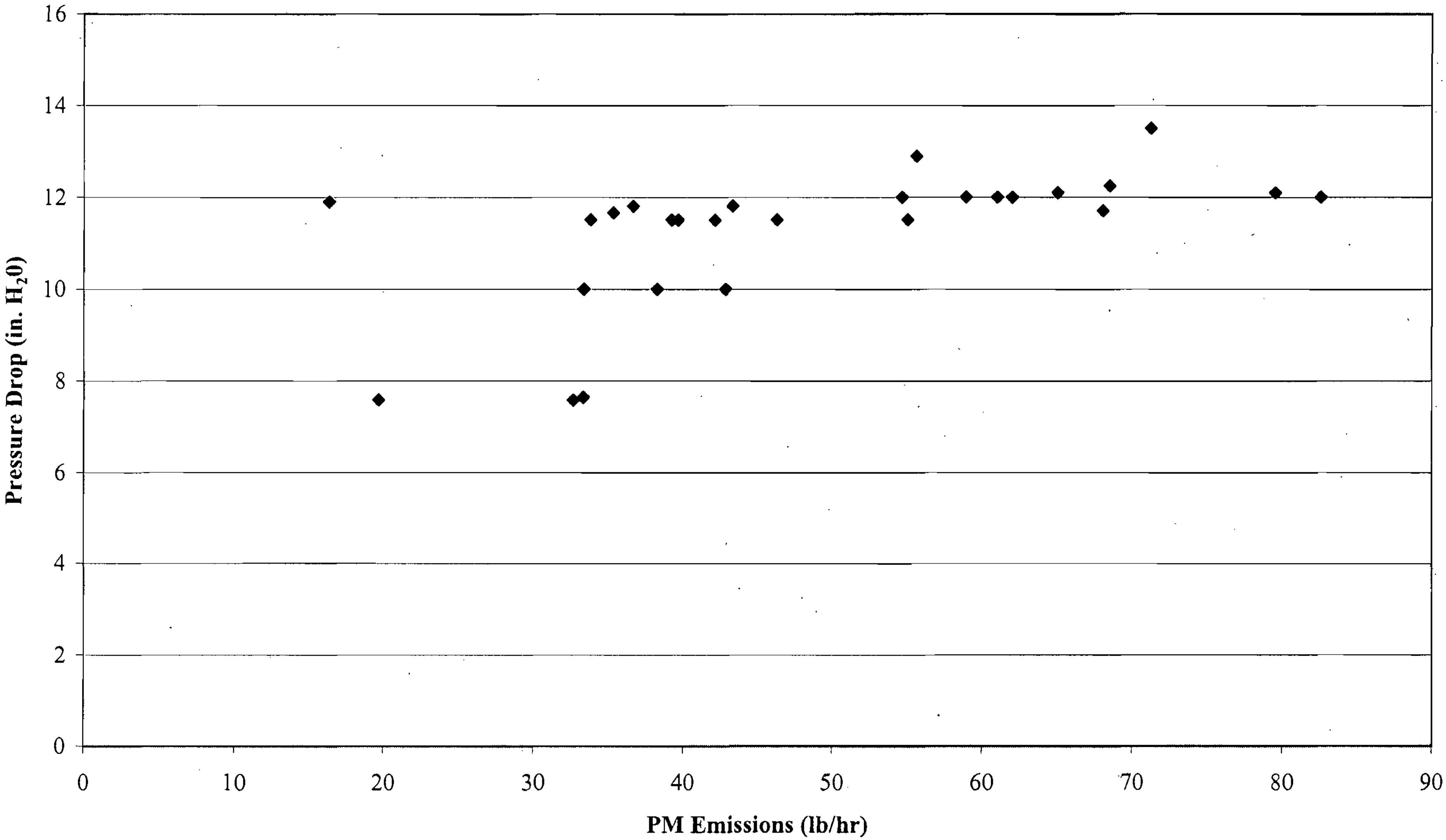
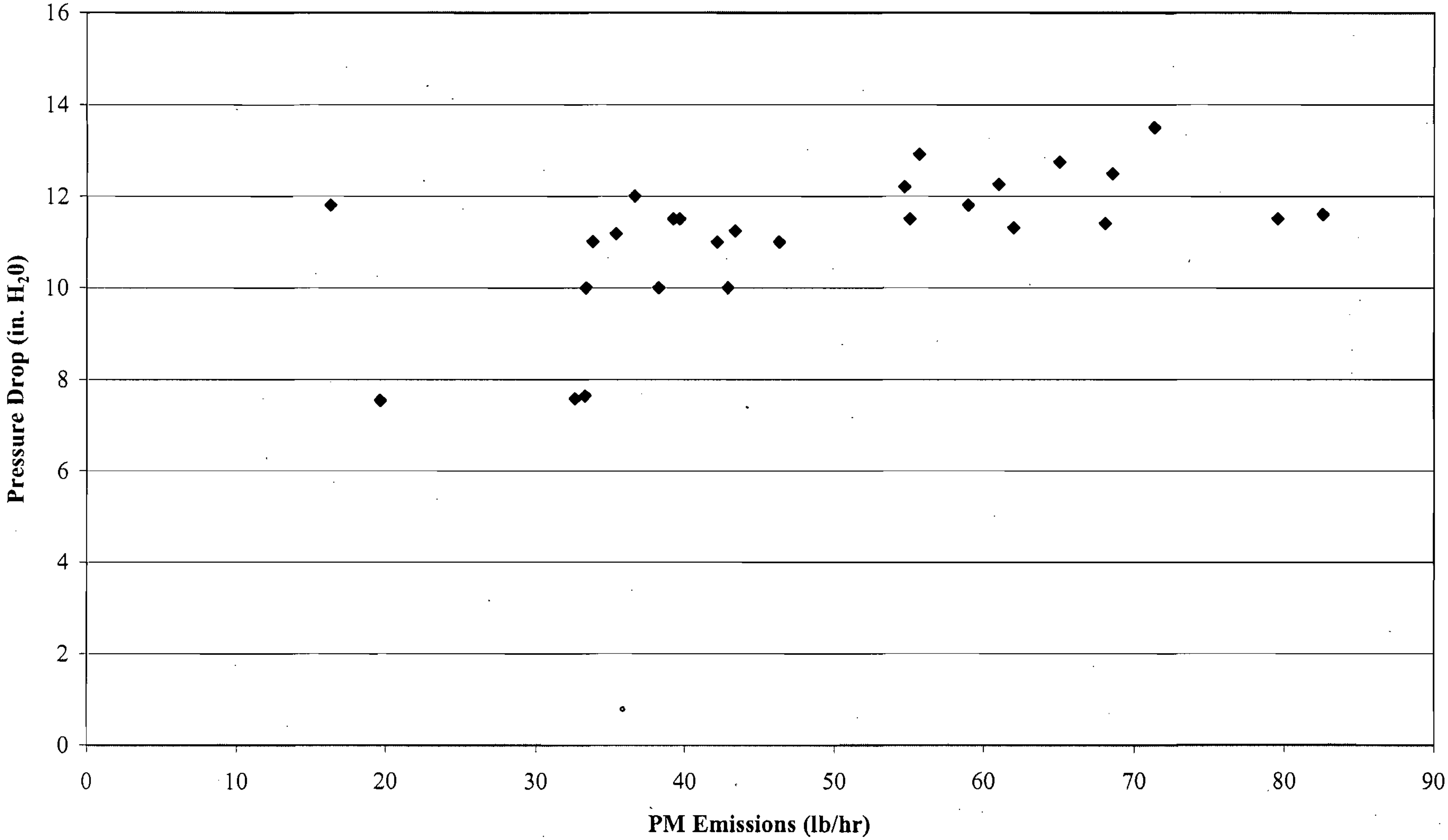


Figure 12-3. PM vs. Pressure Drop
Bryant Boiler No. 5 (South Scrubber)



APPENDIX A

SIGNATURE PAGES

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
   William A. Raiola, Senior Vice President, Sugar Processing Operations

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - [x] For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - [ ] For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - [ ] For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - [ ] The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: **United States Sugar Corporation**
   Street Address: **111 Ponce de Leon Avenue**
   City: **Clewiston** State: **Florida** Zip Code: **33440**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**

5. Application Responsible Official Email Address: **braiola@ussugar.com**

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   [signature] 9-22-05

   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☒, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff — 9/22/05

Signature — Date

(seal)

* Attach any exception to certification statement.

** **Board of Professional Engineers Certificate of Authorization #00001670**

APPENDIX B

HISTORIC PM COMPLIANCE TEST DATA

Table B-1. Boiler PM Emission Tests, Clewiston

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate[1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
Boiler 1	1	Vibrating Grate	01/16/96	113,127	183,707	194,211	410.0	56.94	102.49	0.250	99.14	0.242			9.5
Boiler 1	2	Vibrating Grate	01/16/96	117,058	187,835	202,025	426.0	59.17	106.50	0.250	64.43	0.151			9.3
Boiler 1	3	Vibrating Grate	01/16/96	118,730	191,603	219,200	461.0	64.02	115.24	0.250	67.68	0.147			
Boiler 1	1	Vibrating Grate	01/07/97	125,679	200,419	203,284	426.5	59.24	106.63	0.250	57.91	0.136			9.5
Boiler 1	2	Vibrating Grate	01/07/97	123,272	198,803	210,000	440.8	61.22	110.21	0.250	62.38	0.142			9.5
Boiler 1	3	Vibrating Grate	01/07/97	122,608	200,926	211,765	443.9	61.65	110.97	0.250	56.04	0.126			9.5
Boiler 1	1	Vibrating Grate	01/08/98	148,591	223,239	193,433	404.9	56.24	101.24	0.250	39.25	0.097			9.8
Boiler 1	2	Vibrating Grate	01/08/98	139,359	211,566	209,630	440.0	61.11	103.59	0.240	42.80	0.097			10.8
Boiler 1	3	Vibrating Grate	01/08/98	141,780	215,994	204,507	430.3	59.76	103.60	0.240	54.89	0.128			10.0
Boiler 1	1	Vibrating Grate	12/08/00	116,457	185,495	193,151	406.5	56.46	99.11	0.244	78.60	0.193	67		9.0
Boiler 1	2	Vibrating Grate	12/08/00	117,435	189,657	198,261	419.3	58.23	101.82	0.243	69.20	0.165	62		7.0
Boiler 1	3	Vibrating Grate	12/08/00	114,205	187,798	195,833	414.0	57.50	100.68	0.243	80.96	0.196	65		7.0
Boiler 1	1	Vibrating Grate	12/05/01	122,015	182,934	198,000	403.3	56.01	96.73	0.240	58.44	0.145			8.8
Boiler 1	2	Vibrating Grate	12/05/01	118,508	179,141	201,127	406.5	56.46	96.79	0.238	47.69	0.117			8.0
Boiler 1	3	Vibrating Grate	12/05/01	118,063	177,096	205,588	416.0	57.78	99.18	0.238	51.10	0.123			7.5
Boiler 1	1	Vibrating Grate	11/20/02	139,322	201,193	192,329	386.2	53.64	92.96	0.241	63.82	0.165	91.6		10.5
Boiler 1	2	Vibrating Grate	11/20/02	132,473	194,240	197,391	398.7	55.37	95.88	0.240	81.67	0.205	94		10.2
Boiler 1	3	Vibrating Grate	11/20/02	139,170	200,673	193,333	412.8	57.33	98.68	0.239	70.70	0.171	94.8		10.3
Boiler 1	1	Vibrating Grate	11/14/03	147,286	202,987	196,709	409.0	56.81	102.26	0.250	49.17	0.120	75	56	9.0
Boiler 1	2	Vibrating Grate	11/14/03	152,860	210,916	197,813	414.8	57.61	103.69	0.250	84.77	0.204	75	57	9.0
Boiler 1	3	Vibrating Grate	11/14/03	155,202	215,710	204,000	412.2	57.24	103.04	0.250	83.72	0.203	75	56	9.0
Boiler 1	1	Vibrating Grate	01/13/05	161,467	245,339	197,391	429.2	59.60	107.29	0.250	77.96	0.182	120	370	11.6
Boiler 1	2	Vibrating Grate	01/13/05	164,310	250,264	186,835	402.0	55.83	100.50	0.250	76.50	0.190	120	364	11.5
Boiler 1	3	Vibrating Grate	01/13/05	162,661	244,548	195,652	425.0	59.02	106.24	0.250	81.49	0.192	125	364	11.6

Table B-1. Boiler PM Emission Tests, Clewiston

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
Boiler 2	1	Vibrating Grate	01/22/96	105,831	163,718	177,188	371.7	51.63	92.93	0.250	73.62	0.198			6.0
Boiler 2	2	Vibrating Grate	01/22/96	94,417	150,521	177,188	371.7	51.63	92.93	0.250	66.10	0.178			6.0
Boiler 2	3	Vibrating Grate	01/22/96	93,727	154,170	181,184	379.7	52.74	94.93	0.250	52.37	0.138			6.0
Boiler 2	1	Vibrating Grate	01/12/98	107,485	165,905	172,286	363.3	50.45	90.82	0.250	45.54	0.125			3.0
Boiler 2	2	Vibrating Grate	01/12/98	106,311	165,445	173,824	366.9	50.96	91.72	0.250	48.70	0.133			3.0
Boiler 2	3	Vibrating Grate	01/12/98	104,790	166,166	175,522	370.3	51.43	92.57	0.250	69.51	0.188			
Boiler 2	1	Vibrating Grate	01/13/98	126,475	198,634	201,739	425.1	59.03	101.08	0.240	71.72	0.169			8.5
Boiler 2	2	Vibrating Grate	01/13/98	122,422	195,643	202,059	426.2	59.19	106.55	0.250	71.59	0.168			8.5
Boiler 2	3	Vibrating Grate	01/13/98	125,162	197,964	202,388	427.0	59.31	101.42	0.240	98.31	0.230			8.5
Boiler 2	1	Vibrating Grate	12/12/00	113,638	186,994	169,459	364.4	50.61	87.57	0.240	47.53	0.130	67		8.5
Boiler 2	2	Vibrating Grate	12/12/00	108,878	181,681	174,167	373.3	51.84	88.14	0.236	60.87	0.163	61		8.2
Boiler 2	3	Vibrating Grate	12/12/00	107,998	181,348	163,714	350.3	48.65	81.96	0.234	77.50	0.221	68		8.7
Boiler 2	1	Vibrating Grate	12/12/01	141,555	214,981	212,055	435.1	60.43	103.50	0.238	112.59	0.259			9.3
Boiler 2	2	Vibrating Grate	12/12/01	125,108	187,343	182,535	374.2	51.97	93.55	0.250	73.38	0.196			
Boiler 2	3	Vibrating Grate	12/12/01	127,585	200,931	195,211	403.0	55.97	100.75	0.250	108.53	0.269			
Boiler 2	1	Vibrating Grate	12/17/02	135,626	203,449	173,239	354.6	49.25	88.64	0.250	64.49	0.182	91.8		7.1
Boiler 2	2	Vibrating Grate	12/17/02	133,618	201,955	174,167	356.6	49.53	89.16	0.250	65.36	0.183	90		7.1
Boiler 2	3	Vibrating Grate	12/17/02	134,529	201,199	189,851	389.0	54.03	97.26	0.250	67.82	0.174	80.6		6.3
Boiler 2	1	Vibrating Grate	11/18/03	125,842	196,117	183,478	387.5	53.82	96.88	0.250	88.89	0.229	51.2	75	10.0
Boiler 2	2	Vibrating Grate	11/18/03	132,395	205,353	190,746	405.7	56.35	101.42	0.250	76.69	0.189	50.38	70	9.0
Boiler 2	3	Vibrating Grate	11/18/03	123,840	199,614	192,537	407.4	56.58	101.84	0.250	72.78	0.179	45	65	9.0
Boiler 2	1	Vibrating Grate	11/12/04	153,146	235,990	189,565	399.1	55.43	95.26	0.239	88.69	0.222	123.6	113	9.5
Boiler 2	2	Vibrating Grate	11/12/04	150,689	235,118	198,000	417.9	58.05	102.27	0.245	72.18	0.173	130	123	9.1
Boiler 2	3	Vibrating Grate	11/17/04	174,817	260,767	197,838	424.1	58.91	101.25	0.239	26.34	0.062			

Table B-1. Boiler PM Emission Tests, Clewiston

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)
Boiler 4	1	Traveling Grate	02/23/94	134,590	215,068	283,043	616.9	85.68	92.54	0.150	81.72	0.132	40.5	428	
Boiler 4	2	Traveling Grate	02/23/94	136,057	218,507	290,769	633.1	87.94	94.97	0.150	73.42	0.116	40.6	430	
Boiler 4	3	Traveling Grate	02/23/94	132,839	216,547	284,308	618.0	85.83	92.70	0.150	93.94	0.152	41.2	433	
Boiler 4	1	Traveling Grate	12/30/94	152,950	222,172	288,750	626.8	87.06	94.02	0.150	88.74	0.142	50	492	10.0
Boiler 4	2	Traveling Grate	12/30/94	142,730	220,121	280,986	609.4	84.64	91.41	0.150	70.23	0.115	50	492	10.0
Boiler 4	3	Traveling Grate	12/30/94	144,948	225,530	281,918	614.3	85.32	92.15	0.150	73.08	0.119	50	492	10.0
Boiler 4	1	Traveling Grate	12/22/95	147,476	227,747	290,548	617.5	85.76	92.62	0.150	59.28	0.096	53	300	9.5
Boiler 4	2	Traveling Grate	12/22/95	143,821	222,383	280,946	597.7	83.01	89.65	0.150	63.06	0.106	54	300	9.5
Boiler 4	3	Traveling Grate	12/22/95	145,645	221,056	291,200	617.4	85.75	92.61	0.150	52.29	0.085	55	300	9.5
Boiler 4	1	Traveling Grate	12/17/96	154,554	236,304	289,909	608.8	84.56	91.32	0.150	67.58	0.111	48	245	9.5
Boiler 4	2	Traveling Grate	12/17/96	159,316	241,659	291,818	610.9	84.85	91.64	0.150	70.56	0.116	48	245	9.5
Boiler 4	3	Traveling Grate	12/17/96	156,697	239,434	286,462	601.1	83.49	90.17	0.150	61.82	0.103	48	245	9.5
Boiler 4	1	Traveling Grate	01/05/00	136,759	210,179	238,378	509.0	70.69	73.93	0.145	66.45	0.131		380	8.5
Boiler 4	2	Traveling Grate	01/05/00	136,322	209,218	241,644	514.5	71.46	75.28	0.146	64.16	0.125		390	9.0
Boiler 4	3	Traveling Grate	01/05/00	135,432	208,934	236,800	504.8	70.11	73.99	0.147	55.95	0.111		420	8.5
Boiler 4	1	Traveling Grate	11/17/00	161,372	248,028	258,400	558.2	77.53	83.72	0.150	50.40	0.090	66.4	384	10.2
Boiler 4	2	Traveling Grate	11/17/00	160,074	248,560	256,667	554.7	77.04	83.21	0.150	60.47	0.109	66.4	385	9.6
Boiler 4	3	Traveling Grate	11/17/00	161,936	249,043	262,192	566.9	78.74	85.03	0.150	51.23	0.090			9.3
Boiler 4	1	Traveling Grate	01/23/02	158,108	238,305	255,882	549.8	76.37	82.48	0.150	48.91	0.089	52	477	12.7
Boiler 4	2	Traveling Grate	01/23/02	151,705	231,241	257,647	555.6	77.17	83.34	0.150	32.17	0.058	53	482	10.7
Boiler 4	3	Traveling Grate	01/23/02	155,993	236,906	260,294	561.3	77.96	84.20	0.150	34.81	0.062	67	544	9.5
Boiler 4	1	Traveling Grate	12/18/02	167,367	250,551	272,000	600.4	83.39	90.06	0.150	66.32	0.110	64	533	15.5
Boiler 4	2	Traveling Grate	12/18/02	164,949	247,408	272,000	599.9	83.32	89.98	0.150	57.41	0.096	62.2	534	14.2
Boiler 4	3	Traveling Grate	12/18/02	161,294	241,460	274,783	601.7	83.57	90.26	0.150	54.65	0.091	62.8	537	16.5
Boiler 4	4	Traveling Grate	12/19/02	163,340	245,494	284,250	627.4	87.13					64.5	491	13.2
Boiler 4	1	Traveling Grate	11/21/03	184,631	280,071	265,479	579.9	80.54	86.98	0.150	84.74	0.146	51.02	359	22.5
Boiler 4	2	Traveling Grate	11/21/03	187,732	272,428	264,167	576.9	80.12	86.53	0.150	72.85	0.126	45.84	406	22.4
Boiler 4	3	Traveling Grate	11/21/03	179,768	261,129	260,000	567.1	78.77	85.07	0.150	61.34	0.108	55.38	409	22.4
Boiler 4	1	Traveling Grate	11/24/04	164,581	254,686	267,115	588.5	81.73	88.27	0.150	71.68	0.122	72.86	493	11.0
Boiler 4	2	Traveling Grate	11/24/04	165,619	262,011	259,737	572.2	79.47	85.83	0.150	74.10	0.130	71.67	492	11.0
Boiler 4	3	Traveling Grate	11/24/04	165,111	263,455	246,923	542.8	75.39	81.42	0.150	79.60	0.147	72.4	490	11.0
Boiler 4	4	Traveling Grate	11/24/04	166,378	265,717	254,526	558.2	77.53	83.73	0.150	74.71	0.134	70.67	419	11.0
Boiler 4	1	Traveling Grate	02/10/05	156,977	228,241	237,600	515.1	71.54	77.26	0.150	58.57	0.114	78.6	611	11.0
Boiler 4	2	Traveling Grate	02/10/05	158,258	233,152	239,178	516.5	71.73	77.47	0.150	59.15	0.115	80.2	623	10.9
Boiler 4	3	Traveling Grate	02/10/05	161,994	235,662	230,649	500.5	69.52	75.08	0.150	53.51	0.107	78.6	623	11.0

Table B-1. Boiler PM Emission Tests, Clewiston

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5) lb/hr	Allowable PM Emissions (EPA Method 5) lb/MMBtu	Actual PM Emissions (EPA Method 5) lb/hr	Actual PM Emissions (EPA Method 5) lb/MMBtu	Total Power Input (kW)
Boiler 7	1	Spreader-Stoker Vibrating Grate	02/04/05	165,392	296,331	232,174	494.28	68.65	14.83	0.030	11.57	0.023	49.32
Boiler 7	2	Spreader-Stoker Vibrating Grate	02/04/05	161,579	296,174	228,000	487.84	67.76	14.64	0.030	6.84	0.014	55.14
Boiler 7	3	Spreader-Stoker Vibrating Grate	02/04/05	159,426	285,860	223,099	475.52	66.04	14.27	0.030	13.03	0.027	70.01

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.

Footnotes:

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

Table B-2. Boiler PM Emission Tests, Bryant

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate	Stack Gas Flow Rate	Steam Rate	Heat Input Rate	Bagasse Burning Rate[1]	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure	Avg. Water Flow	Avg. Pressure Drop
				(dscfm)	(acfm)	(lb/hr)	(MMBtu/hr)	(TPH)	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	(psig)	(gpm)	(in. H_2O)
Boiler 1	1	Vibrating Grate	12/06/95	86,294	139,819	181,500	343.1	47.65	102.92	0.300	29.39	0.086	37	246	6.4
Boiler 1	2	Vibrating Grate	12/06/95	79,708	116,374	176,962	333.9	46.38	100.18	0.300	30.48	0.091	44.0	220	6.0
Boiler 1	3	Vibrating Grate	12/06/95	92,589	137,658	178,421	335.8	46.64	100.75	0.300	39.05	0.116	45	225	6.2
Boiler 1	1	Vibrating Grate	11/20/00	88,333	139,209	151,965	293.3	40.74	87.99	0.300	38.85	0.132		299	9.0
Boiler 1	2	Vibrating Grate	11/20/00	88,077	136,966	148,445	287.7	39.95	86.29	0.300	40.40	0.140		300	9.0
Boiler 1	3	Vibrating Grate	11/20/00	89,206	139,900	144,789	280.2	38.92	84.07	0.300	38.43	0.137		303	9.0
Boiler 1	1	Vibrating Grate	11/27/01	90,185	146,160	156,675	304.4	42.28	91.31	0.300	69.98	0.230	57	277	9.5
Boiler 1	2	Vibrating Grate	11/27/01	92,735	159,796	155,634	304.0	42.23	91.21	0.300	16.46	0.054	57	275	9.3
Boiler 1	3	Vibrating Grate	11/27/01	90,224	152,446	162,750	319.1	44.32	95.73	0.300	23.11	0.072	57	275	9.3
Boiler 1	1	Vibrating Grate	11/27/02	88,588	142,319	155,926	299.0	41.52	89.69	0.300	38.78	0.130	55.3	240	9.0
Boiler 1	2	Vibrating Grate	11/27/02	85,497	143,200	163,425	314.1	43.63	94.23	0.300	16.38	0.052	55.5	240	9.0
Boiler 1	3	Vibrating Grate	11/27/02	87,341	141,308	158,308	304.5	42.30	91.36	0.300	23.38	0.077	55	240	9.0
Boiler 1	1	Vibrating Grate	12/05/03	68,695	114,572	158,518	303.0	42.09	90.91	0.300	35.15	0.116	60	240	9
Boiler 1	2	Vibrating Grate	12/05/03	83,983	127,692	160,887	303.9	42.20	91.16	0.300	29.90	0.098	60	240	9
Boiler 1	3	Vibrating Grate	12/05/03	95,884	149,510	162,301	309.0	42.92	92.71	0.300	43.62	0.141	59.7	240	9
Boiler 1	1	Vibrating Grate	12/03/04	77,079	123,377	159,730	303.2	42.11	90.96	0.300	32.84	0.108		240	8.0
Boiler 1	2	Vibrating Grate	12/03/04	77,794	127,123	162,969	310.2	43.08	93.05	0.300	27.97	0.090		240	8.0
Boiler 1	3	Vibrating Grate	12/03/04	82,959	131,088	162,433	307.6	42.73	92.29	0.300	37.32	0.121		240	8.0

Table B-2. Boiler PM Emission Tests, Bryant

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate	Stack Gas Flow Rate	Steam Rate	Heat Input Rate	Bagasse Burning Rate [1]	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure	Avg. Water Flow	Avg. Pressure Drop (in. H_2O)	
				(dscfm)	(acfm)	(lb/hr)	(MMBtu/hr)	(TPH)	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	(psig)	(gpm)	North	South
Boiler 2	1	Vibrating Grate	12/07/95	82,812	123,640	160,741	301.0	41.80	90.29	0.300	68.31	0.227	50	225	7.0	6.0
Boiler 2	2	Vibrating Grate	12/07/95	78,950	116,459	165,385	310.0	43.05	92.99	0.300	52.70	0.170	51.7	229	7.0	6.0
Boiler 2	3	Vibrating Grate	12/07/95	69,899	103,638	167,368	314.0	43.61	94.20	0.300	45.61	0.145	49	233	7.0	7.0
Boiler 2	1	Vibrating Grate	11/29/00	90,012	135,845	161,786	310.8	43.17	93.25	0.300	35.78	0.118	60	359	3.9	4.7
Boiler 2	2	Vibrating Grate	11/29/00	86,272	134,092	152,734	297.8	41.36	89.34	0.300	40.93	0.137	60	358	4.1	5.0
Boiler 2	3	Vibrating Grate	11/29/00	90,062	135,845	153,740	302.0	41.94	90.60	0.300	35.78	0.118	60.7	360	4.5	5.1
Boiler 2	1	Vibrating Grate	11/26/01	85,353	134,931	158,835	307.3	42.68	92.20	0.300	32.68	0.106	62	355	4.5	
Boiler 2	2	Vibrating Grate	11/26/01	79,486	128,541	158,096	308.1	42.79	92.43	0.300	31.37	0.102	62	355	5.0	
Boiler 2	3	Vibrating Grate	11/26/01	84,295	129,729	161,926	313.5	43.54	94.04	0.300	21.38	0.068	62	355	5.0	
Boiler 2	1	Vibrating Grate	11/26/02	98,154	149,921	158,864	307.7	42.74	92.31	0.300	40.06	0.130	59.3	352	4.5	4.3
Boiler 2	2	Vibrating Grate	11/26/02	91,488	147,528	161,561	311.8	43.31	93.54	0.300	31.74	0.102	59.2	353	4.3	4.3
Boiler 2	3	Vibrating Grate	11/26/02	92,399	147,765	172,208	333.2	46.28	99.96	0.300	48.13	0.144	58	360	4.3	4.3
Boiler 2	1	Vibrating Grate	12/04/03	84,651	127,322	145,626	286.6	39.80	85.97	0.300	22.35	0.078	60	360	4.2	4.0
Boiler 2	2	Vibrating Grate	12/04/03	86,574	133,711	146,100	287.4	39.92	86.22	0.300	36.53	0.127	60	360	4.0	4.0
Boiler 2	3	Vibrating Grate	12/04/03	96,457	143,427	148,679	291.4	40.48	87.43	0.300	21.97	0.075	60	360	4.2	4.0
Boiler 2	4	Vibrating Grate	12/04/03	83,436	129,793	146,542	287.6	39.95	86.29	0.300	35.79	0.124	60	360	4.3	4.1
Boiler 2	1	Vibrating Grate	12/02/04	84,055	137,921	159,488	307.1	42.65	92.12	0.300	37.17	0.121		350	4.0	4.0
Boiler 2	2	Vibrating Grate	12/02/04	79,419	131,984	157,147	302.6	42.03	90.79	0.300	38.65	0.128		360	4.0	4.0
Boiler 2	3	Vibrating Grate	12/02/04	87,454	143,563	160,603	308.9	42.90	92.66	0.300	33.07	0.107		360	4.0	4.0

Table B-2. Boiler PM Emission Tests, Bryant

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate	Stack Gas Flow Rate	Steam Rate	Heat Input Rate	Bagasse Burning Rate [1]	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure	Avg. Water Flow	Avg. Pressure Drop
				(dscfm)	(acfm)	(lb/hr)	(MMBtu/hr)	(TPH)	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	(psig)	(gpm)	(in. H_2O)
Boiler 3	1	Vibrating Grate	12/08/95	77,426	118,767	153,253	288.2	40.03	86.46	0.300	78.07	0.271	50	272	8.0
Boiler 3	2	Vibrating Grate	12/08/95	84,155	131,470	146,250	275.5	38.27	82.66	0.300	76.20	0.277	50	258	7.6
Boiler 3	3	Vibrating Grate	12/08/95	69,082	108,458	144,935	285.2	39.61	85.65	0.300	61.93	0.217	50	270	7.2
Boiler 3	1	Vibrating Grate	12/18/96	89,926	145,809	166,216	324.5	45.07	97.35	0.300	43.78	0.135	51	337	7.8
Boiler 3	2	Vibrating Grate	12/18/96	85,316	140,249	162,532	317.2	44.06	95.15	0.300	49.38	0.116	50.4	341	6.5
Boiler 3	3	Vibrating Grate	12/18/96	85,345	138,525	162,857	320.6	44.53	96.17	0.300	47.89	0.149	57	331	7.8
Boiler 3	1	Vibrating Grate	11/30/00	86,941		160,554	312.8	43.45	93.85	0.300	25.02	0.080	61	280	7.9
Boiler 3	2	Vibrating Grate	11/30/00	90,342		163,737	318.9	44.30	95.68	0.300	31.05	0.097	61	280	8.0
Boiler 3	3	Vibrating Grate	11/30/00	84,253		163,063	317.4	44.08	95.21	0.300	32.37	0.102	61	280	7.9
Boiler 3	1	Vibrating Grate	11/25/02	90,213		159,063	304.7	42.32	91.40	0.300	30.69	0.101	62	247	8.0
Boiler 3	2	Vibrating Grate	11/25/02	88,750		156,141	303.7	42.19	91.12	0.300	21.90	0.072	62	250	8.0
Boiler 3	3	Vibrating Grate	11/25/02	89,057		160,265	310.9	43.18	93.26	0.300	41.47	0.133	62	244	8.0
Boiler 3	1	Vibrating Grate	12/03/03	81,606		155,236	305.1	42.37	91.52	0.300	39.59	0.130	48.2	242	7.0
Boiler 3	2	Vibrating Grate	12/03/03	88,011		159,924	313.2	43.50	93.96	0.300	36.84	0.118	58	244	7.0
Boiler 3	3	Vibrating Grate	12/03/03	90,473		162,898	318.5	44.24	95.56	0.300	46.50	0.146	60	244	7.0
Boiler 3	1	Vibrating Grate	12/01/04	69,859	117,289	160,926	310.1	43.07	93.03	0.300	42.91	0.138		240	8.0
Boiler 3	2	Vibrating Grate	12/01/04	69,489	118,247	165,646	318.4	44.22	95.52	0.300	32.60	0.102		240	8.0
Boiler 3	3	Vibrating Grate	12/01/04	76,903	130,031	161,835	311.4	43.25	93.42	0.300	43.43	0.139		240	8.0

Table B-2. Boiler PM Emission Tests, Bryant

Unit	Run Number	Boiler Type	Test Date	Stack Gas Flow Rate (dscfm)	Stack Gas Flow Rate (acfm)	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate [1] (TPH)	Allowable PM Emissions (EPA Method 5)		Actual PM Emissions (EPA Method 5)		Avg. Liquid Pressure (psig)	Avg. Water Flow (gpm)	Avg. Pressure Drop (in. H_2O)	
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			North	South
Boiler 5	1	Vibrating Grate	02/11/94	139,793	194,449	230,704	508.8	70.67	152.65	0.300	38.27	0.075	46	880	10.0	10.0
Boiler 5	2	Vibrating Grate	02/11/94	136,855	194,010	233,333	516.1	71.68	154.84	0.300	33.37	0.065	48	880	10.0	10.0
Boiler 5	3	Vibrating Grate	02/11/94	136,741	193,190	243,000	535.9	74.43	160.78	0.300	42.88	0.080	47	860	10.0	10.0
Boiler 5	1	Vibrating Grate	12/12/94	145,611	205,105	234,348	522.2	72.52	156.65	0.300	35.35	0.068	54.4	904	11.7	11.2
Boiler 5	2	Vibrating Grate	12/12/94	143,214	202,908	233,333	519.5	72.15	155.84	0.300	43.35	0.038	50	900	11.8	11.2
Boiler 5	3	Vibrating Grate	12/12/94	141,383	200,224	243,600	544.3	75.59	163.28	0.300	68.10	0.125	50.2	888	11.7	11.4
Boiler 5	1	Vibrating Grate	01/12/96	143,543	194,905	243,529	547.4	76.03	164.23	0.300	36.65	0.067	53.2	966	11.8	12.0
Boiler 5	2	Vibrating Grate	01/12/96	144,597	199,699	245,294	552.1	76.67	165.62	0.300	16.32	0.030	53.6	960	11.9	11.8
Boiler 5	3	Vibrating Grate	01/12/96	142,265	197,455	240,000	540.6	75.08	162.17	0.300	58.98	0.109	54	960	12.0	11.8
Boiler 5	1	Vibrating Grate	12/23/97	144,605	196,594	250,154	558.1	77.51	167.42	0.300	62.03	0.111	55	886	12.0	11.3
Boiler 5	2	Vibrating Grate	12/23/97	139,553	195,575	247,500	552.5	76.73	165.74	0.300	79.56	0.144	59.6	923	12.1	11.5
Boiler 5	3	Vibrating Grate	12/23/97	142,170	197,815	248,060	554.5	77.01	166.34	0.300	82.58	0.149	56.3	919	12.0	11.6
Boiler 5	1	Vibrating Grate	11/28/00	146,321		221,486	491.7	68.29	147.52	0.300	68.54	0.139	63	900	12.3	12.5
Boiler 5	2	Vibrating Grate	11/28/00	143,043		218,912	486.3	67.55	145.90	0.300	55.67	0.114	62	900	12.9	12.9
Boiler 5	3	Vibrating Grate	11/28/00	149,281		220,225	491.3	68.23	147.38	0.300	71.35	0.145	61.8	900	13.5	13.5
Boiler 5	1	Vibrating Grate	11/30/01	138,158		228,882	489.0	67.92	146.70	0.300	39.67	0.080	56	900	11.5	11.5
Boiler 5	2	Vibrating Grate	11/30/01	139,931		221,206	486.5	67.57	145.96	0.300	55.05	0.113	56	900	11.5	11.5
Boiler 5	3	Vibrating Grate	11/30/01	144,314		230,833	502.6	69.80	150.78	0.300	39.25	0.078	56	900	11.5	11.5
Boiler 5	1	Vibrating Grate	12/04/02	157,781		230,783	497.6	69.12	149.29	0.300	19.67	0.040	52	900	7.6	7.5
Boiler 5	2	Vibrating Grate	12/04/02	157,883		225,042	493.0	68.48	147.91	0.300	32.65	0.066	52	900	7.6	7.6
Boiler 5	3	Vibrating Grate	12/04/02	163,176		219,583	481.9	66.93	144.57	0.300	33.32	0.069	53.2	900	7.6	7.6
Boiler 5	1	Vibrating Grate	12/10/03	172,017		202,342	444.3	61.71	133.30	0.300	65.06	0.146	60	900	12.1	12.8
Boiler 5	2	Vibrating Grate	12/10/03	184,291		205,117	451.5	62.70	135.44	0.300	54.68	0.121	59.8	900	12.0	12.2
Boiler 5	3	Vibrating Grate	12/10/03	187,191		203,827	447.1	62.10	134.13	0.300	61.03	0.136	60	900	12.0	12.3
Boiler 5	1	Vibrating Grate	12/08/04	154,671	217,383	240,806	519.7	72.18	155.91	0.300	33.80	0.065		850	11.5	11.0
Boiler 5	2	Vibrating Grate	12/08/04	145,488	208,437	229,127	494.5	68.69	148.36	0.300	46.35	0.094		850	11.5	11.0
Boiler 5	3	Vibrating Grate	12/08/04	152,109	212,927	236,835	513.0	71.26	153.91	0.300	42.14	0.082		850	11.5	11.0

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.

Footnote:

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