DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Jonathan Holtom, ARM
2. MAIL STATION #5500-MAGNOLIA CENTER
3. ________
4. ________
5. ________

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE: ____

ACTION/DISPOSITION:

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

√ FOR YOUR FILES

COMMENTS:

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JUL 29 2005
BUREAU OF AIR REGULATION

FROM: Mara Nasca / South District DATE: 07/27/2005 PHONE: SC 748-6975

DEP 15-026 (12/93)

Atlantic Sugar 0990016 – CAM Plan, submitted 07-08-05
Preliminary Review- 07-25-05 MGN

Emission Unit-Pollutant	Control Device	Design-Pressure Drop	Requested Excursion	Design-H_2O inlet Pressure	Design H_2O Flow	Requested Excursion	Comments
Boiler No.1-PM	Joy type Impingement Scrubber	4-7"	3.7"	70-80 psig	300-400 gpm	306 gpm	Increase in pressure drop? Inlet and outlet ducts? Unit calibrated, maintained and operated Test data lows= 4.15 and 340
Boiler No.2 – PM	Joy type Impingement Scrubber	4-6"	Below 4"	60-80 psig	300-500 gpm	338 gpm	Test data lows= 4.31 and 345
Boiler No.3 – PM	Joy type Impingement Scrubber	4-6"	3.3"	60-80 psig	300-400 gpm	310 gpm	Test data lows= 3.62 and 345
Boiler No.4 – PM	Joy type Impingement Scrubber	4-7"	3.8"	50-80 psig	300-400 gpm	310 gpm	Test data lows= 4.20 and 345
Boiler No.5 – PM	Type D Joy Turbulaire	7-11"	7.4"	60-80 psig	900-2000 gpm	225 gpm (828)	Test data lows= 2.82 and 920 No pressure drop vs steam rate graph

- Where is the 8-hour data for total pressure drop and scrubber water inlet pressure, a current requirement?
- Boiler 5 pressure drop vs steam rate missing?

COMPLIANCE ASSURANCE MONITORING PLAN
(CAM PLAN)

for

Atlantic Sugar Association

Belle Glade, FL

July 2005

0437646

RECEIVED
JUL 0 8 2005
D.E.P. - South Distric

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1.0 EMISSION UNITS REQUIRING CAM PLANS

1.1 CAM RULE APPLICABILITY DEFINITION

On May 8, 2003, the Florida Department of Environmental Protection (FDEP) issued a Title V Air Operation Revision (Permit No. 0990016-006-AV) to Atlantic Sugar Association, Inc. for operation of its Belle Glade, FL sugar mill boilers. This permit expires on December 18, 2005. In order to renew the permit, a renewal application must be submitted to the Florida Department of Environmental Protection (FDEP). The renewal application is due to FDEP by June 21, 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 as 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 from 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 EMISSIONS UNITS REQUIRING CAM PLANS

A review of emissions units at the Atlantic Sugar Association sugar mill 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 calculated 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. Each pollutant-specific emissions unit at the Atlantic Sugar Association sugar mill, and its applicability to CAM, is described in the following sections.

1.2.1 BOILER NO. 1 (EU 001)

Boiler No. 1 is a dumping grate boiler fired with carbonaceous fuel (bagasse, wood chips, rice hulls) and supplemented with No. 6 residual fuel oil. Boiler No. 1 has a maximum capacity of 144,000 pounds per hour (lb/hr) steam. This corresponds to a maximum heat input rate of 280 million British thermal units per hour (MMBtu/hr) (24-hour average). The boiler can fire No. 6 fuel oil as a supplemental fuel at a maximum heat input rate of 37.8 MMBtu/hr.

Boiler No. 1 has federally enforceable emission limits for particulate matter (PM), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Boiler No. 1 utilizes a Joy type

Impingement Scrubber (equivalent to Type D) to control PM emissions. As shown in Table 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 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 NO_x, SO_2, and VOC are not required.

1.2.2 BOILER NO. 2 (EU 002)

Boiler No. 2 is a dumping grate boiler fired with carbonaceous fuel (bagasse, wood chips, rice hulls) and supplemented with No. 6 residual fuel oil. Boiler No. 2 has a maximum capacity of 144,000 lb/hr steam and a maximum heat input rate of 280 MMBtu/hr (24-hour average). The boiler can fire No. 6 fuel oil as a supplemental fuel at a maximum heat input rate of 37.8 MMBtu/hr.

Boiler No. 2 has federally enforceable emission limits for PM, NO_x, SO_2, and VOC. Boiler No. 2 utilizes a Joy type Impingement Scrubber (equivalent to Type D) to control PM emissions. As shown in Table 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 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 NO_x, SO_2, and VOC are not required.

1.2.3 BOILER NO. 3 (EU 003)

Boiler No. 3 is cell type boiler fired with carbonaceous fuel (bagasse, wood chips, rice hulls) and supplemented with No. 6 residual fuel oil. Boiler No. 3 has a maximum capacity of 130,000 lb/hr steam. This corresponds to a maximum heat input rate of 260 MMBtu/hr (24-hour average). The boiler can fire No. 6 fuel oil as a supplemental fuel at a maximum heat input rate of 37.8 MMBtu/hr.

Boiler No. 3 has federally enforceable emission limits for PM, NO_x, SO_2, and VOC. Boiler No. 3 utilizes a Joy type Impingement Scrubber (equivalent to Type D, size 90) to control PM emissions. As shown in Table 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 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 NO_x, SO_2, and VOC are not required.

1.2.4 BOILER NO. 4 (EU 004)

Boiler No. 4 is a cell type boiler fired with carbonaceous fuel (bagasse, wood chips, rice hulls) and supplemented with No. 6 residual fuel oil. Boiler No. 4 has a maximum capacity of 137,000 lb/hr steam. This corresponds to a maximum heat input rate of 254 MMBtu/hr (24-hour average). The boiler can also fire No. 6 fuel oil as a supplemental fuel at a maximum heat input rate of 37.8 MMBtu/hr.

Boiler No. 4 has federally enforceable emission limits for PM, NO_x, SO_2, and VOC. Boiler No. 4 utilizes a Joy type Impingement Scrubber (equivalent to Type D) to control PM emissions. As shown in Table 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 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, or VOC emissions from Boiler No. 4, CAM plans for NO_x, SO_2, and VOC are not required.

1.2.5 BOILER NO. 5 (EU 005)

Boiler No. 5 is a traveling grate boiler (including economizer) fired by bagasse as the primary fuel and No. 6 fuel oil, wood chips, and rice hulls as supplemental fuels. Boiler No. 5 has a maximum capacity of 130,000 lb/hr, corresponding to a maximum heat input rate of 255.3 MMBtu/hr (1-hour average). The boiler has two fuel oil burners, and can fire No. 6 fuel oil as a supplemental fuel at a maximum heat input rate of 70.5 MMBtu/hr (1-hour average).

Boiler No. 5 has federally enforceable emission limits for PM/PM_{10}, NO_x, SO_2, VOC, and CO. Boiler No. 5 utilizes a Type D Joy Turbulaire wet impingement scrubber to control PM emissions. As shown in Table 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 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, SO_2, VOC, or CO emissions from Boiler No. 5, CAM plans for NO_x, SO_2, VOC, and CO are not required.

Table 1. CAM Applicability Determination for Atlantic Sugar Association

Emission Source	Title V EU ID	Control Equipment	Pollutants with Emission Limits	Uncontrolled Emission Rate (TPY)	CAM Plan Required? (Yes/No)	Comments
Boiler No. 1	001	Wet Scrubber	PM	>100 TPY	**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 TPY	**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 TPY	**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. 4	004	Wet Scrubber	PM	>100 TPY	**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 TPY	**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.

2.0 PARTICULATE MATTER EMISSIONS FROM BOILER NO. 1

2.1 EMISSIONS UNIT IDENTIFICATION

Boiler No. 1—EU ID 001

2.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 1 has a PM emission limit of 0.30 lb/MMBtu for carbonaceous fuel, plus 0.10 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C.]. The equivalent potential emissions are 84.0 lb/hr and 183.5 TPY for carbonaceous fuel and 3.8 lb/hr and 8.3 TPY for No. 6 fuel oil. The current visible emissions (VE) limit is 30-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour. Visible emission limits shall be effective only if the visible emission measurement can be made without being substantially affected by plume mixing or moisture condensation (Permit No. 0990016-006-AV).

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. 0990016-006-AV).

2.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 1 are controlled by a Joy type Impingement Scrubber (equivalent to Type D). The scrubber exhausts through a 90-foot stack.

The design pressure drop across the scrubber is 4 to 7 inches of water (in. H_2O). The design water inlet pressure to the scrubber is 70 to 80 pounds per square inch gauge (psig). The design water flow rate to the scrubber is 300 to 400 gallons per minute (gpm). The effectiveness of the wet scrubber is evaluated with an annual stack test and visible emissions measurement. A detailed description of the control equipment is included in the Title V renewal application (Attachment ASA-EU1-I3).

2.4 MONITORING APPROACH

The monitoring approach is based on monitoring total 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	Total pressure drop across the scrubber.	Total water flow rate through the scrubber.
Measurement Approach	Pressure drop is measured with a pressure transducer.	The scrubber water flow rate is measured using an orifice meter.
Indicator Range	An excursion is defined as any individual pressure drop below 3.7 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any individual water flow rate below 306 gallons per minute (gpm). Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a pressure transducer, which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.01 inches of water gauge pressure.	The scrubber water orifice meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5%.
Verification of Operational Status	Readout in boiler control room.	Readout in boiler control room.
QA/QC Practices and Criteria	The pressure transducer is maintained in accordance with the manufacturer's recommendations.	The orifice 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 eight (8) hours. 15 min, to create 1 hr Avge	Reading taken once every eight (8) hours. 15 min
Averaging Period	NA 1 hr	NA

2.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate through 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.

Scrubber inlet water supply pressure is currently monitored for Boiler No. 1, 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.

Atlantic 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 are presented in Figure 2-1 and Figure 2-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values from the test runs, using the historic test data. The calculation of the minimum parameter values are provided below:

Pressure Drop: Minimum test run value = 4.15 in. H_2O

Minimum parameter value = 4.15 x 0.9 = 3.7 in. H_2O

Water Flow Rate: Minimum test run value = 340 gpm

Minimum parameter value = 340 x 0.9 = 306 gpm

Wet scrubber operating parameter values below these minimum parameter values would be 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 maximum achievable control technology (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 63.3(b)(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.

ASA has been recording scrubber parameters once per 8-hour shift, according to the current Title V permit conditions. Although ASA has continuous pressure drop and water flow rate monitors in

Water Level in Scrubber [illegible]

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 would 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.

Figure 2-1. ASA Boiler No. 1
PM vs. Pressure Drop

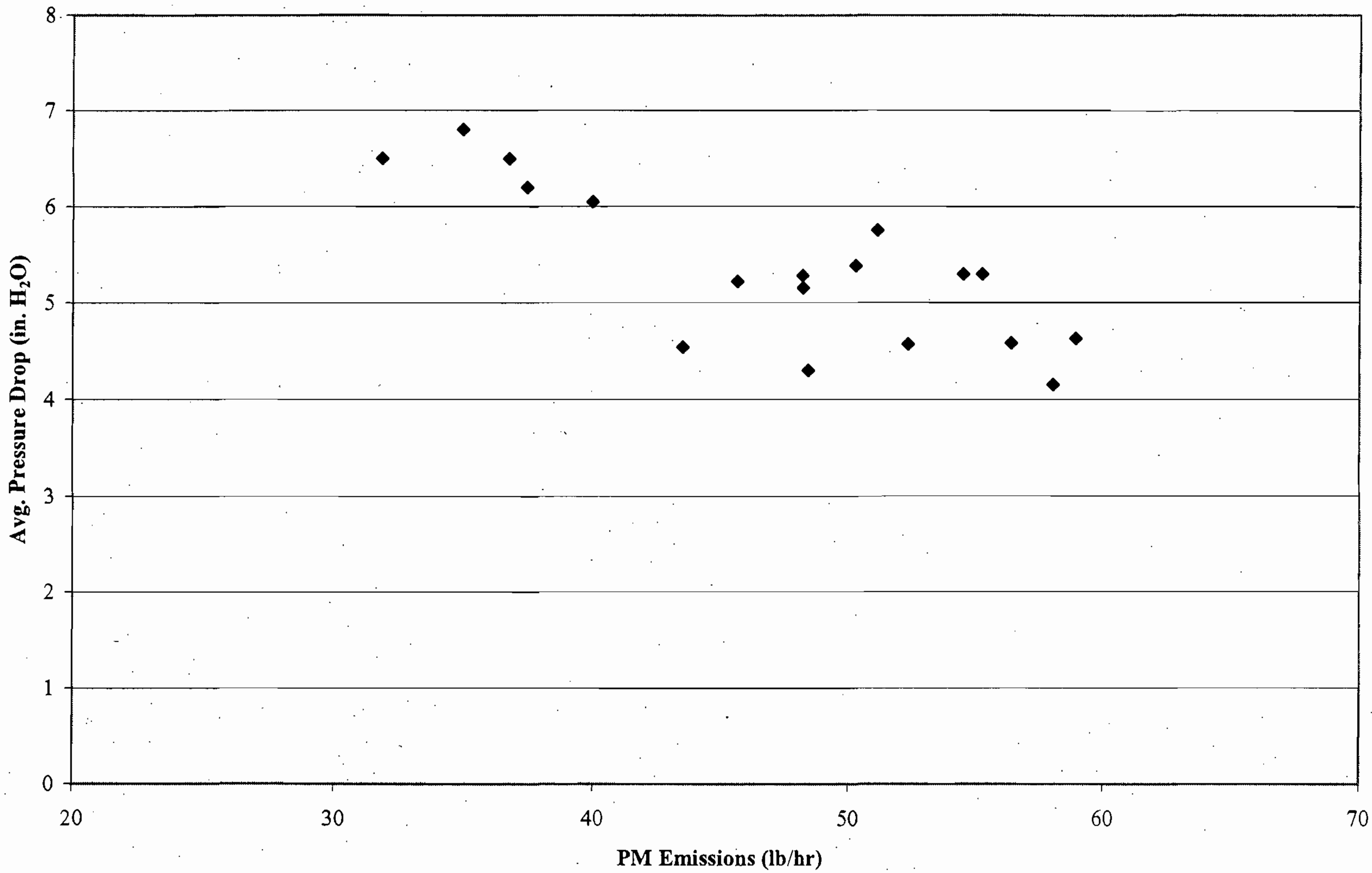
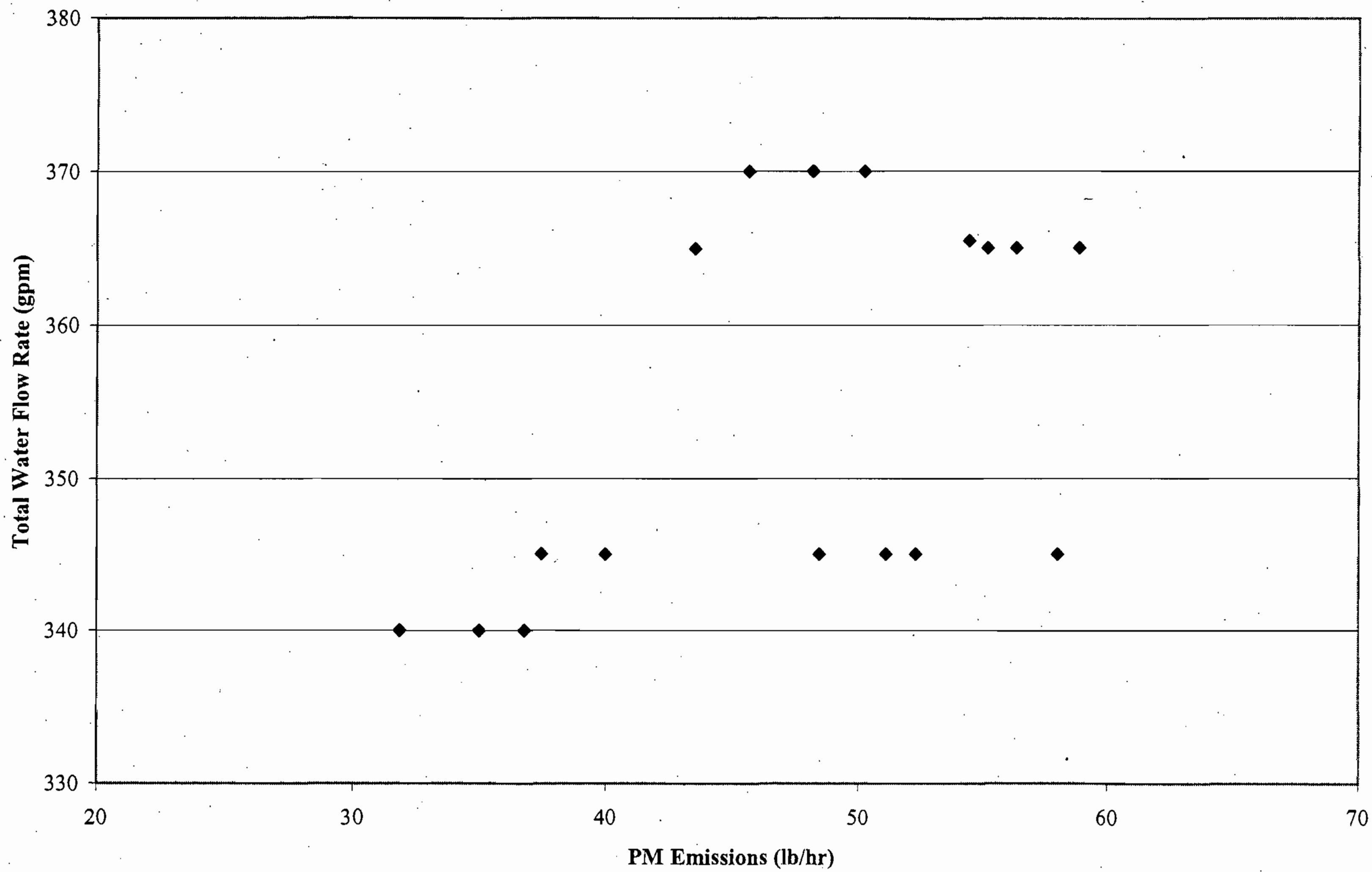


Figure 2-2. ASA Boiler No. 1
PM vs. Total Water Flow Rate



3.0 PARTICULATE MATTER EMISSIONS FROM BOILER NO. 2

3.1 EMISSIONS UNIT IDENTIFICATION

Boiler No. 2—EU ID 002

3.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 2 has a PM emission limit of 0.30 lb/MMBtu for carbonaceous fuel, plus 0.10 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C.]. The equivalent potential emissions are 84.0 lb/hr and 183.5 TPY for carbonaceous fuel and 3.8 lb/hr and 8.3 TPY for No. 6 fuel oil. The current visible emissions (VE) limit is 30-percent opacity, with an exception of up to 40-percent opacity for 2 minutes per hour. Visible emission limits shall be effective only if the visible emission measurement can be made without being substantially affected by plume mixing or moisture condensation (Permit No. 0990016-006-AV).

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. 0990016-006-AV).

3.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 2 are controlled by a Joy type Impingement Scrubber (equivalent to Type D). The scrubber exhausts through a 90-foot stack.

The design pressure drop across the scrubber is 4 to 6 in. H_2O. The design scrubber water inlet pressure to the scrubber is 60 to 80 psig. The design water flow rate to the scrubber is 300 to 500 gpm. The effectiveness of the wet scrubber is evaluated with an annual stack test and visible emissions measurement. A detailed description of the control equipment is included in the Title V renewal application (Attachment ASA-EU2-I3).

3.4 MONITORING APPROACH

The monitoring approach is based on monitoring total 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	Total pressure drop across the scrubber.	Total water flow rate through the scrubber.
Measurement Approach	Pressure drop is measured with a pressure transducer.	The scrubber water flow rate is measured using an orifice meter.
Indicator Range	An excursion is defined as any individual pressure drop below 4.0 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any individual water flow rate below 338 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a pressure transducer, which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.01 inches of water gauge pressure.	The scrubber water orifice meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5%.
Verification of Operational Status	Readout in boiler control room.	Readout in boiler control room.
QA/QC Practices and Criteria	The pressure transducer is maintained in accordance with the manufacturer's recommendations.	The orifice 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 eight (8) hours.	Reading taken once every eight (8) hours.
Averaging Period	NA	NA

3.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate through 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.

Scrubber inlet water supply pressure is currently monitored for Boiler No. 2, 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.

Atlantic 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 are presented in Figure 3-1 and Figure 3-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values from the 1-hour test runs, using the historic test data. The calculation of the minimum parameter values are provided below:

Pressure Drop: Minimum test run value = 4.44 in. H_2O

Minimum parameter value = 4.44 x 0.9 = 4.0 in. H_2O

Water Flow Rate: Minimum test run value = 375 gpm

Minimum parameter value = 375 x 0.9 = 338 gpm

Wet scrubber operating parameter values below these minimum parameter values would be 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 maximum achievable control technology (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 (4) times per hour. However, 40 CFR 63.3(b)(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.

ASA has been recording scrubber parameters once per 8-hour shift, according to the current Title V permit conditions. Although ASA 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 would 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.

Figure 3-1. ASA Boiler No. 2
PM vs. Pressure Drop

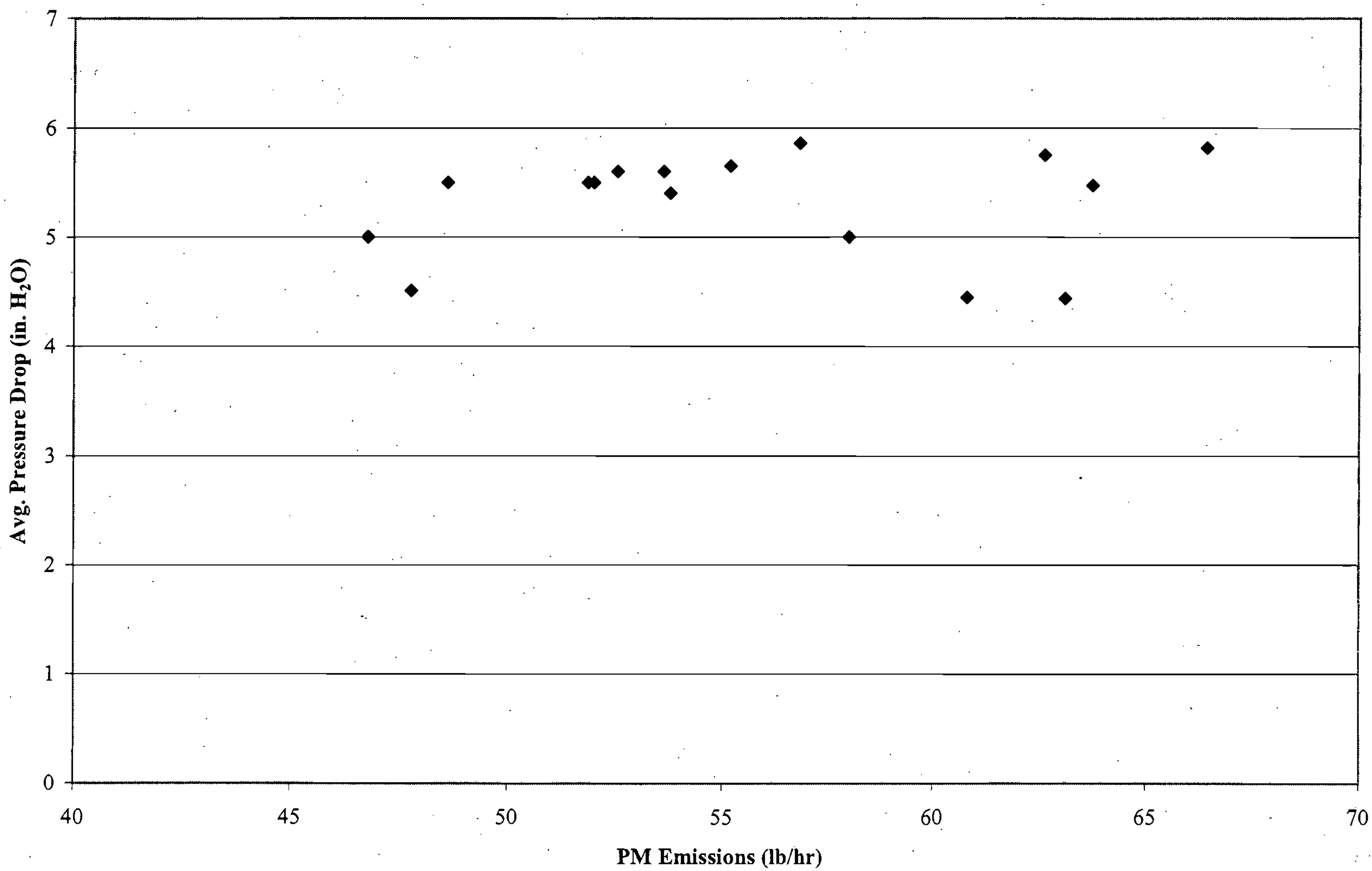
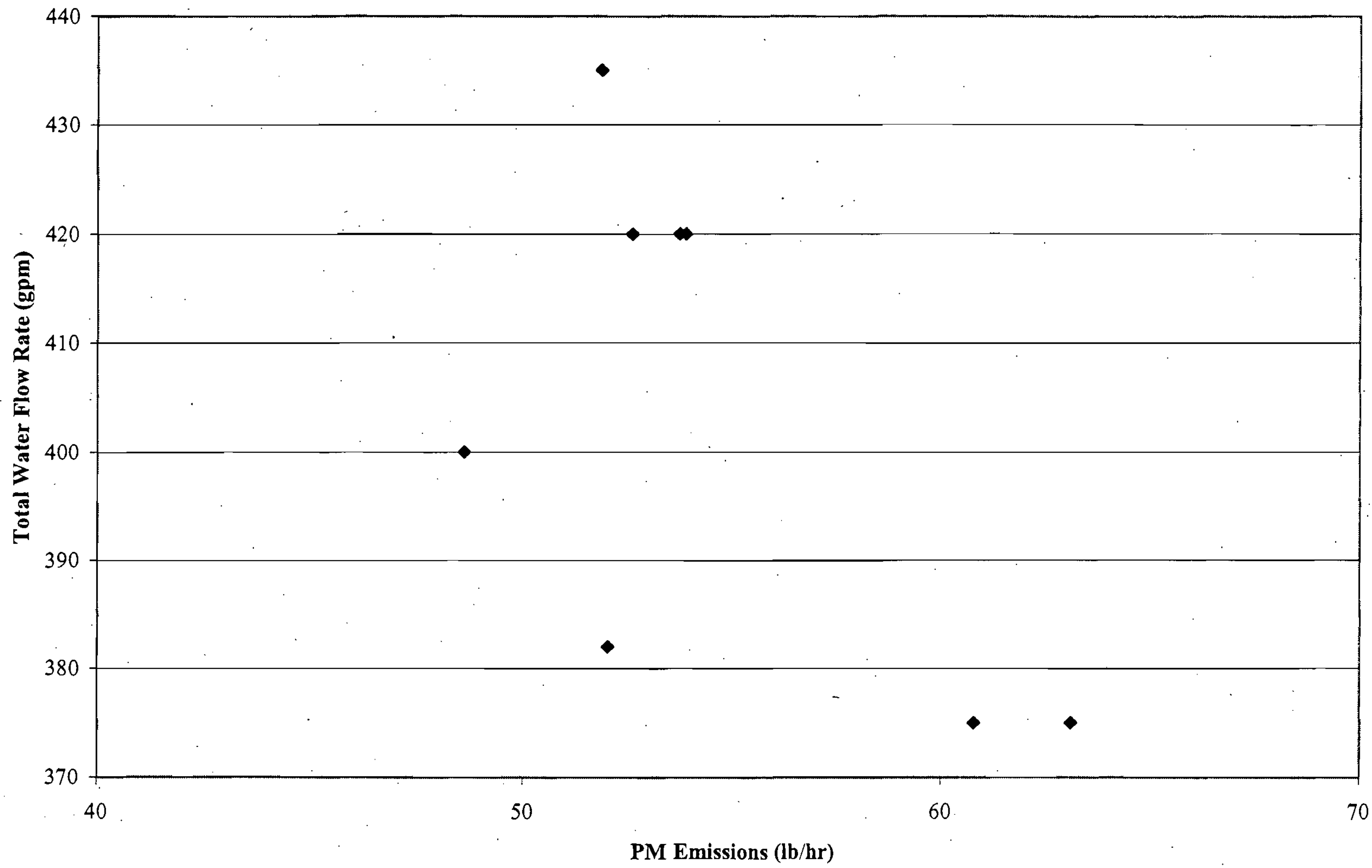


Figure 3-2. ASA Boiler No. 2
PM vs. Total Water Flow Rate



4.0 PARTICULATE MATTER EMISSIONS FROM BOILER NO. 3

4.1 EMISSIONS UNIT IDENTIFICATION

Boiler No. 3—EU ID 003

4.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 3 has a PM emission limit of 0.30 lb/MMBtu for carbonaceous fuel, plus 0.10 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C.]. The equivalent potential emissions are 78.0 lb/hr and 170.4 TPY for carbonaceous fuel and 3.8 lb/hr and 8.3 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. Visible emission limits shall be effective only if the visible emission measurement can be made without being substantially affected by plume mixing or moisture condensation (Permit No. 0990016-006-AV).

PM and VE compliance testing is required annually on Boiler No. 3. In addition, the total pressure drop across each 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. 0990016-006-AV).

4.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 3 are controlled by a Joy type Impingement Scrubber (equivalent to Type D, size 90). The scrubber exhausts through a 90-foot stack.

The design pressure drop across the scrubber is 4 to 6 in. H_2O. The design water inlet pressure to the scrubber is 60 to 80 psig. The design water flow rate to the scrubber is 300 to 400 gpm. The effectiveness of the wet scrubber is evaluated with an annual stack test and visible emissions measurement. A detailed description of the control equipment is included in the Title V renewal application (Attachment ASA-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. 3	Indicator No. 1	Indicator No. 2
Indicator	Total pressure drop across the scrubber.	Total water flow rate through the scrubber.
Measurement Approach	Pressure drop is monitored with a pressure transducer.	The scrubber water flow rate is measured using an orifice meter.
Indicator Range	An excursion is defined as any individual pressure drop below 3.3 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any individual water flow rate below 310 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a pressure transducer, which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.01 inches of water gauge pressure.	The scrubber water orifice meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5%.
Verification of Operational Status	Readout in boiler control room.	Readout in boiler control room.
QA/QC Practices and Criteria	The pressure transducer is maintained in accordance with the manufacturer's recommendations.	The orifice 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 eight (8) hours.	Reading taken once every eight (8) hours.
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.

Scrubber inlet water supply pressure is currently monitored for Boiler No. 3, 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.

Atlantic Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and water flow rate to the Boiler No. 3 wet scrubber. The test data correlating the parameters to the PM emission levels are presented in Figure 4-1 and Figure 4-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values from each one-hour test run, using the historic test data. The calculation of the minimum parameter values are provided below:

Pressure Drop: Minimum test run value = 3.62 in. H_2O
Minimum parameter value = 3.62 x 0.9 = 3.3 in. H_2O

Water Flow Rate: Minimum test run value = 345 gpm
Minimum parameter value = 345 x 0.9 = 310 gpm

Wet scrubber operating parameter values below these minimum parameter values would be 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 (4) times per hour. However, 40 CFR 63.3(b)(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.

ASA has been recording scrubber parameters once per 8-hour shift, according to the current Title V permit conditions. Although ASA 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 would 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.

Figure 4-1. ASA Boiler No. 3
PM vs. Pressure Drop

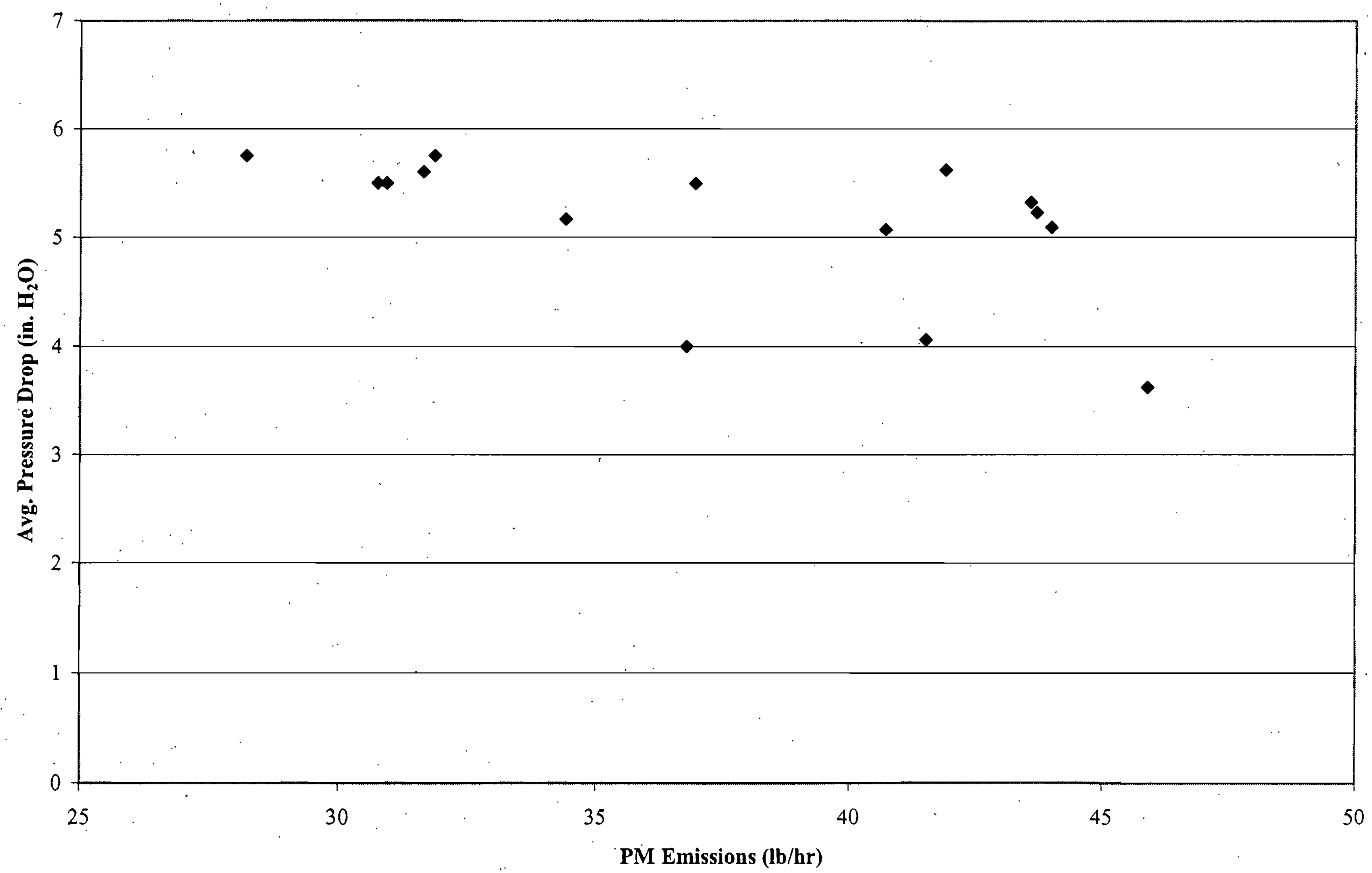
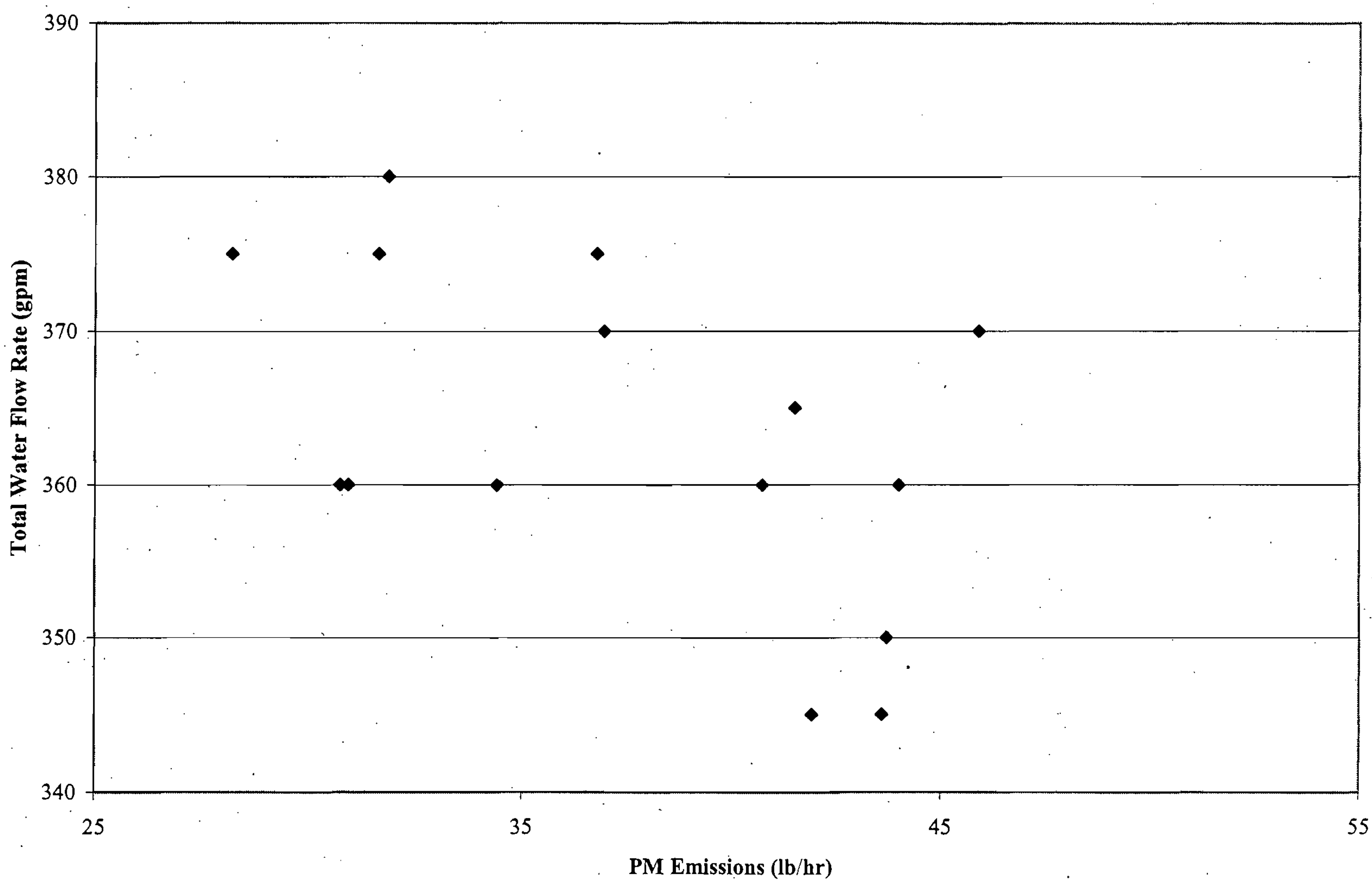


Figure 4-2. ASA Boiler No. 3
PM vs. Total Water Flow Rate



5.0 PARTICULATE MATTER EMISSIONS FROM BOILER NO. 4

5.1 EMISSIONS UNIT IDENTIFICATION

Boiler No. 4—EU ID 004

5.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 4 has a PM emission limit of 0.29 lb/MMBtu for carbonaceous fuel, plus 0.10 lb/MMBtu for No. 6 fuel oil [Rule 62-296.410(1)(b)2, F.A.C.]. The equivalent potential emissions are 73.7 lb/hr and 160.9 TPY for carbonaceous fuel and 3.8 lb/hr and 8.3 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. Visible emission limits shall be effective only if the visible emission measurement can be made without being substantially affected by plume mixing or moisture condensation (Permit No. 0990016-006-AV).

PM and VE compliance testing is required annually on Boiler No. 4. 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. 0990016-006-AV).

5.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 4 are controlled by a Joy type Impingement Scrubber (equivalent to Type D). The scrubber exhausts through a 90-foot stack.

The design pressure drop across the scrubber is 4 to 7 in. H_2O. The design water inlet pressure to the scrubber is 50 to 80 psig. The design water flow rate to the scrubber is 300 to 400 gpm. The effectiveness of the wet scrubber is evaluated with an annual stack test and visible emissions measurement. A detailed description of the control equipment is included in the Title V renewal application (Attachment ASA-EU4-I3).

5.4 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	Total pressure drop across the scrubber.	Total water flow rate through the scrubber.
Measurement Approach	Pressure drop is monitored with a pressure transducer.	The scrubber water flow rate is measured using an orifice meter.
Indicator Range	An excursion is defined as any individual pressure drop below 3.8 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any individual water flow rate below 310 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a pressure transducer, which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.01 inches of water gauge pressure.	The scrubber water orifice meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5%.
Verification of Operational Status	Readout in boiler control room.	Readout in boiler control room.
QA/QC Practices and Criteria	The pressure transducer is maintained in accordance with the manufacturer's recommendations.	The orifice 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 eight (8) hours.	Reading taken once every eight (8) hours.
Averaging Period	NA	NA

5.5 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.

Scrubber inlet water supply pressure is currently monitored for Boiler No. 4, 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.

Atlantic 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 are presented in Figure 5-1 and Figure 5-2. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based 90 percent of the minimum parameter values from the 1-hour test runs, using the historic test data. The calculation of the minimum parameter values are provided below:

Pressure Drop: Minimum test run value = 4.20 in. H_2O
Minimum parameter value = 4.20 x 0.9 = 3.8 in. H_2O

Water Flow Rate: Minimum test run value = 345 gpm
Minimum parameter value = 345 x 0.9 = 310 gpm

Wet scrubber operating parameter values below these minimum parameter values would be 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 63.3(b)(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.

ASA has been recording scrubber parameters once per 8-hour shift, according to the current Title V permit conditions. Although ASA 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 would 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.

Figure 5-1. ASA Boiler No. 4
PM vs. Pressure Drop

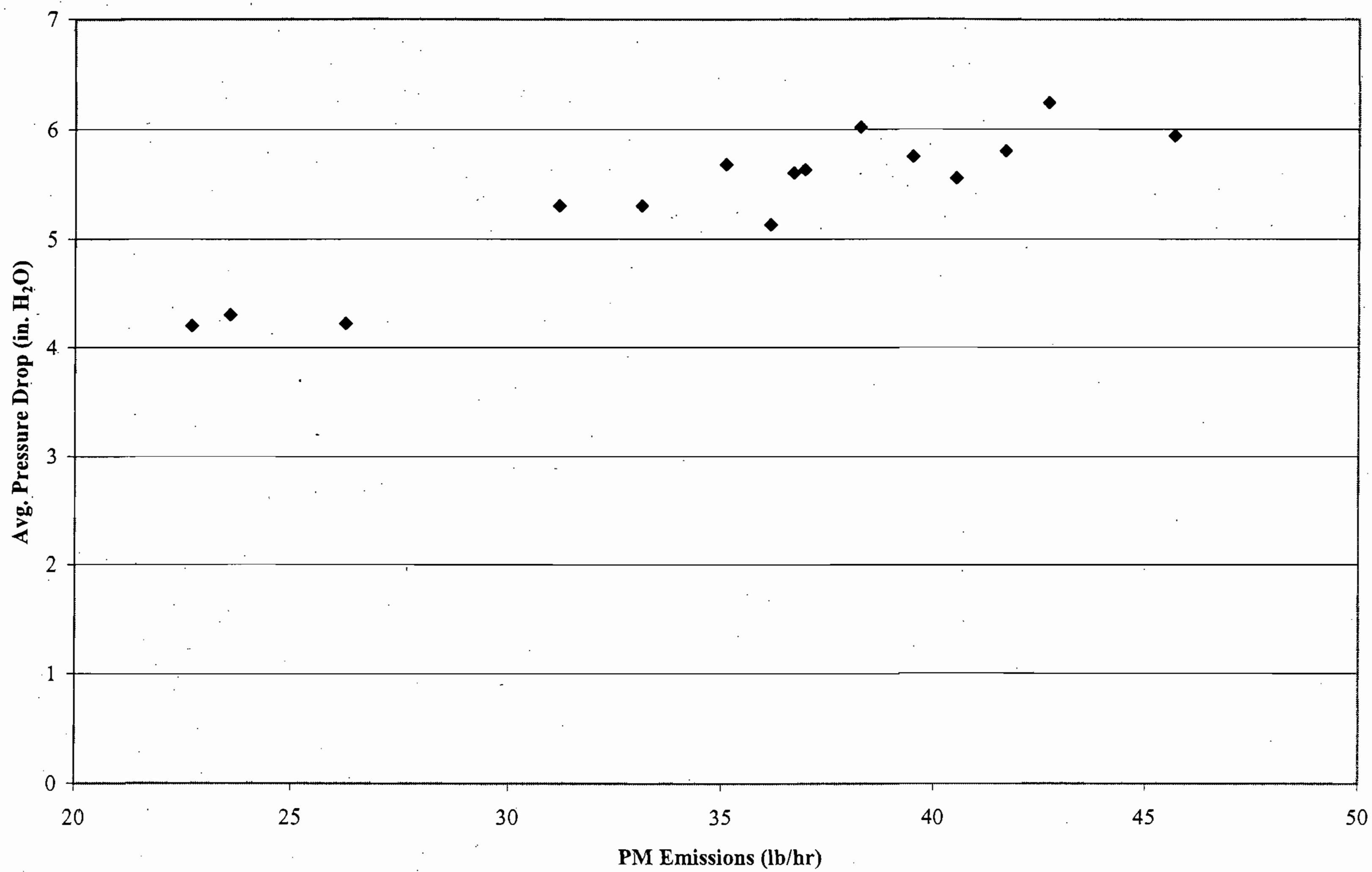
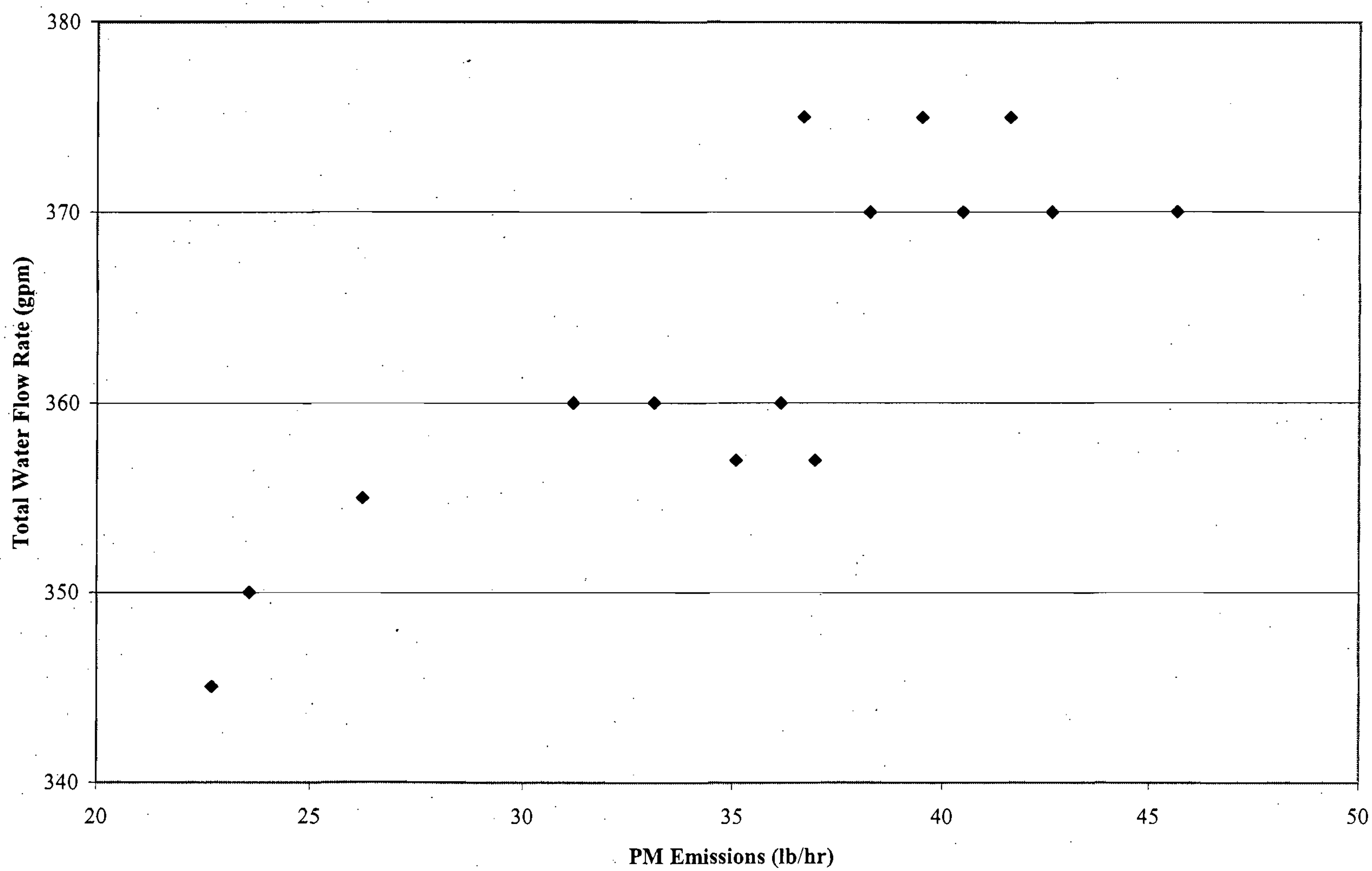


Figure 5-2. ASA Boiler No. 4
PM vs. Total Water Flow Rate



6.0 PARTICULATE MATTER EMISSIONS FROM BOILER NO. 5

6.1 EMISSIONS UNIT IDENTIFICATION

Boiler No. 5—EU ID 005

6.2 APPLICABLE REGULATIONS, EMISSIONS LIMITS, AND MONITORING REQUIREMENTS

Boiler No. 5 has a PM/PM_{10} emission limit of 0.15 lb/MMBtu for carbonaceous fuel, plus 0.10 lb/MMBtu for No. 6 fuel oil [Rules 62-296.410(2)(b)2. and 62-212.400 (BACT), F.A.C.]. The equivalent potential emissions are 38.3 lb/hr and 65.0 TPY for carbonaceous fuel and 7.05 lb/hr and 1.5 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. 0990016-006-AV).

PM and VE compliance testing is required annually on Boiler No. 5. 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. 0990016-006-AV).

6.3 CONTROL TECHNOLOGY DESCRIPTION

PM emissions from Boiler No. 5 are controlled by a Type D Joy Turbulaire wet impingement scrubber. The design pressure drop across the scrubber is 7 to 11 in. H_2O. The design water inlet pressure to the scrubber is 60 to 80 psig. The design total water flow rate to the scrubber is 900 to 2,000 gpm. The effectiveness of the wet scrubber is evaluated with an annual stack test and visible emissions measurement. A detailed description of the control equipment is included in the Title V renewal application (Attachment ASA-EU5-I3).

6.4 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	Total pressure drop across the scrubber.	Total water flow rate through the scrubber.
Measurement Approach	Pressure drop is monitored with a pressure transducer.	The scrubber water flow rate is measured using an orifice meter.
Indicator Range	An excursion is defined as any individual pressure drop below 7.4 in. H_2O. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.	An excursion is defined as any individual water flow rate below 225 gpm. Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement.
Data Representativeness	The monitoring system consists of a pressure transducer which measures the pressure drop across the scrubber. The minimum accuracy of the device is ±0.01 inches of water gauge pressure.	The scrubber water orifice meter is located on the scrubber liquid supply line. The minimum accuracy of the device is ±5%.
Verification of Operational Status	Readout in boiler control room.	Readout in boiler control room.
QA/QC Practices and Criteria	The pressure transducer is maintained in accordance with the manufacturer's recommendations.	The orifice 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 eight (8) hours.	Reading taken once every eight (8) hours.
Averaging Period	NA	NA

6.5 JUSTIFICATION

Both pressure drop across the scrubber and water flow rate to the scrubber are recognized parameters for controlling PM/PM_{10} 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.

Scrubber inlet water supply pressure is currently monitored for Boiler No. 5, 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.

Atlantic Sugar has sufficient historic test data necessary to establish indicator values for pressure drop and water flow rate to the Boiler No. 5 wet scrubber. The test data correlating the parameters to the PM/PM_{10} emission levels are presented in Figure 6-1 and Figure 6-2. Figure 6-1 contains three data point outliers (pressure drop between 2 and 4 in. H_2O) that are not considered in the indicator range determination. From the figure, there is little correlation between the average pressure drop and PM/PM_{10} emission rate. Therefore, it is proposed that the current indicator range as given in Permit No. 0990016-006-AV be changed. A single minimum scrubber pressure drop value is proposed to be maintained, regardless of steam production rate. Supporting information is contained in Appendix B.

The proposed parameter minimum values are based on 90 percent of the minimum parameter values from the test runs, using the historic test data. The calculation of the minimum parameter values are provided below:

Pressure Drop: Minimum test run value = 7.5 in. H_2O
Minimum parameter value = 7.5 x 0.9 = 6.8 in. H_2O

Total Water Flow Rate: Minimum test run value = 920 gpm
Minimum parameter value = 920 x 0.9 = 828 gpm

Wet scrubber operating parameter values below these minimum parameter values would be 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. 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 (4) times per hour. However, 40 CFR 63.3(b)(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.

ASA has been recording scrubber parameters once per 8-hour shift, according to the current Title V permit conditions. Although ASA 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 would 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.

Figure 6-1. ASA Boiler No. 5
PM/PM_{10} vs. Pressure Drop

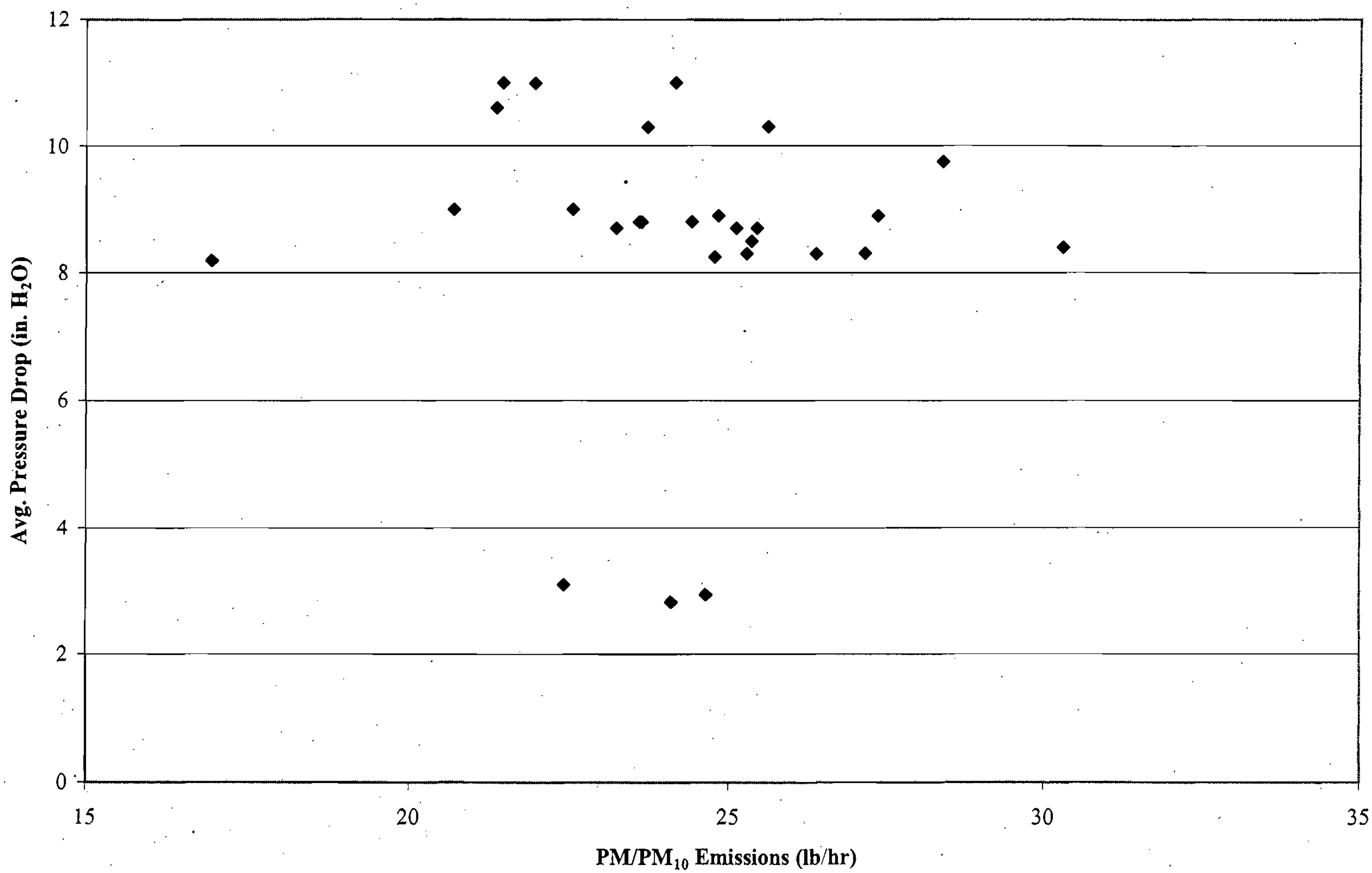
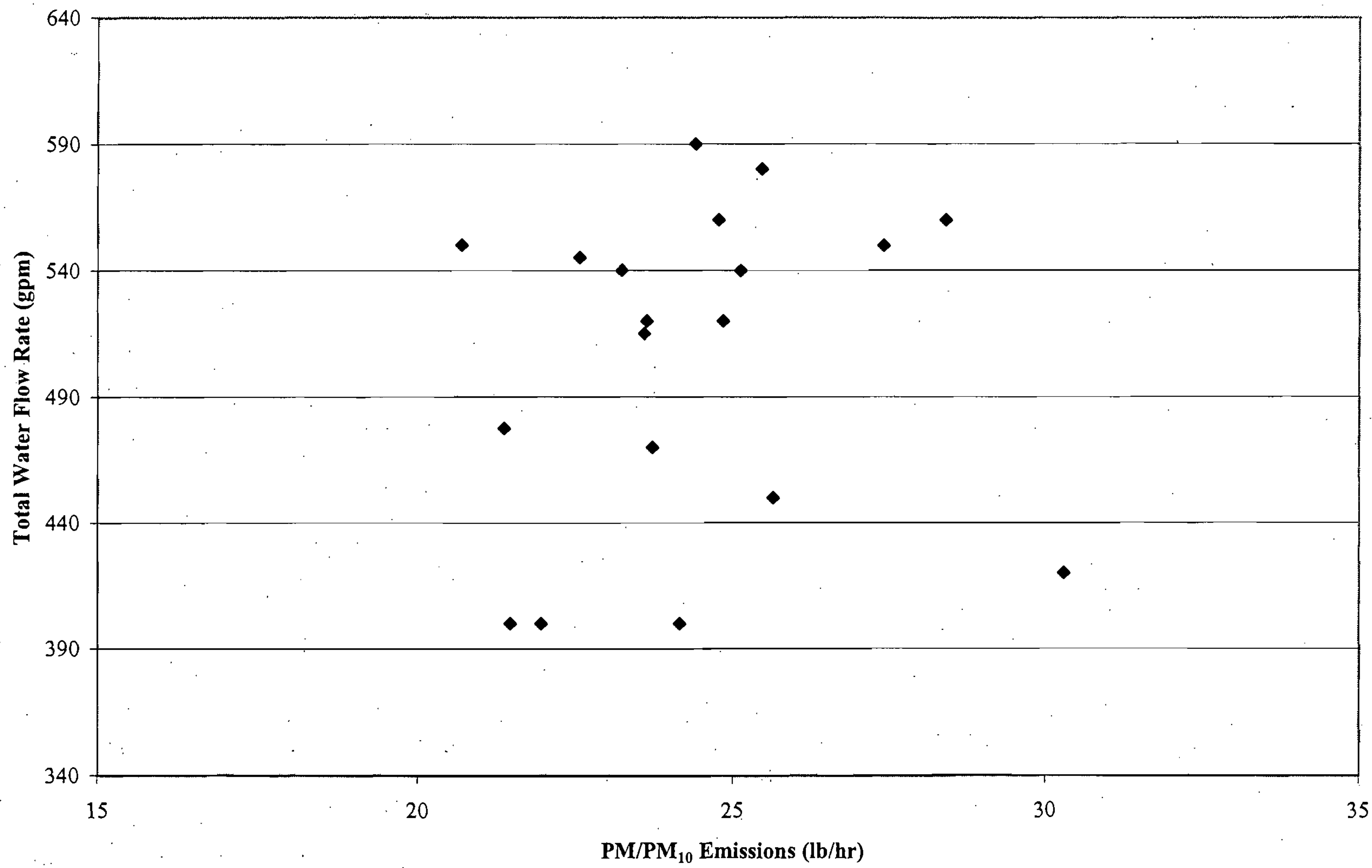


Figure 6-2. ASA Boiler No. 5
PM/PM_{10} vs. Total Water Flow Rate



APPENDIX A

SIGNATURE PAGES

FACILITY 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:
   John A. Fanjul, Vice President and General Manager

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☒ 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: **Atlantic Sugar Association, Inc.**
   Street Address: **SR 880 - 16 mi. E of Belle Glade**
   City: **Belle Glade** State: **FL** Zip Code: **33430**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(561) 996-6541** ext. Fax: **(561) 996-8021**

5. Application Responsible Official Email Address: **John_Fanjul@floridacrystals.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 ______ Date 7/7/05

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**
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 7/7/05 Signature Date (seal)

* Attach any exception to certification statement.
** Board of Professional Engineers Certificate of Authorization #00001670

APPENDIX B

HISTORIC PM COMPLIANCE TEST DATA
FOR BOILER NOS. 1 -5

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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	Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
Boiler 1	1	Dumping Grate	02/16/93	60,778	--	131,400	249.9	34.71	74.97	0.30	--	--			
Boiler 1	2	Dumping Grate	02/16/93	59,686	--	135,000	256.5	35.63	76.95	0.30	--	--			
Boiler 1	3	Dumping Grate	02/16/93	59,217	--	133,600	251.9	34.99	75.57	0.30	--	--			
Boiler 1	1	Dumping Grate	11/30/93	48,406	--	126,400	237.6	33.00	71.28	0.30	--	--			
Boiler 1	2	Dumping Grate	11/30/93	50,748	--	121,933	228.0	31.67	68.40	0.30	--	--			
Boiler 1	3	Dumping Grate	11/30/93	52,199	--	122,712	230.0	31.94	69.00	0.30	--	--			
Boiler 1	1	Dumping Grate	12/01/93	48,262	--	134,000	249.4	34.64	74.82	0.30	41.28	0.166			
Boiler 1	2	Dumping Grate	12/01/93	49,288	--	136,029	252.8	35.11	75.84	0.30	40.88	0.162			
Boiler 1	3	Dumping Grate	12/01/93	51,382	--	130,615	243.5	33.82	73.05	0.30	33.93	0.139			
Boiler 1	1	Dumping Grate	12/19/94	56,029	--	110,786	200.3	27.82	60.09	0.30	--	--			
Boiler 1	2	Dumping Grate	12/19/94	58,853	--	110,786	208.5	28.96	62.55	0.30	--	--			
Boiler 1	3	Dumping Grate	12/19/94	53,938	--	110,786	218.0	30.28	65.40	0.30	--	--			
Boiler 1	1	Dumping Grate	12/14/95	58,710	--	126,200	241.6	33.56	72.48	0.30	44.69	0.185			
Boiler 1	2	Dumping Grate	12/14/95	58,138	--	130,600	252.0	35.00	75.60	0.30	40.61	0.161			
Boiler 1	3	Dumping Grate	12/14/95	52,858	--	129,800	250.4	34.78	75.12	0.30	42.28	0.169			
Boiler 1	1	Dumping Grate	12/11/96	47,080	--	132,500	260.2	36.14	78.06	0.30	37.00	0.142			
Boiler 1	2	Dumping Grate	12/11/96	50,116	--	139,700	270.2	37.53	81.06	0.30	44.09	0.163			
Boiler 1	3	Dumping Grate	12/11/96	46,486	--	138,700	269.3	37.40	80.79	0.30	35.24	0.131			
Boiler 1	1	Dumping Grate	01/09/98	71,108	--	130,400	250.2	34.75	75.06	0.30	58.60	0.234			
Boiler 1	2	Dumping Grate	01/09/98	70,939	--	129,700	249.9	34.71	74.97	0.30	53.80	0.215			
Boiler 1	3	Dumping Grate	01/09/98	70,490	--	130,200	249.8	34.69	74.94	0.30	59.00	0.236			
Boiler 1	1	Dumping Grate	11/24/98	60,323	--	131,000	245.5	34.10	73.65	0.30	44.93	0.183			
Boiler 1	2	Dumping Grate	11/24/98	59,319	--	131,600	246.2	34.19	73.86	0.30	50.49	0.205			
Boiler 1	3	Dumping Grate	11/24/98	61,597	--	131,600	246.5	34.24	73.95	0.30	55.15	0.224			
Boiler 1	1	Dumping Grate	12/17/99	60,655	--	134,100	248.7	34.54	74.61	0.30	37.44	0.151		345	6.20
Boiler 1	2	Dumping Grate	12/17/99	60,467	--	134,400	249.2	34.61	74.76	0.30	39.97	0.160		345	6.05
Boiler 1	3	Dumping Grate	12/17/99	63,036	--	134,000	250.9	34.85	75.27	0.30	51.13	0.204		345	5.75
Boiler 1	1	Dumping Grate	12/01/00	63,507	--	139,100	261.8	36.36	78.54	0.30	34.96	0.134		340	6.80
Boiler 1	2	Dumping Grate	12/01/00	64,188	--	137,700	259.2	36.00	77.76	0.30	31.82	0.123		340	6.50
Boiler 1	3	Dumping Grate	12/01/00	61,815	--	138,700	261.2	36.28	78.36	0.30	36.76	0.141		340	6.50
Boiler 1	1	Dumping Grate	12/07/01	58,535	--	126,080	247.7	34.40	74.31	0.30	58.04	0.234		345	4.15
Boiler 1	2	Dumping Grate	12/07/01	62,628	--	126,300	248.0	34.44	74.40	0.30	52.33	0.211		345	4.57
Boiler 1	3	Dumping Grate	12/07/01	63,652	--	126,300	248.1	34.46	74.43	0.30	48.41	0.195		345	4.30
Boiler 1	1	Dumping Grate	12/17/02	72,636	--	124,600	240.1	33.35	72.03	0.30	43.50	0.181		365	4.54
Boiler 1	2	Dumping Grate	12/17/02	70,555	--	133,500	258.9	35.96	77.67	0.30	56.40	0.218		365	4.58
Boiler 1	3	Dumping Grate	12/17/02	67,219	--	129,600	250.7	34.82	75.21	0.30	58.90	0.235		365	4.63
Boiler 1	1	Dumping Grate	12/05/03	63,497	--	135,134	258.2	35.86	77.46	0.30	48.18	0.187		370	5.15
Boiler 1	2	Dumping Grate	12/05/03	62,865	--	136,400	261.3	36.29	78.39	0.30	45.59	0.174		370	5.22
Boiler 1	3	Dumping Grate	12/05/03	64,246	--	125,100	240.1	33.35	72.03	0.30	48.16	0.201	70.0	370	5.28
Boiler 1	1	Dumping Grate	12/10/04		104,914	142,800	277.2	38.50	83.16	0.30	50.27	0.181	72.0	370	5.38
Boiler 1	2	Dumping Grate	12/10/04		101,057	140,215	272.3	37.82	81.69	0.30	54.50	0.200	72.6	366	5.30
Boiler 1	3	Dumping Grate	12/10/04		102,057	138,738	266.2	36.97	79.86	0.30	55.24	0.208	72.6	365	5.30

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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	Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
Boiler 2	1	Dumping Grate	02/05/93	65,571	--	123,200	240.5	33.40	72.15	0.30	66.17	0.275			
Boiler 2	2	Dumping Grate	02/05/93	71,680	--	120,900	235.9	32.76	70.77	0.30	74.47	0.316			
Boiler 2	3	Dumping Grate	02/05/93	64,657	--	122,500	238.5	33.13	71.55	0.30	67.72	0.284			
Boiler 2	1	Dumping Grate	02/22/93	75,436	--	102,600	201.3	27.96	60.39	0.30	--	--			
Boiler 2	2	Dumping Grate	02/22/93	70,834	--	124,400	244.1	33.90	73.23	0.30	--	--			
Boiler 2	3	Dumping Grate	02/22/93	71,240	--	110,600	217.0	30.14	65.10	0.30	--	--			
Boiler 2	1	Dumping Grate	12/02/93	47,783	--	123,900	236.6	32.86	70.98	0.30	--	--			
Boiler 2	2	Dumping Grate	12/02/93	49,827	--	126,400	242.8	33.72	72.84	0.30	--	--			
Boiler 2	3	Dumping Grate	12/02/93	48,382	--	125,200	240.5	33.40	72.15	0.30	--	--			
Boiler 2	1	Dumping Grate	12/03/93	52,900	--	130,971	252.0	35.00	75.60	0.30	46.12	0.183			
Boiler 2	2	Dumping Grate	12/03/93	51,929	--	124,629	239.3	33.24	71.79	0.30	46.58	0.195			
Boiler 2	3	Dumping Grate	12/03/93	52,753	--	117,957	226.9	31.51	68.07	0.30	34.01	0.150			
Boiler 2	1	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	2	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	3	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	4	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	5	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	6	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	7	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	8	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	9	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	10	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	11	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	12	Dumping Grate	02/28/94	63,327	--	118,629	225.3	31.30	67.60	0.30	--	--			
Boiler 2	1	Dumping Grate	01/09/95	67,247	--	103,900	195.9	27.21	58.77	0.30	--	--			
Boiler 2	2	Dumping Grate	01/09/95	72,034	--	112,000	211.0	29.31	63.30	0.30	--	--			
Boiler 2	3	Dumping Grate	01/09/95	71,264	--	101,524	191.7	26.63	57.51	0.30	--	--			
Boiler 2	1	Dumping Grate	02/03/95	67,603	--	111,273	210.6	29.25	63.18	0.30	41.32	0.196			
Boiler 2	1	Dumping Grate	12/12/95	70,293	--	120,100	229.1	31.82	68.73	0.30	45.76	0.200			
Boiler 2	2	Dumping Grate	12/12/95	70,747	--	120,500	229.7	31.90	68.91	0.30	49.09	0.214			
Boiler 2	3	Dumping Grate	12/12/95	69,607	--	119,600	228.0	31.67	68.40	0.30	43.98	0.193			
Boiler 2	1	Dumping Grate	12/13/96	71,628	--	119,360	228.4	31.72	68.52	0.30	51.31	0.225			
Boiler 2	2	Dumping Grate	12/13/96	51,310	--	120,600	232.1	32.24	69.63	0.30	37.80	0.163			
Boiler 2	3	Dumping Grate	12/13/96	52,769	--	122,500	235.3	32.68	70.59	0.30	50.77	0.216			
Boiler 2	1	Dumping Grate	01/07/98	85,556	--	129,920	246.9	34.29	74.07	0.30	63.00	0.255			
Boiler 2	2	Dumping Grate	01/07/98	81,927	--	134,560	258.2	35.86	77.46	0.30	64.10	0.248			
Boiler 2	3	Dumping Grate	01/07/98	80,849	--	129,750	248.7	34.54	74.61	0.30	60.20	0.242			
Boiler 2	1	Dumping Grate	11/24/98	69,538	--	130,700	240.4	33.39	72.12	0.30	71.48	0.297			
Boiler 2	2	Dumping Grate	11/24/98	68,666	--	130,600	240.4	33.39	72.12	0.30	64.20	0.267			
Boiler 2	3	Dumping Grate	11/24/98	70,268	--	132,500	243.8	33.86	73.14	0.30	74.34	0.305			
Boiler 2	1	Dumping Grate	12/14/99	51,373	--	126,100	241.8	33.58	72.54	0.30	52.02	0.215		382	5.50
Boiler 2	2	Dumping Grate	12/14/99	53,552	--	126,200	242.5	33.68	72.75	0.30	51.88	0.214		435	5.50
Boiler 2	3	Dumping Grate	12/14/99	54,556	--	130,500	249.0	34.58	74.70	0.30	48.61	0.195		400	5.50
Boiler 2	1	Dumping Grate	12/05/00	66,989	--	130,500	251.1	34.88	75.33	0.30	52.58	0.209		420	5.60
Boiler 2	2	Dumping Grate	12/05/00	69,482	--	137,760	267.8	37.19	80.34	0.30	53.82	0.201		420	5.40
Boiler 2	3	Dumping Grate	12/05/00	63,682	--	136,200	264.8	36.78	79.44	0.30	53.67	0.203		420	5.60
Boiler 2	1	Dumping Grate	12/05/01	66,338	--	120,900	234.8	32.61	70.44	0.30	47.75	0.203		355	4.51

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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)		Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			
Boiler 2	2	Dumping Grate	12/05/01	64,700	--	125,077	241.6	33.56	72.48	0.30	46.75	0.194		355	5.00
Boiler 2	3	Dumping Grate	12/05/01	64,556	--	121,300	234.4	32.56	70.32	0.30	58.00	0.247		355	5.00
Boiler 2	1	Dumping Grate	12/31/02	66,302	--	120,800	230.9	32.07	69.27	0.30	62.61	0.271		345	5.75
Boiler 2	2	Dumping Grate	12/31/02	66,787	--	122,900	234.8	32.61	70.44	0.30	66.41	0.283		345	5.82
Boiler 2	3	Dumping Grate	12/31/02	64,352	--	122,550	233.9	32.49	70.17	0.30	56.82	0.243		345	5.86
Boiler 2	1	Dumping Grate	12/03/03	54,995	--	124,110	239.9	33.32	71.97	0.30	63.72	0.266		355	5.47
Boiler 2	2	Dumping Grate	12/03/03	60,898	--	119,304	230.3	31.99	69.09	0.30	69.48	0.302		355	5.64
Boiler 2	3	Dumping Grate	12/03/03	59,146	--	120,738	232.9	32.35	69.87	0.30	55.19	0.237		355	5.65
Boiler 2	1	Dumping Grate	12/03/04		101,493	119,262	228.6	31.75	68.58	0.30	69.28	0.303	72.0	375	4.31
Boiler 2	2	Dumping Grate	12/03/04		102,972	127,100	243.8	33.86	73.14	0.30	63.10	0.259	70.8	375	4.44
Boiler 2	3	Dumping Grate	12/03/04		102,061	126,369	242.6	33.69	72.78	0.30	60.78	0.251	70.6	375	4.45

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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)		Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			
Boiler 3	1	Cell	02/23/93	78,209	--	118,600	236.00	32.78	70.80	0.30	26.30	0.111			
Boiler 3	2	Cell	02/23/93	73,332	--	118,800	237.20	32.94	71.16	0.30	38.90	0.164			
Boiler 3	3	Cell	02/23/93	72,363	--	112,000	223.40	31.03	67.02	0.30	27.60	0.124			
Boiler 3	1	Cell	11/19/93	67,535	--	103,216	200.00	27.78	60.00	0.30	54.26	0.271			
Boiler 3	2	Cell	11/19/93	67,280	--	111,818	216.66	30.09	65.00	0.30	49.84	0.230			
Boiler 3	3	Cell	11/19/93	66,731	--	115,600	223.72	31.07	67.12	0.30	52.03	0.233			
Boiler 3	1	Cell	11/22/93	66,893	--	112,579	217.63	30.23	65.29	0.30	50.55	0.232			
Boiler 3	2	Cell	11/22/93	64,767	--	114,348	224.16	31.13	67.25	0.30	52.45	0.234			
Boiler 3	3	Cell	11/22/93	66,954	--	113,577	219.76	30.52	65.93	0.30	56.06	0.255			
Boiler 3	1	Cell	01/24/95	68,682	--	132,333	259.33	36.02	77.80	0.30	53.64	0.207			
Boiler 3	2	Cell	01/24/95	71,531	--	133,612	261.56	36.33	78.47	0.30	51.01	0.195			
Boiler 3	3	Cell	01/24/95	67,850	--	121,754	235.45	32.70	70.64	0.30	62.90	0.267			
Boiler 3	1	Cell	01/25/95	68,305	--	118,459	233.24	32.39	69.97	0.30	43.92	0.188			
Boiler 3	2	Cell	01/25/95	68,267	--	124,875	246.34	34.21	73.90	0.30	55.62	0.226			
Boiler 3	3	Cell	01/25/95	65,987	--	125,015	246.23	34.20	73.87	0.30	56.43	0.229			
Boiler 3	1	Cell	11/28/95	73,497	--	123,636	242.46	33.68	72.74	0.30	44.95	0.185			
Boiler 3	2	Cell	11/28/95	75,168	--	119,000	233.71	32.46	70.11	0.30	46.87	0.201			
Boiler 3	3	Cell	11/28/95	73,660	--	123,634	244.99	34.03	73.50	0.30	38.83	0.158			
Boiler 3	1	Cell	11/25/96	75,658	--	116,829	233.80	32.47	70.14	0.30	47.46	0.203			
Boiler 3	2	Cell	11/25/96	76,019	--	118,800	237.80	33.03	71.34	0.30	48.56	0.204			
Boiler 3	3	Cell	11/25/96	75,572	--	126,909	254.30	35.32	76.29	0.30	47.50	0.187			
Boiler 3	1	Cell	12/09/97	61,753	--	116,833	231.60	32.17	69.48	0.30	34.16	0.147			
Boiler 3	2	Cell	12/09/97	63,156	--	107,273	212.60	29.53	63.78	0.30	30.68	0.144			
Boiler 3	3	Cell	12/09/97	61,661	--	114,522	227.10	31.54	68.13	0.30	34.41	0.151			
Boiler 3	1	Cell	12/10/98	72,603	--	108,441	209.90	29.15	62.97	0.30	39.45	0.188			
Boiler 3	2	Cell	12/10/98	73,269	--	119,104	231.30	32.13	69.39	0.30	41.24	0.178			
Boiler 3	3	Cell	12/10/98	71,667	--	121,791	235.60	32.72	70.68	0.30	42.09	0.179			
Boiler 3	1	Cell	11/19/99	74,718	--	117,000	226.28	31.43	67.88	0.30	57.12	0.252		350	
Boiler 3	2	Cell	11/19/99	70,779	--	123,938	239.67	33.29	71.90	0.30	50.95	0.213		350	
Boiler 3	3	Cell	11/19/99	72,979	--	118,523	229.24	31.84	68.77	0.30	50.08	0.218		350	
Boiler 3	1	Cell	12/19/00	70,383	--	99,000	195.33	27.13	58.60	0.30	30.73	0.157		360	5.50
Boiler 3	2	Cell	12/19/00	72,534	--	105,134	206.39	28.67	61.92	0.30	36.95	0.179		370	5.50
Boiler 3	3	Cell	12/19/00	69,399	--	102,806	202.84	28.17	60.85	0.30	30.91	0.152		360	5.50
Boiler 3	1	Cell	11/27/01	56,933	--	114,185	221.87	30.82	66.56	0.30	28.21	0.127		375	5.75
Boiler 3	2	Cell	11/27/01	58,993	--	113,169	220.12	30.57	66.04	0.30	31.84	0.145		380	5.75
Boiler 3	3	Cell	11/27/01	59,823	--	112,031	218.56	30.36	65.57	0.30	31.62	0.145		375	5.60
Boiler 3	4	Cell	11/27/01	59,717	--	110,762	217.17	30.16	65.15	0.30	--	--		380	5.90
Boiler 3	1	Cell	12/04/02	70,832	--	122,320	237.96	33.05	71.39	0.30	40.74	0.171	60.0	360	5.07
Boiler 3	2	Cell	12/04/02	73,585	--	119,818	237.77	33.02	71.33	0.30	34.41	0.145	60.0	360	5.17
Boiler 3	3	Cell	12/04/02	75,214	--	120,090	236.63	32.87	70.99	0.30	44.01	0.186	60.0	360	5.09
Boiler 3	1	Cell	11/13/03	60,287	--	123,333	239.80	33.31	71.94	0.30	36.78	0.153	68.0	375	4.00
Boiler 3	2	Cell	11/13/03	61,707	--	125,135	243.55	33.83	73.07	0.30	45.91	0.189	65.0	370	3.62
Boiler 3	3	Cell	11/13/03	63,339	--	124,435	243.03	33.75	72.91	0.30	41.54	0.171	66.0	365	4.06
Boiler 3	1	Cell	11/09/04	60,803	99,693	118,388	238.66	33.15	71.60	0.30	43.60	0.183	70.0	345	5.32
Boiler 3	2	Cell	11/09/04	56,928	99,678	121,217	243.43	33.81	73.03	0.30	43.72	0.180	70.0	350	5.23
Boiler 3	3	Cell	11/09/04	56,172	99,868	122,700	247.85	34.42	74.36	0.30	41.93	0.169	70.0	345	5.62

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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	Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
Boiler 4	1	Cell	02/24/93	71,081	--	114,000	223.50	31.04	64.82	0.29	--	--			
Boiler 4	2	Cell	02/24/93	73,402	--	114,400	224.30	31.15	65.05	0.29	--	--			
Boiler 4	3	Cell	02/24/93	69,540	--	117,400	231.80	32.19	67.22	0.29	--	--			
Boiler 4	1	Cell	11/23/93	73,234	--	112,833	218.40	30.33	63.34	0.29	41.68	0.191			
Boiler 4	2	Cell	11/23/93	70,019	--	119,104	231.28	32.12	67.07	0.29	42.01	0.182			
Boiler 4	3	Cell	11/23/93	69,704	--	120,079	231.27	32.12	67.07	0.29	50.53	0.218			
Boiler 4	1	Cell	11/24/93	74,684	--	120,909	233.68	32.46	67.77	0.29	56.45	0.242			
Boiler 4	2	Cell	11/24/93	75,794	--	116,636	225.49	31.32	65.39	0.29	52.91	0.235			
Boiler 4	3	Cell	11/24/93	73,386	--	113,194	218.73	30.38	63.43	0.29	50.93	0.233			
Boiler 4	1	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	2	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	3	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	4	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	5	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	6	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	7	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	8	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	9	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	10	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	11	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	12	Cell	03/01/94	70,087	--	92,575	178.06	24.73	51.64	0.29	--	--			
Boiler 4	1	Cell	11/30/94	76,163	--	116,429	221.19	30.72	64.15	0.29	41.08	0.186			
Boiler 4	2	Cell	11/30/94	74,391	--	117,623	224.70	31.21	65.16	0.29	27.14	0.121			
Boiler 4	3	Cell	11/30/94	75,714	--	116,164	221.13	30.71	64.13	0.29	42.26	0.191			
Boiler 4	1	Cell	12/02/94	74,946	--	110,382	215.62	29.95	62.53	0.29	46.75	0.217			
Boiler 4	2	Cell	12/02/94	74,911	--	112,412	218.68	30.37	63.42	0.29	40.89	0.187			
Boiler 4	3	Cell	12/02/94	75,872	--	111,524	217.77	30.25	63.15	0.29	42.71	0.196			
Boiler 4	1	Cell	11/21/95	67,650	--	123,273	240.80	33.44	69.83	0.29	43.02	0.179			
Boiler 4	2	Cell	11/21/95	70,676	--	124,807	241.73	33.57	70.10	0.29	44.90	0.186			
Boiler 4	3	Cell	11/21/95	70,587	--	124,543	242.24	33.64	70.25	0.29	46.60	0.192			
Boiler 4	1	Cell	11/26/96	77,761	--	100,886	197.86	27.48	57.38	0.29	45.45	0.230			
Boiler 4	2	Cell	11/26/96	77,763	--	102,265	200.01	27.78	58.00	0.29	46.20	0.231			
Boiler 4	3	Cell	11/26/96	75,473	--	105,857	206.52	28.68	59.89	0.29	45.68	0.221			
Boiler 4	1	Cell	12/10/97	60,926	--	113,676	223.40	31.03	64.79	0.29	43.08	0.193			
Boiler 4	2	Cell	12/10/97	63,700	--	116,328	228.20	31.69	66.18	0.29	45.11	0.198			
Boiler 4	3	Cell	12/10/97	63,560	--	116,507	228.50	31.74	66.27	0.29	42.95	0.188			
Boiler 4	1	Cell	12/09/98	68,506	--	112,388	215.30	29.90	62.44	0.29	38.37	0.178			
Boiler 4	2	Cell	12/09/98	68,576	--	108,627	208.10	28.90	60.35	0.29	39.92	0.192			
Boiler 4	3	Cell	12/09/98	66,197	--	108,636	208.20	28.92	60.38	0.29	31.98	0.154			
Boiler 4	1	Cell	11/18/99	69,198	--	111,353	217.53	30.21	63.08	0.29	39.83	0.183		370	
Boiler 4	2	Cell	11/18/99	69,648	--	115,075	223.76	31.08	64.89	0.29	43.08	0.193		370	
Boiler 4	3	Cell	11/18/99	68,934	--	115,938	225.44	31.31	65.38	0.29	47.68	0.211		370	
Boiler 4	1	Cell	12/21/00	71,568	--	99,273	194.68	27.04	56.46	0.29	36.16	0.186		360	5.13
Boiler 4	2	Cell	12/21/00	70,348	--	102,091	199.17	27.66	57.76	0.29	33.13	0.166		360	5.30
Boiler 4	3	Cell	12/21/00	69,435	--	106,800	210.51	29.24	61.05	0.29	31.19	0.148		360	5.30
Boiler 4	1	Cell	11/29/01	68,767	--	115,200	225.48	31.32	65.39	0.29	41.64	0.185		375	5.80

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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	Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
Boiler 4	2	Cell	11/29/01	68,859	--	119,723	234.76	32.61	68.08	0.29	36.70	0.156		375	5.60
Boiler 4	3	Cell	11/29/01	64,781	--	122,250	239.70	33.29	69.51	0.29	39.50	0.165		375	5.75
Boiler 4	1	Cell	12/06/02	65,133	--	117,403	230.71	32.04	66.91	0.29	40.49	0.175	64.0	370	5.55
Boiler 4	2	Cell	12/06/02	64,342	--	118,594	233.18	32.39	67.62	0.29	36.97	0.159	58.0	357	5.63
Boiler 4	3	Cell	12/06/02	64,772	--	119,908	234.83	32.62	68.10	0.29	35.10	0.149	58.0	357	5.68
Boiler 4	1	Cell	11/12/03	66,441	--	115,701	223.27	31.01	64.75	0.29	22.70	0.102		345	4.20
Boiler 4	2	Cell	11/12/03	61,499	--	123,123	239.17	33.22	69.36	0.29	26.21	0.110	65.0	355	4.22
Boiler 4	3	Cell	11/12/03	65,967	--	125,194	242.28	33.65	70.26	0.29	23.58	0.097	65.0	350	4.30
Boiler 4	1	Cell	11/12/04	65,880	106,776	113,552	227.04	31.53	65.84	0.29	45.67	0.201	72.0	370	5.94
Boiler 4	2	Cell	11/12/04	68,565	106,433	115,521	231.39	32.14	67.10	0.29	42.66	0.184	78.0	370	6.24
Boiler 4	3	Cell	11/12/04	64,196	100,802	117,662	235.76	32.74	68.37	0.29	38.27	0.162	70.0	370	6.02

Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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)		Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			
Boiler 5	1	Traveling Grate	02/15/93	37,861	--	114,200	215.6	29.94	32.34	0.15	30.09	0.140			
Boiler 5	2	Traveling Grate	02/15/93	32,693	--	104,600	198.1	27.51	29.72	0.15	26.50	0.134			
Boiler 5	1	Traveling Grate	11/17/93	53,499	--	116,250	229.1	31.82	34.37	0.15	--	--			
Boiler 5	2	Traveling Grate	11/17/93	47,026	--	114,000	224.7	31.21	33.70	0.15	--	--			
Boiler 5	3	Traveling Grate	11/17/93	45,963	--	109,672	216.1	30.01	32.41	0.15	--	--			
Boiler 5	1	Traveling Grate	11/18/93	44,173	--	115,105	220.5	30.63	33.08	0.15	--	--			
Boiler 5	2	Traveling Grate	11/18/93	47,866	--	116,301	223.0	30.97	33.45	0.15	--	--			
Boiler 5	3	Traveling Grate	11/18/93	46,525	--	117,176	216.1	30.01	32.41	0.15	--	--			
Boiler 5	1	Traveling Grate	12/16/93	46,388	--	116,800	215.8	29.97	32.37	0.15	--	--			
Boiler 5	2	Traveling Grate	12/16/93	47,571	--	117,100	215.7	29.96	32.36	0.15	--	--			
Boiler 5	3	Traveling Grate	12/16/93	41,873	--	116,000	214.2	29.75	32.13	0.15	--	--			
Boiler 5	1	Traveling Grate	01/26/95	51,140	--	120,444	226.9	31.52	34.04	0.15	27.68	0.122			
Boiler 5	2	Traveling Grate	01/26/95	58,552	--	112,075	211.2	29.33	31.68	0.15	31.19	0.148			
Boiler 5	3	Traveling Grate	01/26/95	59,351	--	115,846	217.7	30.24	32.66	0.15	30.92	0.142			
Boiler 5	4	Traveling Grate	01/26/95	49,664	--	95,695	180.4	25.05	27.06	0.15	25.66	0.142			
Boiler 5	1	Traveling Grate	01/27/95	61,736	--	99,346	186.9	25.95	28.03	0.15	25.84	0.138			
Boiler 5	2	Traveling Grate	01/27/95	56,838	--	112,500	211.9	29.43	31.78	0.15	33.60	0.159			
Boiler 5	3	Traveling Grate	01/27/95	39,890	--	96,947	176.3	24.48	26.44	0.15	23.52	0.133			
Boiler 5	1	Traveling Grate	12/06/95	53,750	--	126,800	242.5	33.68	36.38	0.15	--	--			
Boiler 5	2	Traveling Grate	12/06/95	54,353	--	123,600	235.9	32.76	35.39	0.15	--	--			
Boiler 5	3	Traveling Grate	12/06/95	54,301	--	122,900	234.3	32.54	35.15	0.15	--	--			
Boiler 5	4	Traveling Grate	12/06/95	52,963	--	122,160	232.9	32.35	34.94	0.15	28.97	0.124			
Boiler 5	5	Traveling Grate	12/06/95	55,652	--	117,300	223.7	31.07	33.56	0.15	24.79	0.111			
Boiler 5	6	Traveling Grate	12/06/95	53,670	--	126,800	242.5	33.68	36.38	0.15	24.25	0.100			
Boiler 5	1	Traveling Grate	01/08/97	40,227	--	124,300	237.9	33.04	35.69	0.15	20.10	0.084			
Boiler 5	2	Traveling Grate	01/08/97	44,210	--	125,300	239.8	33.31	35.97	0.15	22.60	0.093			
Boiler 5	3	Traveling Grate	01/08/97	44,167	--	126,500	242.1	33.63	36.32	0.15	21.80	0.093			
Boiler 5	1	Traveling Grate	01/13/98	56,327	--	122,200	237.1	35.60	35.57	0.15	29.20	0.123			
Boiler 5	2	Traveling Grate	01/13/98	54,988	--	124,000	240.1	36.00	36.02	0.15	28.10	0.117			
Boiler 5	3	Traveling Grate	01/13/98	55,018	--	122,900	237.9	35.70	35.69	0.15	27.30	0.115			
Boiler 5	1	Traveling Grate	12/04/98	45,469	--	119,500	219.3	32.90	32.90	0.15	31.40	0.143			
Boiler 5	2	Traveling Grate	12/04/98	47,496	--	117,500	219.0	32.90	32.85	0.15	21.40	0.096			
Boiler 5	3	Traveling Grate	12/04/98	48,859	--	120,300	222.4	33.40	33.36	0.15	23.60	0.105			
Boiler 5	1	Traveling Grate	01/11/00	49,771	--	120,686	223.2	31.00	33.48	0.15	24.17	0.108	ND	1050	11.00
Boiler 5	2	Traveling Grate	01/11/00	48,402	--	122,229	225.9	31.38	33.89	0.15	21.46	0.095	ND	1050	11.00
Boiler 5	3	Traveling Grate	01/11/00	50,598	--	123,257	227.8	31.64	34.17	0.15	21.96	0.096	ND	1050	11.00
Boiler 5	1	Traveling Grate	12/07/00	51,369	76,503	120,200	224.7	31.21	33.71	0.15	30.30	0.135	ND	1060	8.40
Boiler 5	2	Traveling Grate	12/07/00	52,013	78,219	122,900	229.7	31.90	34.46	0.15	26.40	0.115	ND	1060	8.30
Boiler 5	3	Traveling Grate	12/07/00	53,498	78,449	123,900	231.5	32.15	34.73	0.15	25.30	0.109	ND	1060	8.30
Boiler 5	1	Traveling Grate	12/11/01	51,580	77,907	123,680	231.2	32.11	34.68	0.15	27.18	0.118	ND	1190	8.30
Boiler 5	2	Traveling Grate	12/11/01	50,910	77,421	128,080	239.3	33.24	35.90	0.15	16.95	0.071	ND	1190	8.19
Boiler 5	3	Traveling Grate	12/11/01	50,965	78,274	128,240	239.6	33.28	35.94	0.15	25.37	0.106	ND	1190	8.50
Boiler 5	1	Traveling Grate	12/17/01	61,608	--	122,727	233.3	32.41	35.00	0.15	25.13	0.108		1080	8.70
Boiler 5	2	Traveling Grate	12/17/01	59,583	--	125,813	239.3	33.24	35.90	0.15	23.24	0.097		1080	8.70
Boiler 5	3	Traveling Grate	12/17/01	60,034	--	130,125	247.5	34.38	37.13	0.15	24.85	0.100		1040	8.90

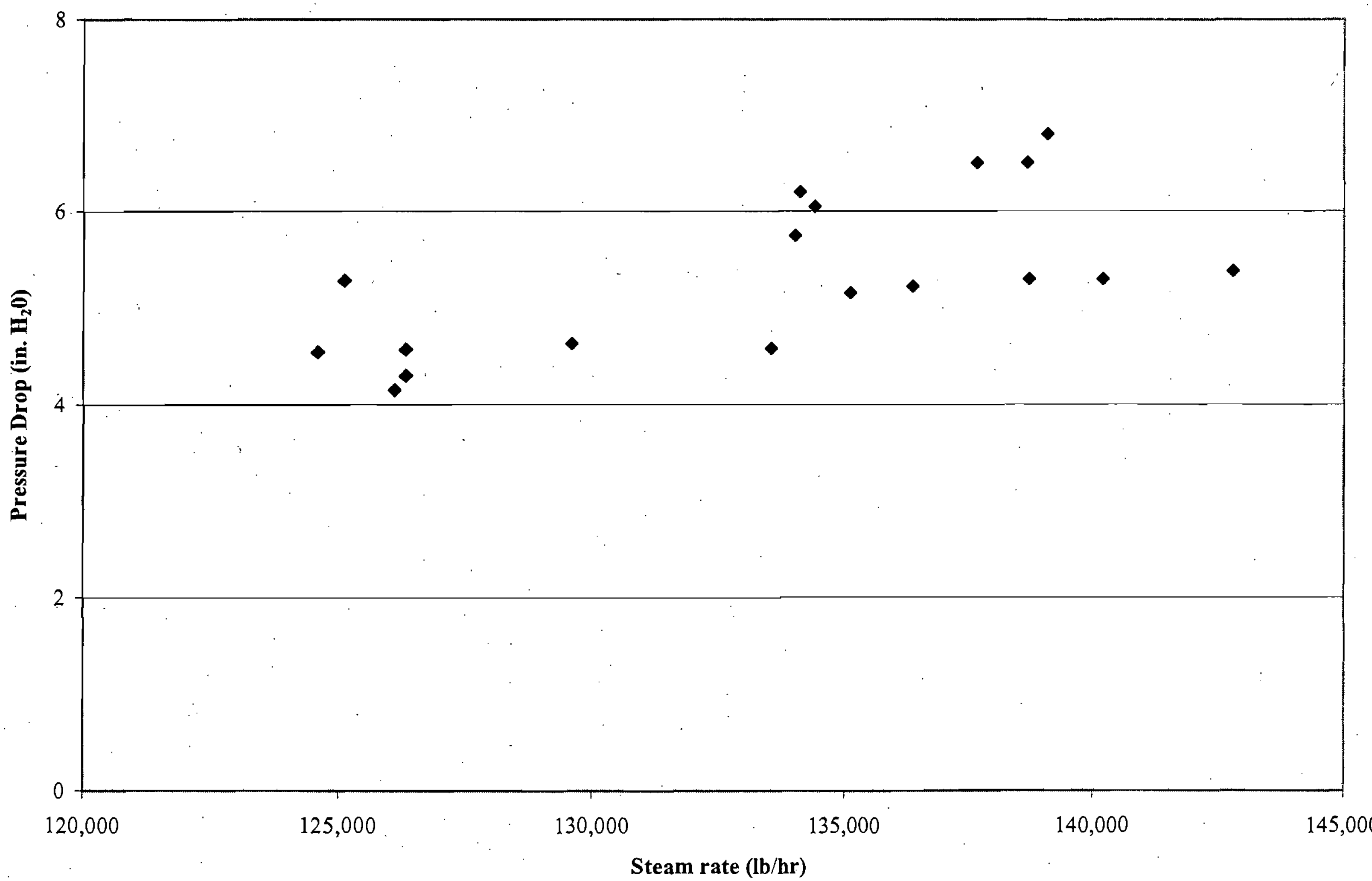
Table B-1. Boiler PM Emission Tests, Atlantic Sugar Association

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)		Average Liquid Pressure (psig)	Total Average Water Flow (gpm)	Average Pressure Drop (in. H_2O)
									lb/hr	lb/MMBtu	lb/hr	lb/MMBtu			
Boiler 5	4	Traveling Grate	12/17/01	59,026	--	130,875	248.9	34.57	37.34	0.15	23.60	0.095		1030	8.80
Boiler 5	1	Traveling Grate	12/18/01	59,625	--	121,200	230.0	31.94	34.50	0.15	23.64	0.103		1040	8.80
Boiler 5	1	Traveling Grate	12/19/01	60,820	--	117,600	223.7	31.07	33.56	0.15	24.79	0.111		1120	8.25
Boiler 5	2	Traveling Grate	12/19/01	62,175	--	113,250	215.4	29.92	32.31	0.15	25.46	0.118		1160	8.70
Boiler 5	3	Traveling Grate	12/19/01	61,483	--	112,800	214.6	29.80	32.19	0.15	24.42	0.114		1180	8.80
Boiler 5	1	Traveling Grate	12/20/01	64,146	--	107,250	203.7	28.29	30.55	0.15	20.69	0.102		1100	9.00
Boiler 5	2	Traveling Grate	12/20/01	60,164	--	123,469	234.3	32.54	35.15	0.15	22.56	0.096		1090	9.00
Boiler 5	3	Traveling Grate	12/20/01	56,354	--	125,905	239.5	33.26	35.92	0.15	27.38	0.114		1110	8.90
Boiler 5	4	Traveling Grate	12/20/01	57,647	--	127,219	241.9	33.60	36.29	0.15	28.40	0.117		1120	9.75
Boiler 5	1	Traveling Grate	12/19/02	55,258	85,871	116,200	219.7	30.51	32.96	0.15	22.42	0.102	ND	1000	3.09
Boiler 5	2	Traveling Grate	12/19/02	57,026	85,257	120,300	228.1	31.68	34.22	0.15	24.65	0.108	ND	1000	2.93
Boiler 5	3	Traveling Grate	12/19/02	53,883	82,783	122,000	231.7	32.18	34.76	0.15	24.11	0.104	ND	1000	2.82
Boiler 5	1	Traveling Grate	12/09/03	47,074	72,431	120,185	222.1	30.85	33.32	0.15	21.36	0.096	70/73	955	10.60
Boiler 5	2	Traveling Grate	12/09/03	46,698	70,553	120,800	223.2	31.00	33.48	0.15	23.73	0.109	70/72	935	10.30
Boiler 5	3	Traveling Grate	12/09/03	46,232	71,191	117,771	217.3	30.18	32.60	0.15	25.64	0.115	69/71	920	10.30
Boiler 5	1	Traveling Grate	12/07/04	48,707	75,551	126,462	240.3	31.75	34.29	0.15	30.56	0.127	71.7	1014	7.7
Boiler 5	2	Traveling Grate	12/07/04	48,294	77,362	127,569	242.8	33.86	36.57	0.15	33.05	0.136	72.0	972	7.7
Boiler 5	3	Traveling Grate	12/07/04	48,707	75,551	125,908	239.5	33.69	36.39	0.15	29.96	0.125	71.3	958	7.5

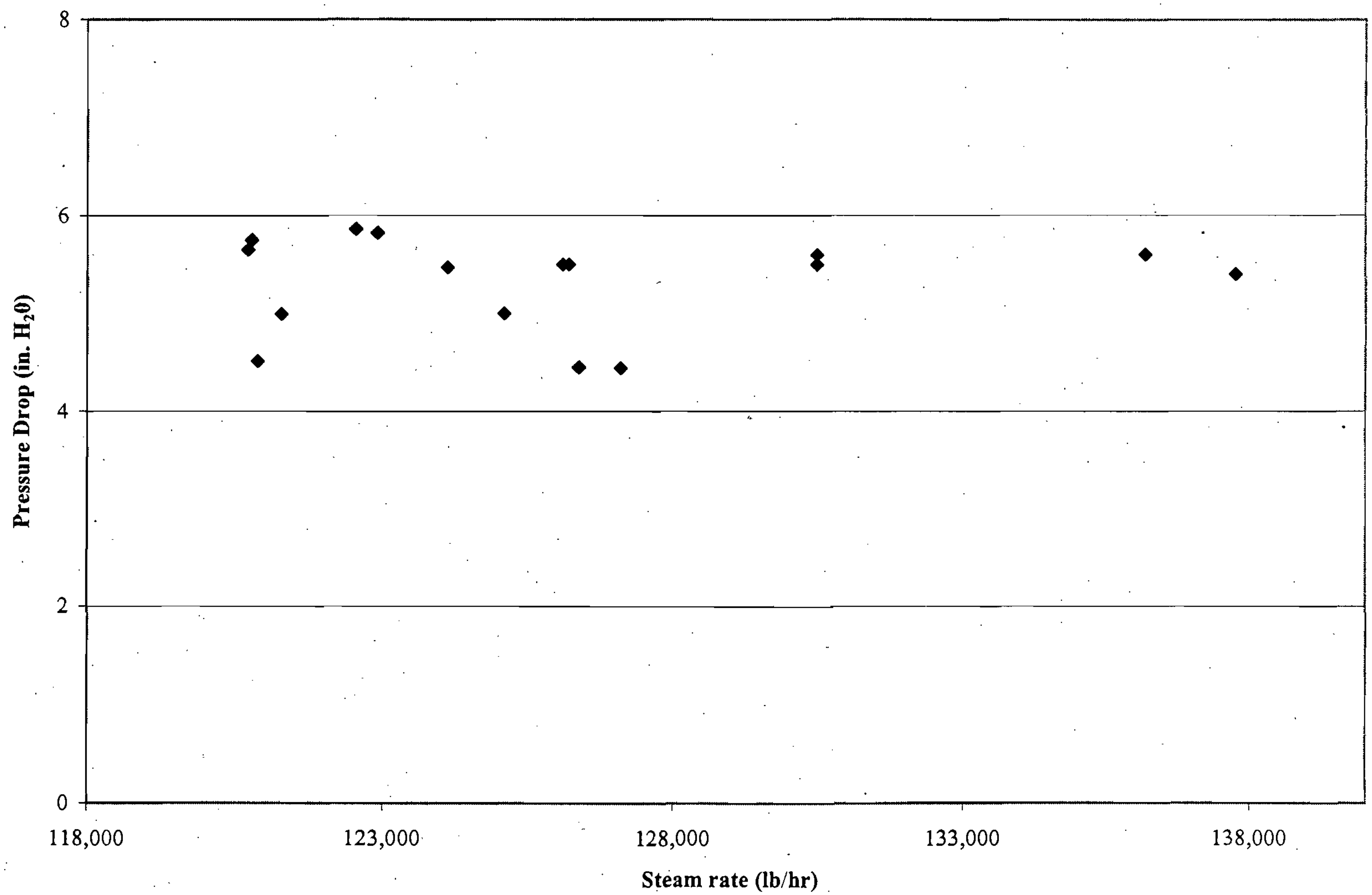
Notes:
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
TPH = tons per hour.
ND = No Data

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

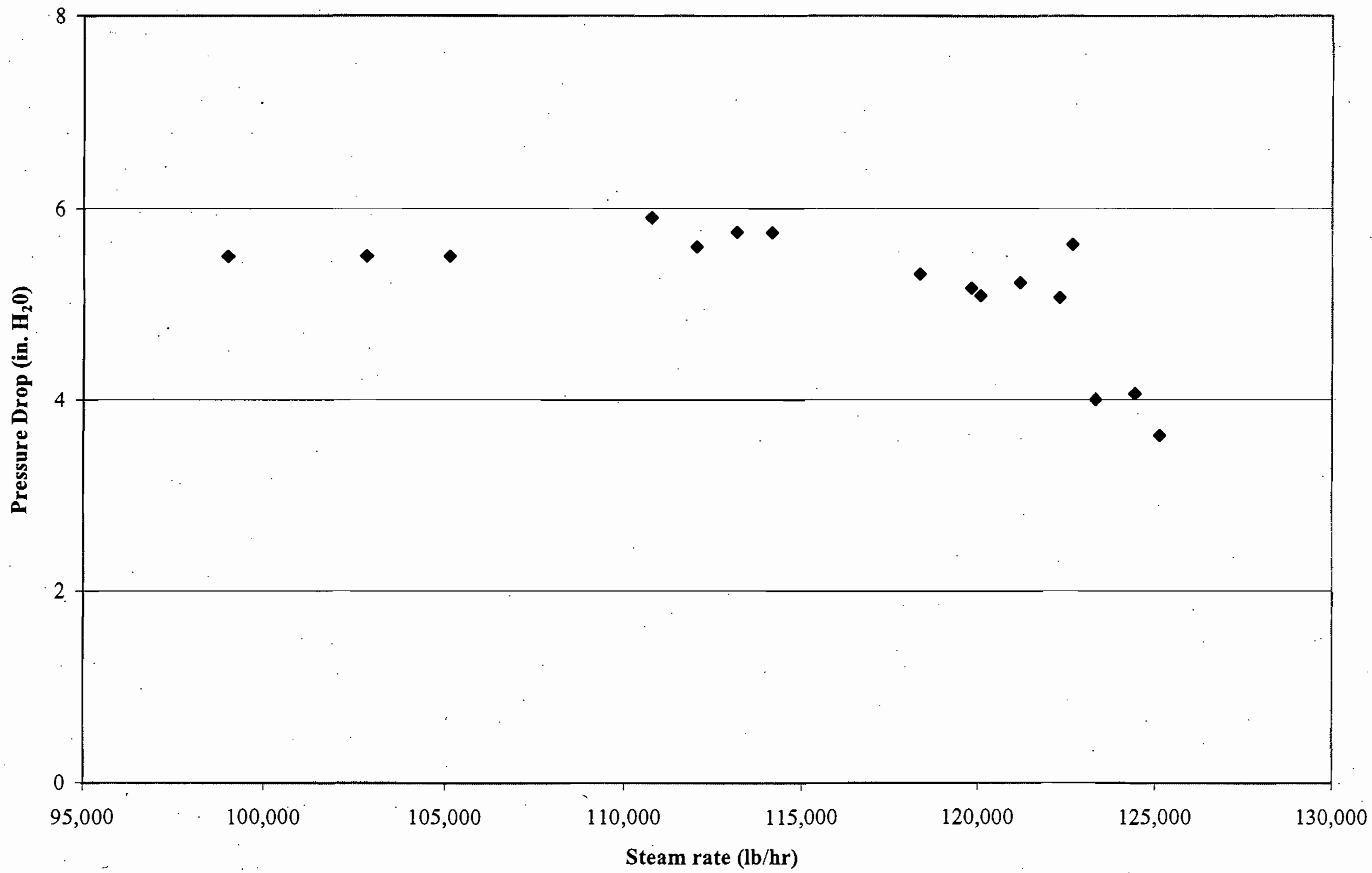
ASA Boiler No. 1
Pressure Drop vs. Steam Rate



ASA Boiler No. 2
Pressure Drop vs. Steam Rate



ASA Boiler No. 3
Pressure Drop vs. Steam Rate



ASA Boiler No. 4
Pressure Drop vs. Steam Rate