State: April 27, 1981
Federal: May 7, 1981

BOILER NO. 8 AT SUGAR CANE GROWERS COOPERATIVE

PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION REPORT

Prepared for:

SUGAR CANE GROWERS COOPERATIVE
Belle Glade, Florida

Prepared by:

ENVIRONMENTAL SCIENCE AND ENGINEERING, INC.
Gainesville, Florida

April 1981

ESE No. 80-190-100

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APPLICATION TO CONSTRUCT AIR POLLUTION SOURCES

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Carbonaceous fuel boiler [x] New[1] [ ] Existing[1]

APPLICATION TYPE: [x] Construction [ ] Operation [ ] Modification

COMPANY NAME: Sugar Cane Growers Cooperative of Florida COUNTY: Palm Beach

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peeking Unit No. 2, Gas Fired) Boiler 8 with impingement scrubbers

SOURCE LOCATION: Street 1/2 mile north of Airport Road City Belle Glade

UTM: East 534.9 North 2953.3

Latitude 26 ° 42 ' 30 "N Longitude 80 ° 39 ' 00 "W

APPLICANT NAME AND TITLE: Enrique R. Arias, Executive Vice President

APPLICANT ADDRESS: Post Office Box 666, Belle Glade, Florida 33430

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Sugar Cane Growers Cooperative of Florida

I certify that the statements made in this application for a construction permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Enrique R. Arias

Enrique R. Arias, Executive Vice President
Name and Title (Please Type)

Date: 4/24/81 Telephone No. (305) 996-5556

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed: David A. Buff

David A. Buff
Name (Please Type)

(Affix Seal)

Environmental Science and Engineering, Inc.
Company Name (Please Type)

P.O. Box ESE, Gainesville, FL 32601
Mailing Address (Please Type)

Florida Registration No. 19011 Date: 4-23-81 Telephone No. (904) 372-3318

[1]See Section 17-2.02(15) and (22), Florida Administrative Code, (F.A.C.)

BEST AVAILABLE COPY

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Addition of 240,000-lb/hr rated steam capacity boiler capable of burning bagasse, bagasse residue, and oil. Modification of existing plant along with new source will result in net air quality improvement and full compliance (see Project description Section 1.0 of PSD report).

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction July 1981 Completion of Construction November 1982

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Scrubber system for new boiler (including ducts, fans, ports, etc.): $1.1 to 1.6 million

Boiler No.4 stack modification: $200,000.

Boilers No.6 and No.7 stack modification: $175,000.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

NA - New emission point

E. Is this application associated with or part of a Development of Regional Impact (DRI) pursuant to Chapter 380, Florida Statutes, and Chapter 22F-2, Florida Administrative Code? ____ Yes x No

F. Normal equipment operating time: hrs/day 24 ; days/wk 5 ; wks/yr 39 ; if power plant, hrs/yr ____ ; if seasonal, describe: Source operates during crop season, generally November through March. May also operate on occasion during off season (October, April, May, and June).

G. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? Yes, ozone
   a. If yes, has "offset" been applied? NA
   b. If yes, has "Lowest Achievable Emission Rate" been applied? NA
   c. If yes, list non-attainment pollutants. Ozone
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes
3. Does the State "Prevention of Significant Deteriorlation" (PSD) requirements apply to this source? If yes, see Sections VI and VII. Yes
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? No
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
Not applicable				

Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): Not Applicable
2. Product Weight (lbs/hr): 240,000-lb steam/hr rated capacity
264,000-lb steam/hr peak capacity

Airborne Contaminants Emitted:

Name of Contaminant	Emission[1]		Allowed Emission[2] Rate per Ch. 17-2, F.A.C.	Allowable[3] Emission lbs/hr	Potential Emission[4]		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
Particulate	100.8	324.5	0.2 lb/MM Btu, 17-2.05 (6)	100.8	1,121.4	4,091	A
Sulfur Dioxide	343.5	799.7	NA	NA	387.9	1,415	A
Nitrogen Oxides	129.2	259.4	NA	NA	129.2	471.4	A
ydrocarbons	1.8	0.2	NA	NA	1.8	6.6	A
arbon Monoxide	8.8	1.2	NA	NA	8.8	32.1	A

Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles[5] Size Collected (in microns)	Basis for Efficiency (Sec. V, It[5]
oy Turbulaire Type D	Particulate	+90%	See Attachment B	manufacturer's literature
Impingement Scrubber, or				
equivalent	SO_2	40%	NA	Test data
				see Attachment C

ee Section V, Item 2.

leference applicable emission standards and units (e.g., Section 17-2.05(6) Table II, E. (1), F.A.C. — 0.1 pounds per million BTU eat input)

alculated from operating rate and applicable standard

mission, if source operated without control (See Section V, Item 3)

f Applicable

Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
agasse	15,000 lb (dry)	63,000 lb (dry)*	504.0
esidue	36,600 lb (dry)	49,834 lb (dry)*	443.5
o.6 Fuel Oil	1.5 bbls	42 bbls*	250.0

*Max when fired singly, not in combination with other fuels

Inits Natural Gas, MMCF/hr; Fuel Oils, barrels/hr; Coal, lbs/hr

el Analysis: See Attachment A

rcent Sulfur: ______ Percent Ash: ______

nsity: ______ lbs/gal Typical Percent Nitrogen: ______

at Capacity: ______ BTU/lb ______ BTU/gal

her Fuel Contaminants (which may cause air pollution): ______

If applicable, indicate the percent of fuel used for space heating. Annual Average NA Maximum NA

Indicate liquid or solid wastes generated and method of disposal.

Liquid and solid wastes generated from scrubbers will be routed to settling pond.

Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 155 ft. Stack Diameter: 10.0 ft.

Gas Flow Rate: 170,000 ACFM Gas Exit Temperature: 160 °F.

Water Vapor Content: 29 % Velocity: 36 FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq & Gas By-prod.)	Type VI (Solid By-prod.)
bs/hr icinerated							

scription of Waste ______

tal Weight Incinerated (lbs/hr) ______ Design Capacity (lbs/hr) ______

proximate Number of Hours of Operation per day ______ days/week ______

nufacturer ______

te Constructed ______ Model No. ______

	Volume (ft)^3	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
rimary Chamber					
econdary Chamber					

ıck Height: ______________ ft. Stack Diameter ______________ Stack Temp. ______________

ıs Flow Rate: ______________ ACFM ______________ DSCFM* Velocity ______________ FPS

f 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

pe of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner [ ] Other (specify) ______________

ief description of operating characteristics of control devices: ______________

timate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

SECTION V: SUPPLEMENTAL REQUIREMENTS

ıase provide the following supplements where required for this application.

. Total process input rate and product weight — show derivation.
See Attachment A and PSD report
. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.,) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
See Attachment A and PSD Report
Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
See Attachment A and PSD Report
. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, etc.).
See BACT discussion, Attachments B and D
. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3, and 5 should be consistent: actual emissions = potential (1-efficiency).
See BACT discussion, Attachments B and D
. An 8½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
See PSD Report
. An 8½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).
See PSD Report
. An 8½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
See PSD Report

An application fee of $20, unless exempted by Section 17-4.05(3), F.A.C. The check should be made payable to the Department of Environmental Regulation.

With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?
[ ] Yes [x] No

Contaminant	Rate or Concentration

Has EPA declared the best available control technology for this class of sources (If yes, attach copy) [ ] Yes [X] No
See Note below*

Contaminant	Rate or Concentration
Particulate	0.15 #/MMBtu from carbonaceous fuel
Particulate	0.1 #/MMBtu from fossil fuel
SO_2	0.8 #/MMBtu from fossil fuel
Visible Emissions	30% except 40% up to 2 minutes/hour

What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
Particulate	0.20 lb/MMBtu from carbonaceous fuel
Particulate	0.10 lb/MMBtu from fossil fuel
SO_2	0.15 lb/MM Btu (bag.), 0.54lb/MM Btu (bag. res.), 2.1 lb/MM Btu (oil)
NO_x, CO, HC	Good firing practices and operation
Visible Emissions	30 % except 40% up to 2 minutes/hour

Describe the existing control and treatment technology (if any).

1. Particulate Control Device/System: Joy Turbulaire Type D Impingement Scrubber.
2. Operating Principles: Impaction of large particles on water droplets, removal of small particles by venturi effect, inertial separation of droplets from gas stream by use of swirl vanes.
3. Efficiency:* Approximately 91%
4. Capital Costs:
5. Useful Life: 5 to 10 years
6. Operating Costs: See Attachment D
7. Energy: 500 KW
8. Maintenance Cost:
9. Emissions:

Contaminant	Rate or Concentration
Particulate	0.23 lb/MMBtu maximum at this site (SCGC)

xplain method of determining D 3 above.

Based on AP-42 estimates and allowable emission rates of 0.2 lb/MM Btu.

*Note: The BACT determination was made by Florida DER for a bagasse boiler at a specific site (not at SCGC) with different fuel characteristics. Determination is attached. No BACT determination has been made for a combination bagasse-/bagasse residue-fired boiler.

10. Stack Parameters

a. Height: 85 ft. b. Diameter: 3 @ 5 ft 4 in ft.

c. Flow Rate: 149,000 total ACFM d. Temperature: 160 °F

e. Velocity: 37 FPS

Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1. Particulate

a. Control Device: Electrostatic Precipitator

b. Operating Principles: Particle charging by high voltage corona. Particles collected by migration to oppositely-charged electrode.

c. Efficiency*: +91%

d. Capital Cost:

e. Useful Life: 5-10 years

f. Operating Cost: See Attachment D

g. Energy*: 167 KW

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:
Availability of construction materials is good. No process chemicals required.

j. Applicability to manufacturing processes: Has never been applied to bagasse- or bagasse residue-fired boilers. Possible fire hazard and explosion potential.

k. Ability to construct with control device, install in available space, and operate within proposed levels:
Ability to construct and install is good. Operation within proposed levels has not been demonstrated.

2. Particulate

a. Control Device: Fabric Filter (baghouse)

b. Operating Principles: Particulates entrained on fibrous bags forming filter cakes. Cake periodically removed by mechanical shakers.

c. Efficiency*: +91%

d. Capital Cost:

e. Useful Life: 15 to 20 years

f. Operating Cost: See Attachment D

g. Energy**: 350 KWH

h. Maintenance Costs:

i. Availability of construction materials and process chemicals:
Available

j. Applicability to manufacturing processes: Not good--subject to fire hazard. Has not been demonstrated on bagasse boilers.

k. Ability to construct with control device, install in available space, and operate within proposed levels:
Requires more space than a scrubber. Will meet the required limitations if installed. However, emission levels have not been demonstrated for this application.

*Explain method of determining efficiency.
Literature sources

**Energy to be reported in units of electrical power — KWH design rate.

3. Particulate

a. Control Device: Venturi Scrubber

b. Operating Principles: Particulates removed by impaction on water droplets sprayed perpendicular to gas stream at venturi throat

c. Efficiency*: +91%

d. Capital Cost:

e. Life: 5 to 10 years

f. Operating Cost: See Attachment D

g. Energy: 1,150 KW

h. Maintenance Cost:

*Explain method of determining efficiency above.
Current literature.

i. Availability of construction materials and process chemicals:

Available

j. Applicability to manufacturing processes: Currently used in the Sugar Industry. However, are subject to plugging without initial particle removal devices.

k. Ability to construct with control device, install in available space and operate within proposed levels: Able to be constructed within space limitations and will attain required particulate emission levels.

4. Particulate

a. Control Device
Joy Turbulaire Type D Impingement Scrubber

b. Operating Principles: Impaction of large particulates on water droplets, removal of small particles by venturi effect; initial separation of droplets from gas stream by use of swirl vanes.

c. Efficiency*: 91%

d. Capital Cost:

e. Life: 5-10 year

f. Operating Cost: See Attachment D

g. Energy: 500 KW

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

Readily available

j. Applicability to manufacturing processes: Excellent. Type D impingement separators are widely used in the sugar industry.

k. Ability to construct with control device, install in available space, and operate within proposed levels:
Excellent

Describe the control technology selected: Particulate

1. Control Device: Joy Turbulaire Type D Impingement Scrubber

2. Efficiency*: 91%

3. Capital Cost:

4. Life: 5-10 year

5. Operating Cost: See Attachment D

6. Energy: 500 KW

7. Maintenance Cost:

8. Manufacturer: Joy Industrial Equipment Company

9. Other locations where employed on similar processes:

a.

(1) Company: Osceola Farms Company

(2) Mailing Address: P.O. Box 679

(3) City: Pahokee

(4) State: Florida 33476

(5) Environmental Manager: Mr. Alberto Recio

(6) Telephone No.: (305) 924-7156

Explain method of determining efficiency above.
Current literature.

(7) Emissions*:

Contaminant	Rate or Concentration
Particulate (Avg. all boilers) 1975-1976	0.193 $lb/10^6$ Btu
Particulate (Avg. all boilers) 1976-1977	0.265 $lb/10^6$ Btu
Particulate (Avg. all boilers) 1977-1978	0.177 $lb/10^6$ Btu
Particulate (Avg. all boilers) 1978-1979	0.283 $lb/10^6$ Btu

(8) Process Rate*:
300,000 lb steam/hour

b.

(1) Company:
U.S. Sugar (Clewiston)

(2) Mailing Address:
P.O. Box 1206

(3) City:
Clewiston

(4) State: Florida 33440

*Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

(5) Environmental Manager: Mr. A.R. Mayo

(6) Telephone No.: (813) 983-8121

(7) Emissions*:

Contaminant	Rate or Concentration
Particulate (Avg. 3 boilers) 1975-1976	0.166 lb/MMBtu
Particulate (Avg. 4 boilers) 1976-1977	0.192 lb/MMBtu
Particulate (Avg. 5 boilers) 1977-1978	0.188 lb/MMBtu
Particulate (Avg. 4 boilers) 1978-1979	0.193 lb/MMBtu
Particulate (Avg. 5 boilers) 1979-1980	0.24 lb/MMBtu

(8) Process Rate*:
335,000 to 600,000 steam/hour

10. Reason for selection and description of systems:

See BACT Attachment

pplicant must provide this information when available. Should this information not be available, applicant must state the reason(s) hy.

. Describe the existing control and treatment technology (if any).

1. Control Device/System: Sulfur Dioxide: No specific SO_2 removal systems currently are in use on bagasse- or bagasse residue-fired boilers.

2. Operating Principles:

3. Efficiency: *

4. Capital Costs:

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

Explain method of determining D 3 above.

Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1. Sulfur Dioxide

a. Control Device: Joy Turbulaire Impingement Scrubber

b. Operating Principles: See particulate removal systems discussion.

c. Efficiency*: +40%

d. Capital Cost:

e. Useful Life: 5-10 years

f. Operating Cost: See Attachment D

g. Energy*: 500 KW

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:
Requires no additional materials or chemicals beyond that required for particulate removal system.

j. Applicability to manufacturing processes:
Excellent.

k. Ability to construct with control device, install in available space, and operate within proposed levels:
Excellent.

2. Sulfur Dioxide

a. Control Device: Lime/limestone scrubbing

b. Operating Principles: Wet scrubbing with lime/limestone slurry. Waste disposal to settling pond, water recycle. SO_2 is absorbed by aqueous solution.

c. Efficiency*: +90%

d. Capital Cost:

e. Useful Life: 5-10 years

f. Operating Cost: See Attachment D

g. Energy**: 2,000 KW

h. Maintenance Costs:

i. Availability of construction materials and process chemicals:
Assumed to be good.

j. Applicability to manufacturing processes:
Has been applied to similar processes (i.e., coal boilers).

k. Ability to construct with control device, install in available space, and operate within proposed levels:
Assumed satisfactory. Requires large land area for waste disposal.

*Explain method of determining efficiency.

*Energy to be reported in units of electrical power — KWH design rate.

3. Sulfur Dioxide

a. Control Device: Sodium Throwaway Scrubbing

b. Operating Principles: Wet scrubbing with aqueous solution. SO_2 is absorbed by solution. Requires sludge disposal, water treatment, and solution preparation.

c. Efficiency*: +90%

d. Capital Cost:

e. Life: 5-10 years

f. Operating Cost: See Attachment D

g. Energy: 1,000 KW

h. Maintenance Cost:

*Explain method of determining efficiency above.

i. Availability of construction materials and process chemicals:

Assumed adequate.

j. Applicability to manufacturing processes: Has been applied to other boiler types (i.e., coal).

k. Ability to construct with control device, install in available space and operate within proposed levels:

Assumed adequate.

4. Sulfur Dioxide

a. Control Device

Double alkali scrubbing

b. Operating Principles: Wet scrubbing with aqueous alkaline solution. SO_2 is absorbed by the solution. Requires sludge disposal, water treatment, and solution preparation. Regeneration of solution by calcium alkali.

c. Efficiency*: +90%

d. Capital Cost:

e. Life: 5-10 years

f. Operating Cost: ee Attachment D

g. Energy: 800 KW

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

Assumed good.

j. Applicability to manufacturing processes: Has been applied to other boiler types (i.e., coal).

k. Ability to construct with control device, install in available space, and operate within proposed levels:

Assumed adequate, but possible limitations due to waste disposal requirements.

Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

5. k Sulfur Dioxide

a. Control Device: Spray drying

b. Operating Principles: Spray of aqueous lime or soda ash absorbent introduced in tower, where it absorbs SO_2 and is dried to solid form. Dry collection then takes place (i.e., fabric filter).

c. Efficiency*: +90%

d. Capital Cost:

e. Useful Life: 5-10 years

f. Operating Cost: See Attachment D

g. Energy*: 1,000 KW

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

Assumed good.

j. Applicability to manufacturing processes: Generally applicable, high reliability claimed but undemonstrated.

k. Ability to construct with control device, install in available space, and operate within proposed levels:

Large land requirements for solid waste disposal.

6. X Sulfur Dioxide

a. Control Device: Wellman-Lord process

b. Operating Principles: Wet scrubbing using a sodium sulfite solution. Regeneration is included. SO_2 is produced and converted to other products.

c. Efficiency*: +90%

d. Capital Cost:

e. Useful Life: 5-10 years

f. Operating Cost: See Attachment D

g. Energy**: 6,000 KW

h. Maintenance Costs:

i. Availability of construction materials and process chemicals:

Assumed good.

j. Applicability to manufacturing processes: Costs and complexity will limit to small boilers. Good reliability on coal boilers.

k. Ability to construct with control device, install in available space, and operate within proposed levels:

Assumed adequate, but undemonstrated.

*Explain method of determining efficiency.

*Energy to be reported in units of electrical power — KWH design rate.

F. *Describe the control technology selected:*

1. Control Device: Sulfur Dioxide

   Joy Turbulaire Impingement Scrubber

2. Efficiency*: +40%
3. Capital Cost:
4. Life: 5-10 years
5. Operating Cost: No incremental cost above particulate control system.
6. Energy: 500 KW
7. Maintenance Cost:
8. Manufacturer:
9. Other locations where employed on similar processes:

   a. See particulate removal systems discussion and Attachment C.

      (1) Company:

      (2) Mailing Address:

      (3) City: (4) State:

      (5) Environmental Manager:

      (6) Telephone No.:

*Explain method of determining efficiency above.

      (7) Emissions*:

Contaminant	Rate or Concentration

      (8) Process Rate*:

   b.

      (1) Company:

      (2) Mailing Address:

      (3) City: (4) State:

*Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions*:

Contaminant	Rate or Concentration

(8) Process Rate*:

10. Reason for selection and description of systems:

See Attachment D

*Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII – PREVENTION OF SIGNIFICANT DETERIORATION

Company Monitored Data Florida Sugar Cane League

1. 10 no sites 10 TSP 1 (C) SO_2* ______ Wind spd/dir

Period of monitoring TSP: 1 / 1 / 80 (month day year) to 12 / 31 / 80 (month day year) SO_2: 1/1/78 to 6/30/79

Other data recorded Palm Beach County TSP and SO_2

Attach all data or statistical summaries to this application. See PSD report

2. Instrumentation, Field and Laboratory Florida Sugar Cane League TSP data.
   a) Was instrumentation EPA referenced or its equivalent? X Yes ___ No
   b) Was instrumentation calibrated in accordance with Department procedures? X Yes ___ No ___ Unknown

Meteorological Data Used for Air Quality Modeling

1. 5 Year(s) of data from 01 / 01 / 70 (month day year) to 12 / 31 / 74 (month day year)
2. Surface data obtained from (location) West Palm Beach
3. Upper air (mixing height) data obtained from (location) Miami
4. Stability wind rose (STAR) data obtained from (location) NA

Computer Models Used

1. ISC modified to process 5 years Modified? If yes, attach description.
2. of data and provide composite tables. Modified? If yes, attach description.
3. ______ Modified? If yes, attach description.
4. ______ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate
TSP	(See Section III.C &PSD report) grams/sec
SO^2	(See Section III.C &PSD report) grams/sec

Emission Data Used in Modeling See PSD Report

Attach list of emission sources. Emission data required is source name, description on point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

Attach all other information supportive to the PSD review.
See PSD Report

*Specify bubbler (B) or continuous (C).

Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.

Positive social impacts are expected with increased sugar production, due to increased employment and increased tax base for the area. The chosen technology makes these benefits possible. The environmental impacts are discussed in the PSD report.

Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.

See attachments

ATTACHMENT A

PROPOSED BOILER NO. 8
EMISSION ESTIMATES

FUEL USAGE CALCULATIONS

Peak Steam Capacity = 264,000 lb/hr
Btu requirements per lb steam = 1,050 Btu/lb

Boiler efficiencies:	Bagasse	- 55%
	Residue	- 62.5%
	Oil	- 80%
System SO_2 loss:	Bagasse	- 40%
	Residue	- 40%
	Oil	- 0%

Fuel Analysis:

	Bagasse	Residue	No. 6 Fuel Oil
Btu/lb	8,000 (dry)	8,900 (dry)	17,500
lbs/gal	—	—	8.1
% S	0.1 (dry)	0.4 (dry)	1.0
% N	0.3 (dry)	0.4 (dry)	0
% Ash	0.5-0.3 (dry)	1.9-3.8 (dry)	0.1
% H_2O	55	40	0.2

Bagasse Burning: 264,000 lb/hr steam x 1,050 Btu/lb ÷ 0.55 = 504.0 x 10^6 Btu/hr
504.0 x 10^6 Btu/hr ÷ 8,000 Btu/lb = 63,000 lb/hr dry bagasse

Residue Burning: 264,000 lb/hr steam x 1,050 Btu/lb ÷ 0.625 = 443.5 x 10^6 Btu/hr
443.5 x 10^6 Btu/hr ÷ 8,900 Btu/lb = 49,834 lb/hr dry residue

Oil Burning: Limited to 250 x 10^6 Btu/hr heat input
250 x 10^6 Btu/hr ÷ 17,500 Btu/lb = 14,286 lb/hr = 1,764 gal/hr

EMISSION CALCULATIONS

BURNING 100-PERCENT RESIDUE

1. Particulate
   Allowable and maximum emissions = 443.5 x 10^6 Btu/hr x 0.2 lb particulate/10^6 Btu = 88.7 lb/hr

   Potential (uncontrolled) emissions: assume same as bagasse in AP-42 on a "dry" basis. Factor is 16 lb/ton bagasse on a wet basis.

   Convert to dry basis: 16 lbs/ton wet bagasse x 1 ton wet/0.45 ton dry = 35.6 lb/ton dry x 49,834 lb/hr residue (dry) ÷ 2,000 = 887.0 lb/hr.

2. Sulfur Dioxide (based on scrubber removal of 40%)
   Maximum emissions = 49,834 lb/hr residue (dry) x 0.004 x 2 x 0.6 = 239.2 lb/hr

   Potential (uncontrolled) emissions = 239.2 lb/hr ÷ 0.6 = 398.7 lb/hr

3. Nitrogen Oxides
   Maximum and Potential (uncontrolled) emissions: assume same factor as bagasse. Factor 1.2 lb/ton bagasse on a wet basis.
   Convert to dry basis: 1.2 lb/ton wet bagasse x 1 ton wet/0.45 ton dry = 2.67 lb/ton x 49,834 lb/hr residue (dry) ÷ 2,000 = 66.5 lb/hr

4. Other Pollutants
   Emissions data or factors not known to exist for other pollutants

BURNING FUEL OIL AT 250x10^6 Btu/hr

1. Particulate
   Allowable and maximum emissions = 250 x 10^6 Btu/hr x 0.1 lb particulate/10^6 Btu = 25.0 lb/hr

   Potential (uncontrolled) emissions: from AP-42 Table 1.3-1
   lb/10^3 gal = 10(S) + 3 = 10(1) + 3 = 13
   1,764 gal/hr x 13 lb/10^3 gal = 22.9 lb/hr

2. Sulfur Dioxide
   Maximum and Potential Emissions: from AP-42 Table 1.3-1
   lb/10^3 gal = 157 (S) = 157(1) = 157
   1,764 gal/hr x 157 lb/10^3 gal = 276.9 lb/hr

3. Nitrogen Oxides
   Maximum and Potential Emissions: from AP-42 Table 1.3-1
   60 lb/10^3 gal x 1,764 gal/hr = 105.8 lb/hr

4. Hydrocarbons
   Maximum and potential (uncontrolled) emissions: from AP-42, Table 1.3-1
   1 lb/10^3 gal x 1,764 gal/hr = 1.8 lb/hr

5. Carbon Monoxide
   Maximum and potential (uncontrolled) emissions: from AP-42, Table 1.3-1
   5 lb/10^3 x 1,764 gal/hr = 8.8 lb/hr

BURNING 100-PERCENT BAGASSE

1. Particulate
   Allowable and maximum emissions = 504.0 x 10^6 Btu/hr x 0.2 lb particulate/10^6 Btu = 100.8 lb/hr

   Potential (uncontrolled) emissions: from AP-42, Table 1.8-1
   16 lb/ton bagasse (wet) x 63,000 lb/hr bagasse (dry) ÷ 0.45 ÷ 2,000 = 1,120 lb/hr

2. Sulfur Dioxide (based on scrubber removal of 40%)
   Maximum Emissions = 63,000 lb/hr bagasse (dry) x 0.001 x 2 x 0.6 = 75.6 lb/hr

   Potential (uncontrolled) emissions = 75.6 lb/hr ÷ 0.6 = 126.0 lb/hr

3. Nitrogen Oxides
   Maximum and potential (uncontrolled) emissions: from AP-42, Table 1.8-1
   1.2 lb/ton bagasse (wet) x 63,000 ÷ 0.45 lb/hr bagasse ÷ 2,000 = 84.0 lb/hr*

4. Other Pollutants
   Emissions data or factors not known to exist for other pollutants.

* This figure could be greatly overestimated since a recent EPA study reported NO_x levels of 0.002 lb/10^6 Btu, equivalent to 1.0 lb/hr for this boiler ("Emission Test Report, U.S. Sugar Company, Bryant, Florida," Monsanto Research Corp., May 1980).

MAXIMUM EMISSIONS CALCULATIONS

1. Particulate
   Maximum emissions occur when burning 100-percent bagasse since heat input is greatest = 100.8 lb/hr

2. Sulfur Dioxide
   Maximum emissions occur when burning oil up to 250 x 10^6 MM Btu/hr with remainder of steam capacity supplied by bagasse residue
   SO_2 due to oil = 276.9 lb/hr
   Steam due to oil = 250 x 10^6 MM Btu/hr ÷ 1,050 Btu/lb steam x 0.8 = 190,476 lb/steam/hr
   Steam due to residue = 264,000 - 190,476 = 73,524 lb/steam/hr
   Residue required = 73,524 x 1,050 ÷ 0.625 ÷ 8,900 = 13,879 lb/hr (dry)
   SO_2 due to residue = 13,879 x 0.004 x 2 x 0.6 = 66.6 lb/hr
   Total SO_2 = 276.9 + 66.6 = 343.5 lb/hr

3. Nitrogen Oxides

Fuel-oil burning produces maximum NO_x emissions, with bagasse next. Therefore, maximum NO_x occurs when burning maximum fuel with the rest of the steam supplied by bagasse.

NO_x due to oil = 105.8 lb/hr
Steam due to oil = 190,746 lb steam/hr (see SO_2 above)
Steam due to bagasse = 73,524 lb steam/hr
Bagasse required = 73,524 x 1,050 ÷ 0.55 ÷ 8,000
= 17,546 lb/hr (dry)
NO_x due to bagasse = 17,546 x 2.67 ÷ 2,000 = 23.4 lb/hr
Total NO_x = 105.8 + 23.4 = 129.2 lb/hr

4. Hydrocarbons

Maximum emissions when burning fuel oil = 1.8 lb/hr

5. Carbon Monoxide

Maximum emissions when burning fuel oil = 8.8 lb/hr

ACTUAL EMISSIONS CALCULATIONS

Annual emissions for proposed Boiler 8 based on fuel mix presented in Table A-3 of PSD report for 184 day/yr. For off-season operation (120 days/yr), bagasse is not available; therefore, emissions based upon average fuel oil consumption with remainder of steam produced from residue and assuming maximum steam production of 264,000 lb/hr. This figure is much higher than will actually occur on average during off season.

1. Particulate (based upon allowables)

Crop season:
18.3 ton/hr residue x 2,000 x 8,900 x 0.2 lb/MM Btu x 24 x 184
÷ 2,000 = 143.8 ton/yr
7.5 ton/hr bagasse x 2,000 x 8,000 x 0.2 lb/MM Btu x 24 x 184
÷ 2,000 = 53.0 ton/yr
64 gal/hr x 8.1 x 17,500 x 0.1 lb/MM Btu x 24 x 184 ÷ 2,000 =
2.0 ton/yr

Off season:
Average steam due to oil = 6,900 lb/hr
Average steam due to residue = 264,000 - 6,900 = 257,100 lb/hr
Residue required = 257,100 x 1,050 ÷ 0.625 ÷ 8,900 = 48,531 lb/hr
48,531 lb/hr residue x 8,900 x 0.2 lb/MM Btu x 24 x 120 ÷ 2,000
= 124.4 ton/yr
64 gal/hr x 8.1 x 17,500 x 0.1 lb/MM Btu x 24 x 120 ÷ 2,000
= 1.3 ton/yr

Total = 324.5 ton/yr

2. Sulfur Dioxide

Crop season:

18.3 ton/hr residue x 0.004 x 2 x 0.6 x 24 x 184 = 387.9 ton/yr
7.5 ton/hr bagasse x 0.001 x 2 x 0.6 x 24 x 184 = 39.7 ton/yr
64 gal/hr x 157 lb/10^3 gal x 24 x 184 ÷ 2,000 = 22.2 ton/yr

Off season:

64 gal/hr x 157 ÷ 1,000 x 24 x 120 ÷ 2,000 = 14.5 ton/yr
48,531 lb/hr residue x 0.004 x 2 x 0.6 x 24 x 120 ÷ 2,000 = 335.4 ton/yr

Total= 799.7 tons/yr

3. Nitrogen Oxides

Crop season:

18.3 ton/hr residue x 2.67 lb/ton x 24 x 184 ÷ 2,000 = 107.9 ton/yr
7.5 ton/hr bagasse x 2.67 lb/ton x 24 x 184 ÷ 2,000 = 44.2 ton/yr
64 gal/hr x 60 lb/10^3 gal x 24 x 184 ÷ 2,000 = 8.5 ton/yr

Off season:

64 gal/hr x 60 ÷ 1,000 x 24 x 120 ÷ 2,000 = 5.5 tons/yr
48,531 lb/hr residue ÷ 2,000 x 2.67 x 24 x 120 ÷ 2,000 = 93.3 tons/yr

Total = 259.4 tons/yr

4. Hydrocarbons

Emissions are due to oil burning only.
64 gal/hr x 1 lb/10^3 gal x 24 x (184 + 120) ÷ 2,000 = 0.2 ton/yr

5. Carbon Monoxide

Emissions are due to oil burning only.
64 gal/hr x 5 lb/10^3 gal x 24 x (184 + 120) ÷ 2,000 = 1.2 ton/yr

POTENTIAL EMISSIONS CALCULATIONS

Potential emissions based upon burning worst-case emitting fuel all the time and 304-day operation per year. No controls considered.

1. Particulate

Worst-case fuel is bagasse at maximum steam production.

63,000 lb/hr bagasse (dry) ÷ 2,000 x 35.6 lb/ton = 1,121.4 lb/hr
1,121.4 lb/hr x 24 x 304 ÷ 2,000 = 4,091 ton/hr

2. Sulfur Dioxide

Worst-case fuel is oil, burning up to 250 MM Btu/hr.
Remainder of steam produced from residue.

Oil: 1,764 gal/hr x 157 lb/10^3 gal = 276.9 lb/hr = 1,010.3 ton/yr
Residue: 13,879 lb/hr x 0.004 x 2 = 111.0 lb/hr = 405.0 ton/yr

Totals = 387.9 lb/hr = 1,415.3 ton/yr

3. Nitrogen Oxides
   Worst-case fuel is oil, with bagasse next.
   Oil = 105.8 lb/hr (see Maximum Emissions Calculations)
   = 386.0 ton/yr
   Bagasse = 23.4 lb/hr = 85.4 ton/yr

   Totals = 129.2 lb/hr = 471.4 ton/yr

4. Hydrocarbons
   Emissions are due to oil burning.
   1.8 lb/hr x 24 x 304 ÷ 2,000 = 6.6 ton/yr

5. Carbon Monoxide
   Emissions are due to oil burning.
   8.8 lb/hr x 24 x 304 ÷ 2,000 = 32.1 ton/yr

ATTACHMENT B

INSTALLATION, OPERATING, AND MAINTENANCE INSTRUCTIONS

FOR

TURBULAIRE® SCRUBBER

TYPE D

JOY MANUFACTURING COMPANY
Western Precipitation Division
1000 W. Ninth St.
Los Angeles, California 90015

CONTENTS

FIGURES

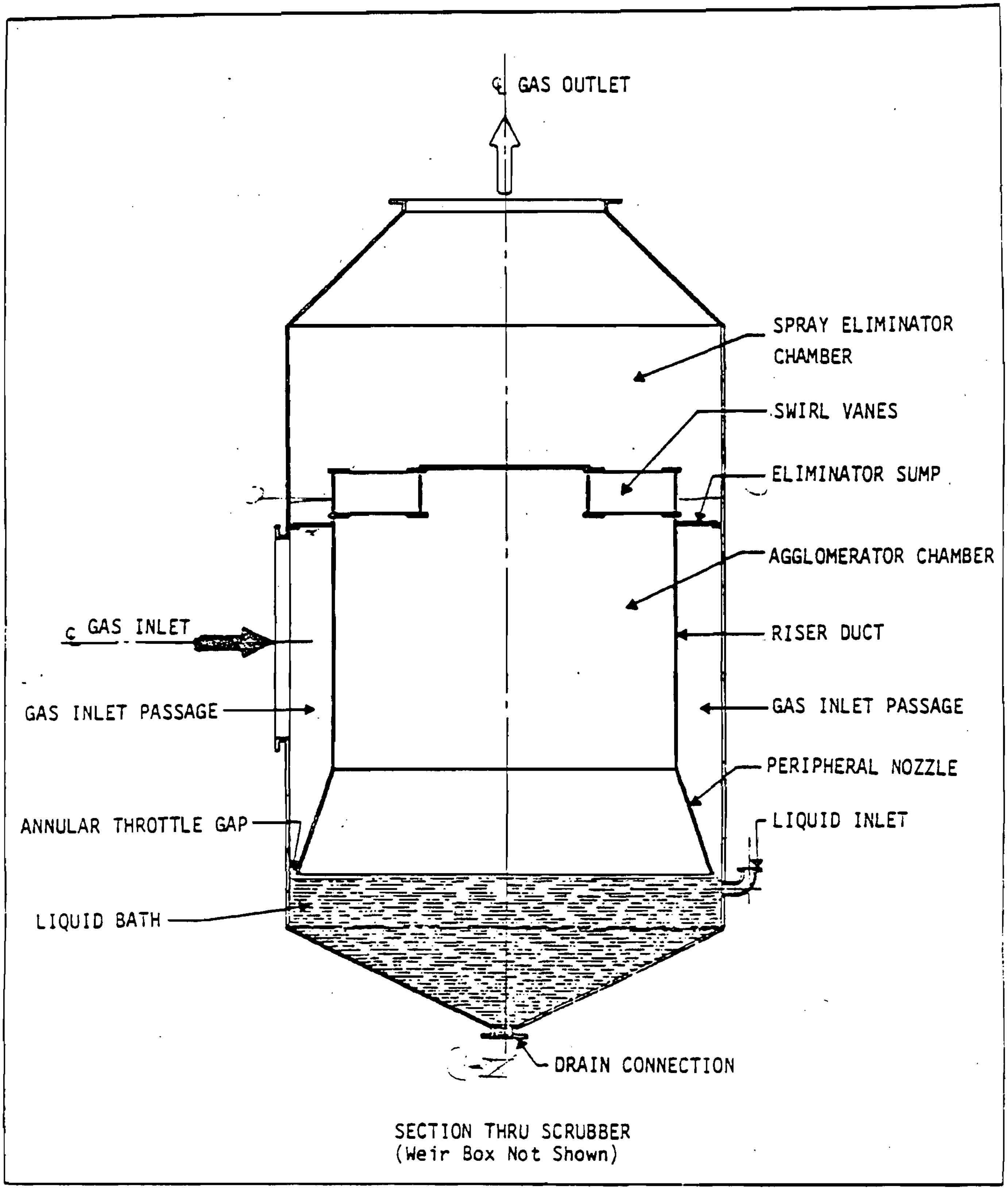


Figure 1. Turbulaire® Scrubber, Type D-B, Sizes 20 thru 64

DESCRIPTION

The Type D Turbulaire® Scrubber (Figure 1) consists of a vertical cylindrical shell with conical top and conical hopper on the lower end. The scrubber is divided into two chambers; the agglomerator chamber and the eliminator chamber.

The agglomerator chamber is in the lower portion of the scrubber and consists of the hopper with liquid bath, the gas inlet passage with conical throttle and the liquid level regulating assembly.

The eliminator chamber is above the agglomerator chamber and consists of a set of swirl vanes and a sump preceding the gas outlet.

TYPE & SIZE DESIGNATION

1 D B MS R 32

- 32 — Size
- R — Shell Lining if specified
- MS — Shell Material
- B — Hopper Type
- D — Design Type
- 1 — Number of Units

The scrubber has the gas inlet located radially on the side of the shell and the gas outlet at the top center. The agglomerator cylinder is surrounded by the gas inlet passage. The shell and the peripheral nozzle of the agglomerator chamber form an annular throttling gap at the bottom of the gas inlet passage. The normal operating level of the scrubbing liquid bath is just below the throttling gap.

Swirl vanes are mounted in the top of the agglomerator cylinder. A horizontal plate joining the agglomerator with the shell forms the eliminator sump. Weep holes drain the liquid from the eliminator sump into the scrubbing liquid bath in the hopper.

A liquid level regulating assembly is mounted on the lower exterior region of the shell. This assembly consists of a gas lock release pipe, weir box with liquid level control, and a seal pipe with overflow. The liquid inlet is located just above the hopper. Access doors are provided in the hopper and in the upper region of the shell.

Construction material for the standard scrubber is mild steel. Optional materials of construction may be: mild steel lined with rubber, lead or coated with epoxy resin; 304 or 306 stainless steel; and fiber reinforced polyester.

FIELD INSTALLATION

Field installation of the scrubber is as follows:

1. Set the unit on the foundation and attach the anchor bolts. Level unit by shimming between unit and foundation.

NOTE: Vertical and horizontal alignment of the scrubber is important to ensure an even circumferential dimension between the peripheral nozzle and quiescent liquid level.

2. Connect the inlet and outlet flues to the unit. It is recommended that inspection doors, adjacent to the scrubber, be included in the customer's flues.

NOTE: Dynamic and dead load forces from customer's fan, equipment and flues must not be transmitted to the scrubber equipment.

3. Attach the sight glass and weir box to the scrubber, then connect the seal pipe overflow to a drain line.

4. Connect the hopper outlet to a drain line. The drain line should contain a valve for flow balancing purposes.

PREPARATION OF THE SCRUBBER FOR OPERATION

The scrubber is designed to operate under the conditions in the operating data sheet in the front of the manual.

Prior to turning on the flue gas, liquid flow and liquid level should be established as follows:

1. Remove the weir box cover.

2. Turn on the liquid supply. By means of a flow meter or other measuring device, adjust the flow of the inlet liquid until the rate prescribed on the data sheet is attained.

3. Open the valve at the hopper outlet and establish a flow of liquid adequate to remove the slurry from the hopper.

4. Raise or lower the liquid level control as required until the liquid in the scrubber reaches and maintains a steady level, approximately 1/2-inch below the peripheral nozzle. This level is indicated by a red line painted on the weir box. Tighten the clamp which secures the level control in place.

NOTE: The liquid level control and liquid inlet rate may require adjustment to comply with rated pressure drop and outlet gas conditions.

5. Replace the weir box cover. The scrubber is now ready to receive flue gas.

If the tank is lined with lead, rubber, epoxy resins or other material which may deteriorate at high temperatures, the temperature of the inlet gas must be adjusted within limits compatible with these materials as noted after operating instruction.

NOTE: Unless otherwise recommended, 95% to 99% of the slurry should be removed through the valve at the hopper outlet. Only 1% to 5% should be removed through the weir box overflow pipe.

OPERATION

Operation of the scrubber requires only that the fan be turned on to move flue gas through the scrubber.

As flue gas enters the scrubber through the inlet, its speed is increased to the desired operating velocity as it passes through the throttling gap. The dust-laden gas is then discharged at high velocity and penetrates deeply into the liquid bath wherein the dust combines with the liquid to form a slurry which is discharged through the hopper outlet valve. The turbulence resulting from the entrance of the high velocity gas into the scrubbing bath is sufficient to produce a dense spray. This spray is removed from the gas by the swirl vanes.

The scrubber should continue to operate at constant efficiency if the gas volume, temperature and dust load do not change. If there is an increase in the dust load, it may be necessary to increase the flow rate of the scrubbing liquid, in which case, the hopper outlet valve must be adjusted to maintain the operating liquid level. A decrease in the dust load will permit decreasing the scrubbing liquid flow rate.

The efficiency of the unit may be increased by: increasing pressure drop through unit, cooling inlet gases if necessary, and increasing the inlet liquid rate, described as follows:

1. Increase pressure drop through the unit by restricting the nozzle opening or by increasing the gas flow through the unit.

The nozzle opening can be restricted by adding material to the nozzle opening and thus cut down the size of the opening. The opening is designed so that at the gas density and volume specified, the required pressure drop should be obtained. Sometimes the gas density or the volume are not that which is calculated and, if the pressure drop is low, it is necessary to close down on the opening. This is fairly easily accomplished and, by doing this, the velocity of the jet is increased into the liquid pool and, therefore, increases the efficiency of the unit.

The volume of air should never exceed the maximum allowable outlet gas volume as specified on the data sheet. This maximum volume cannot be exceeded without entraining some of the scrubbing liquid, and carrying it into the outlet flue.

Gas flow through the unit can be increased by opening the fan dampers or by introducing infiltration air into the flue through a damper.

If the scrubber is operating well below the maximum outlet gas volume, the simplest way to increase the pressure drop through the unit is to increase the fan delivery until the design pressure drop is reached.

2. <u>Introduce liquid sprays ahead of the scrubber inlet to humidify the gases entering the scrubber</u>. This system is employed whenever inlet gas temperatures are high enough to damage the lining of the shell. Changing the specified water flow to the spray nozzles is not recommended since this will change inlet gas density beyond scrubber design limits.

3. <u>Increase the inlet liquid rate</u>. This will also bring the temperatures of the gas down to saturation quickly. However, as the liquid rate is increased, the liquid level control will have to be reset until equilibrium conditions are maintained without gas passing through the unit. Increase of the liquid rate will give lower outlet gas temperatures and also lower outlet liquid temperatures.

MAINTENANCE

Although the scrubber should operate continuously with minimum maintenance some may be required. This includes: removing any build-up of dust on the peripheral nozzle which would impair operation, and periodically cleaning out the scrubber and liquid seal pipe to prevent clogging of the outlet.

In addition, situations may be encountered which may impair the operation of the scrubber:

1. Plugging of the Overflow Pipe
   Occasionally on some dusts (generally those associated with fluorides), there may be some plugging of the overflow pipe which leads from the scrubber to the weir box. This plugging is due to settling out or deposition of particles in the pipe and can generally be relieved by one or two methods.

   One method is to periodically clean out the pipe with a reamer or a scraper of some sort. For those scrubbers with rubber, lead, or plastic lining, care should be taken that the lining is not pierced.

   Another method is to increase the velocity of liquid through the pipe by closing down on the cross sectional area. This is accomplished by laying pieces of tubing in the overflow pipe and building up enough tubing so that the cross sectional area of the pipe is gradually reduced. The velocity of liquid for materials which tend to settle out should be a minimum of 2 to 3 fps or higher.

2. Cold Weather Operation
   During periods of cold weather, care must be taken to prevent freezing of the liquid in the scrubber and in the supply lines. It may be necessary to insulate one or both. During periods of shutdown, the scrubber and liquid lines should be drained unless some method is employed to keep temperatures above the freezing point.

AUTOMATIC CONTROL RECOMMENDATION

An automatic liquid level control system is available as an optional extra from Western Precipitation Division.

The system consists of the following components:

a. Displacer type level control unit (Magnetrol)

b. Solenoid valve

c. Strainer

d. Piping and pipe fittings as required for field assembly.

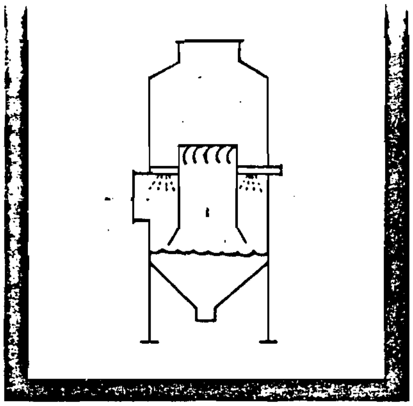
The system is normally shipped loose for field assembly by the customer. Hook-up connections are provided on the hopper and the scrubber body.

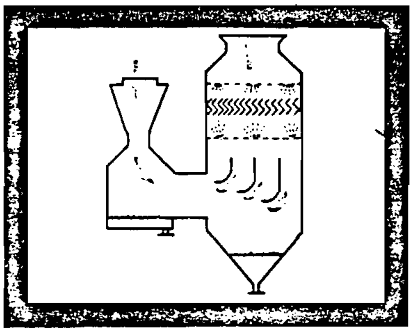
OPERATION

The liquid level control unit uses a solid block displacer - heavier than the liquid - which is suspended from a helical spring. A rising liquid level imparts buoyancy to the displacer, lessening the load on the spring, thus, the displacer moves upward. A magnetic sleeve connected to the displacer also moves upward inside a non-magnetic enclosing tube, attracting a permanent magnet attached to a mercury switch (or pneumatic pilot valve). This actuates and closes the solenoid valve, and make-up water to the scrubber is shut-down. As the liquid level recedes, the magnetic sleeve and displacer drops allowing the magnet and switch element to return to the normal operating level. This actuates and opens the solenoid valve allowing flow of makeup water to the scrubber.

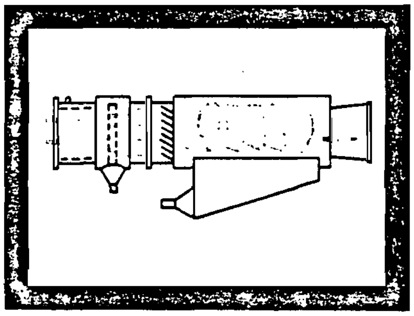
Thus, there is no possibility of excessive high or low liquid levels in the scrubber.

A cross is provided in the line to allow periodic flushing and cleanout of the system.





Western Precipitation™ Gas Scrubbers

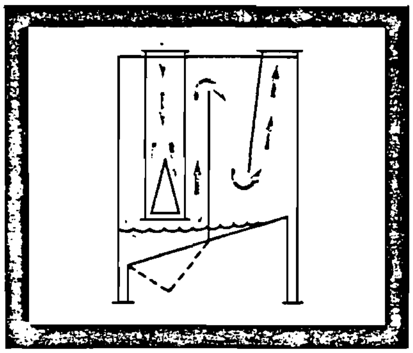


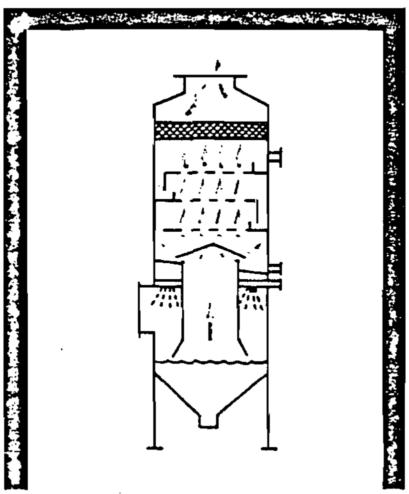
World-Wide Response/Ability

WESTERN PRECIPITATION DIVISION

JOY™

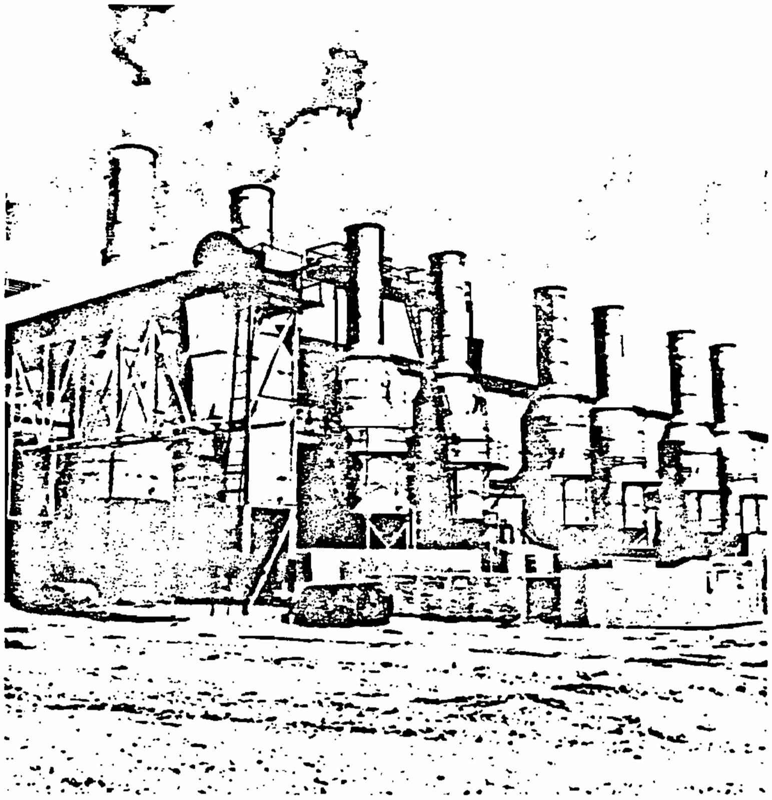
Joy Industrial Equipment Company
P.O. Box 2744, Terminal Annex
Los Angeles, California 90051
(213) 240-2300

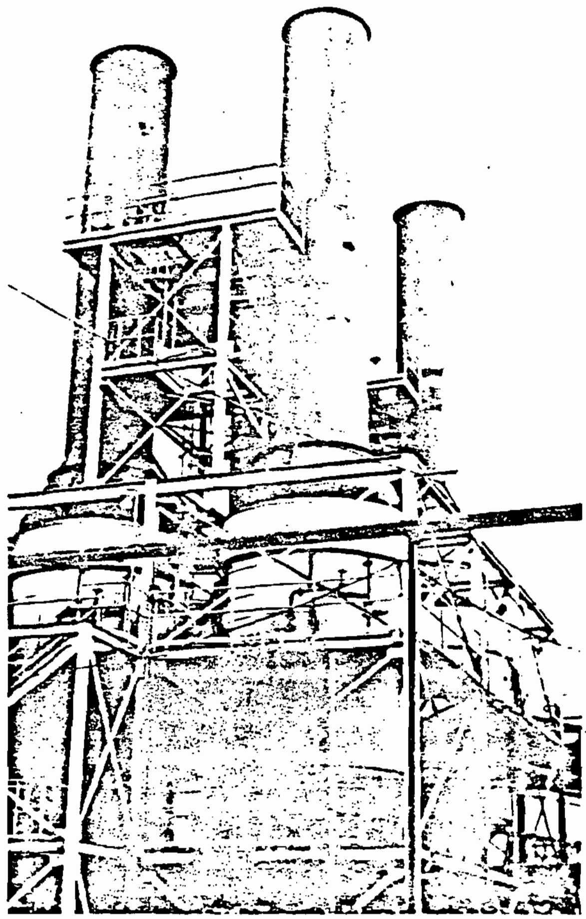




Type "D" Turbulaire® Scrubber

High efficiency / low energy / non-plugging / for large volumes.





Type "D" Turbulaire® Scrubbers are used where dust particle sizing and process conditions require low energy inputs (Scrubber pressure drops less than 14 inches of water). These energy requirements are below the range in which the collecting mechanisms of conventional venturi scrubbers begin to take full effect. Hence, our Type "D" units often match the performance of venturi scrubbers while saving 20 to 50 percent in operating horsepower.

The Type "D" model has a vertical flow design which requires a minimum of floor space. The cylindrical configuration improves rigidity with light gage "unitized" construction.

How It works

A patented peripheral gas nozzle (U.S. patent 3726513) combines a low energy venturi effect with collection by impingement on the liquid bath. This combination provides optimum energy utilization at low pressure drop.

In order to accommodate changes in process conditions or more stringent emission codes, the unit is designed to allow for variations in pressure drop by means of a simple internal adjustment of the peripheral gas nozzle.

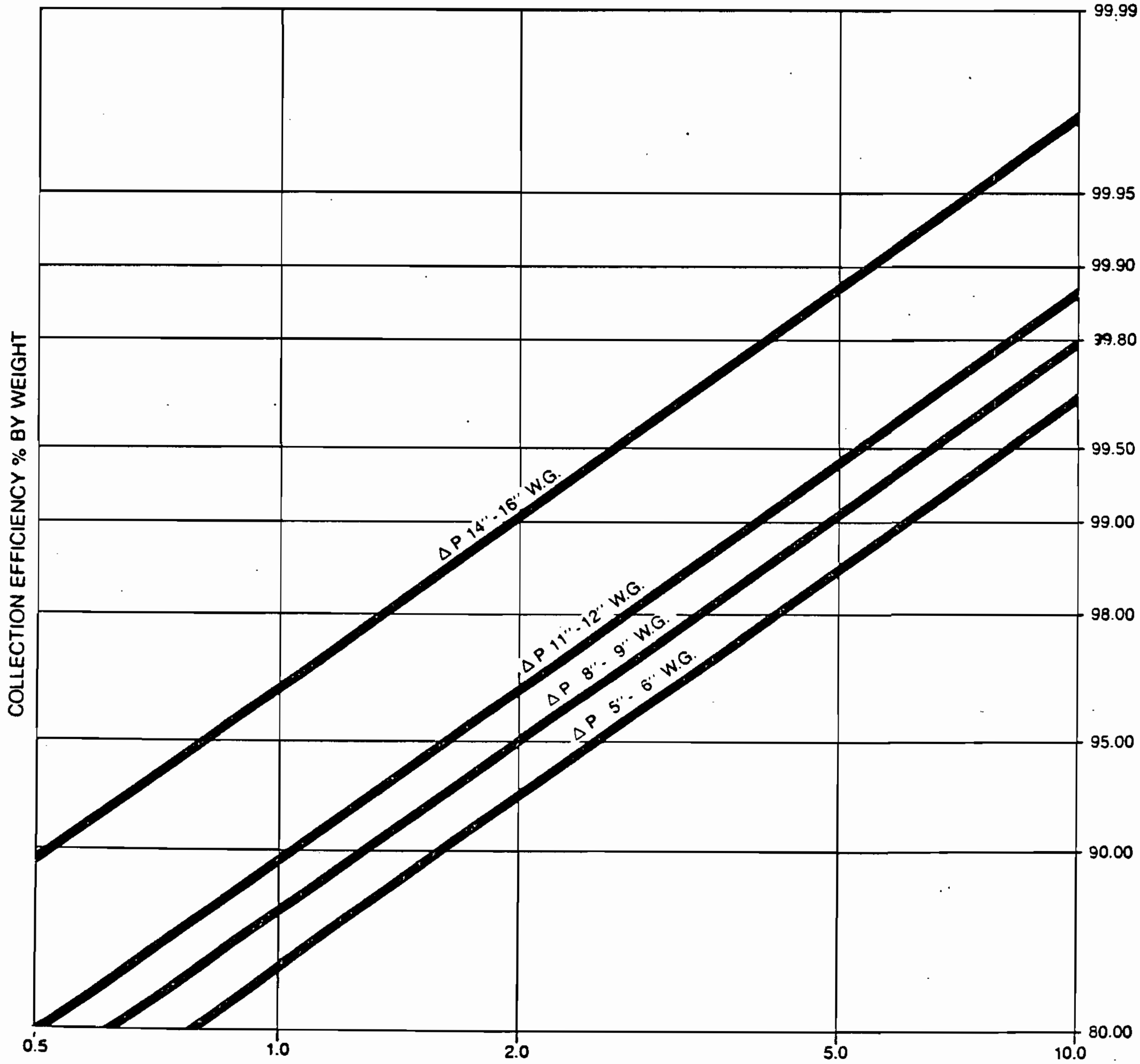
Slurries are kept in suspension in the sump by the action of the gases being scrubbed. Mist elimination is accomplished with the centrifugal action of a set of swirl vanes, and the droplets once separated from the gas stream are returned by gravity into the sump.

Water needs are kept to a minimum by the unit's ability to recirculate the heavily concentrated slurries often containing as much as 5.0% solids by weight. The top gas outlet configuration makes stack connection simple; the flanged slurry drain can be connected to settling tanks or piped for disposal with ease.

The Type "D" is simple, rugged, with no moving parts and excellent non-plugging characteristics, and it can be made of a variety of corrosion-resistant metals as well as lightweight, low cost fiberglass reinforced polyester (FRP).

Turbulaire* Scrubbers Comparative Fractional Efficiency Curves*

COLLECTION EFFICIENCY VS PARTICLE SIZE



PARTICLE DIAMETER IN MICRONS

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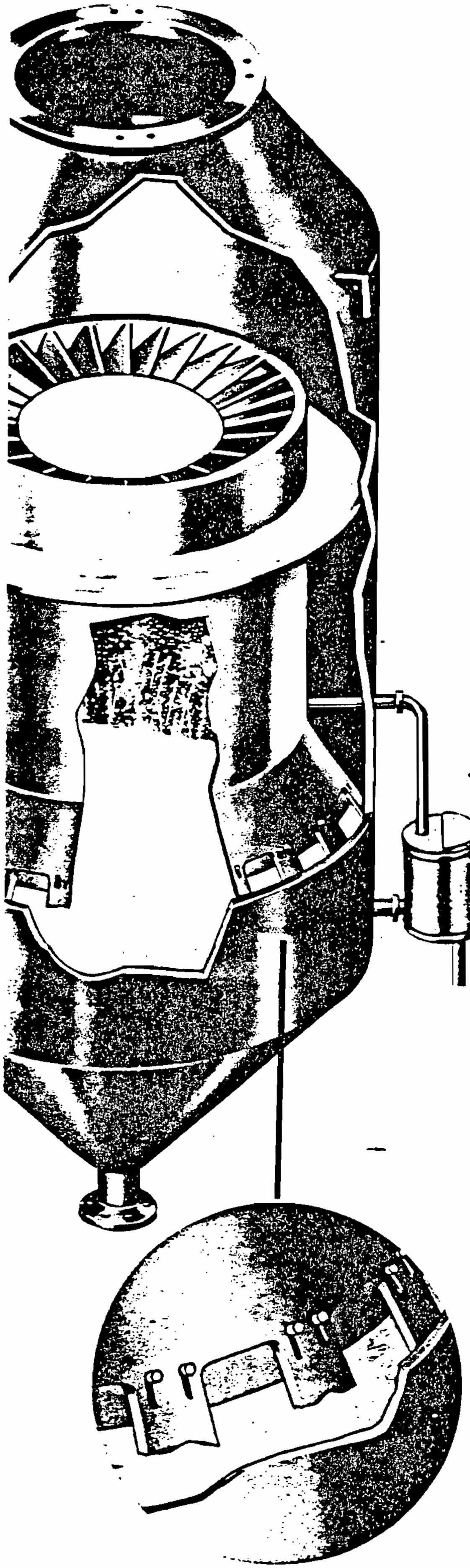
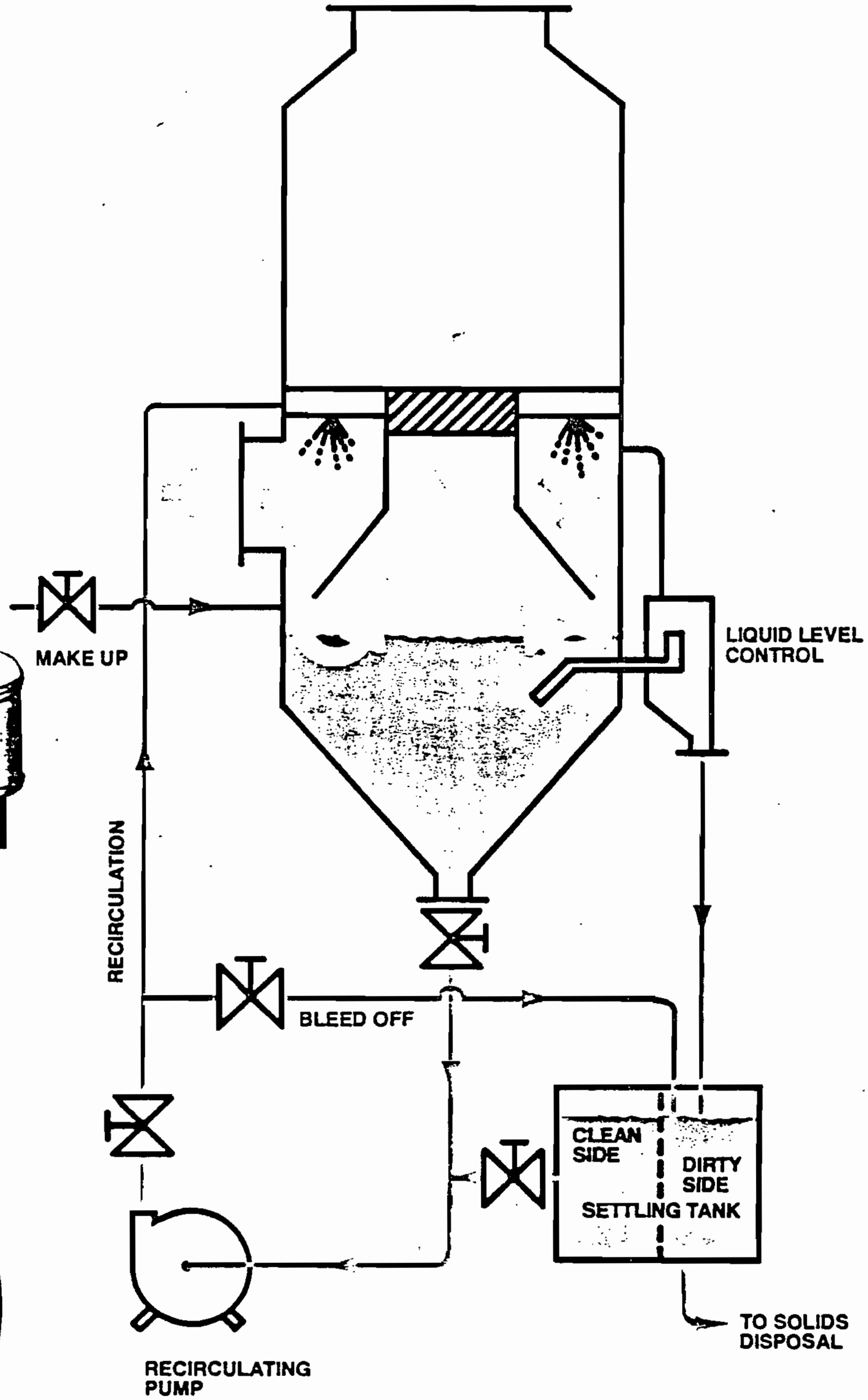
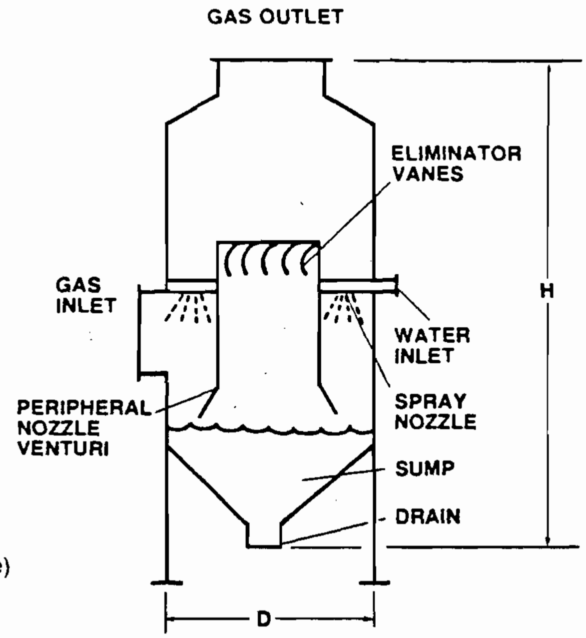
Western Precipitation™ Gas Scrubbers **Type "D"**



Type "D" Process Flow Diagram





AVAILABLE OPTIONS

Support Assembly (Drain flange 2'-6" to grade)
Discharge valve, Cast iron or Rubber lined
Automatic water supply control
Manometer and Fittings
Pump and Motor
Fan and Motor

EQUIPMENT SIZING

SCRUBBER SIZE	DESIGN ACFM OUTLET	DRAIN SIZE (IN)	SUMP CAPACITY (GAL)	DIAMETER D	HEIGHT H	INLET DIAMETER	OUTLET DIAMETER
4	6,900	3	157	4'-0"	10'-3"	1'-7"	2'-9"
4.5	8,700	3	208	4'-6"	11'-1"	1'-9"	3'-1"
5	10,700	3	269	5'-0"	12'-1"	2'-0"	3'-5"
5.5	13,000	3	340	5'-6"	13'-0"	2'-2'	3'-9"
6	15,500	3	423	6'-0"	13'-11"	2'-4"	4'-1"
6.5	18,200	3	517	6'-6"	14'-11"	2'-7"	4'-5"
7	21,100	3	624	7'-0"	15'-10"	2'-9"	4'-9"
7.5	24,300	4	744	7'-6"	16'-8"	2'-11"	5'-1"
8	27,600	4	877	8'-0"	17'-8"	3'-2"	5'-5"
8.5	31,100	4	1,026	8'-6"	18'-8"	3'-4"	5'-9"
9	34,900	4	1,189	9'-0"	19'-7"	3'-6"	6'-1"
9.5	38,900	4	1,370	9'-6"	20'-5"	3'-9"	6'-5"
10	43,100	4	1,566	10'-0"	21'-4"	3'-11"	6'-9"
10.5	47,600	4	1,781	10'-6"	22'-4"	4'-1"	7'-1"
11	52,200	6	2,014	11'-0"	23'-2"	4'-4"	7'-6"
11.5	57,100	6	2,266	11'-6"	24'-1"	4'-6"	7'-10"
12	62,200	6	2,537	12'-0"	25'-0"	4'-8"	8'-2"
12.5	67,400	6	2,830	12'-6"	26'-0"	4'-11"	8'-6"
13	72,900	6	3,144	13'-0"	26'-10"	5'-1"	8'-10"

EQUIPMENT SPECIFICATIONS

Scrubber of cylindrical shape shall be of the high efficiency inertial-orifice type with radial inlet. The gas to be cleaned passes through a peripheral nozzle and is jetted in a near vertical direction and at high velocity into a static liquid bath, the level of which is maintained slightly below the bottom of the gas nozzle by means of an adjustable weir. Weir box shall be equipped with a gas-lock release mechanism. After leaving liquid bath, gases shall pass through a centrifugal type spray eliminator and exit the scrubber through the top vertical discharge.

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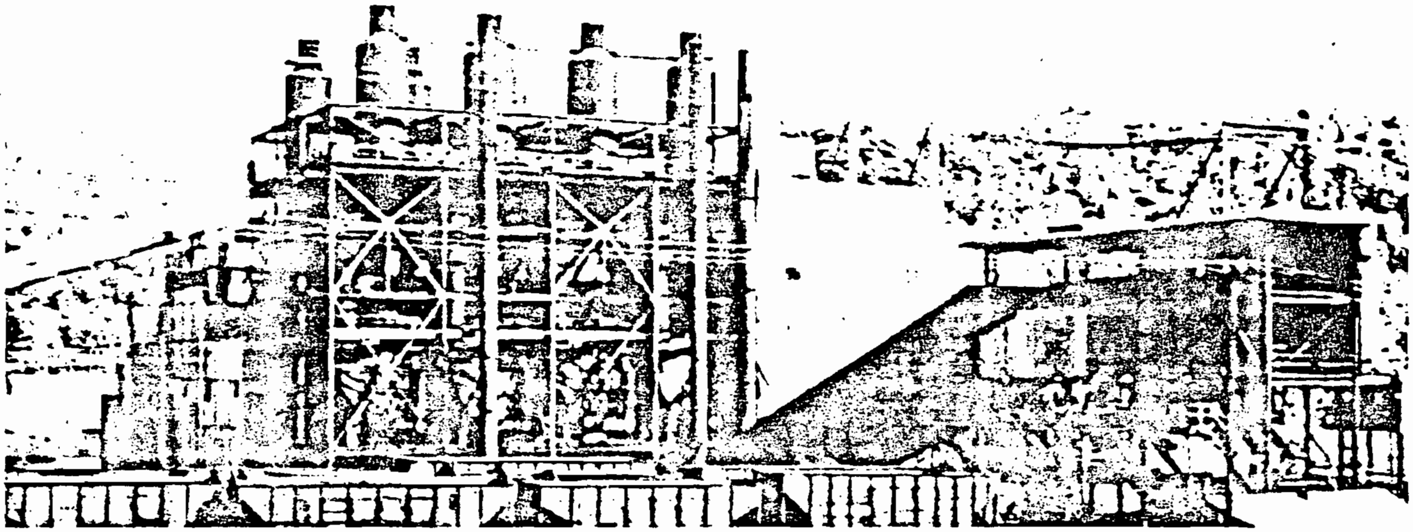
"Turbulaire" scrubbers have been used successfully to control emissions from many industrial process operations, including combustion, chemical, mining, metallurgical, etc.



Some "Turbulaire®" features

Scrubbing slurry processing expenses (clarifiers, pumps, etc.) are kept down by making every drop count. Special sump designs maintain high turbulence within the scrubbing liquid. The high turbulence permits higher slurry concentrations reducing the possibilities of solid build-up or system stoppage. (Most of our units operate at liquid to gas ratios of less than 3GPM/1,000 ACFM.) Therefore less processing equipment is required.

Simple, compact designs save valuable in-plant space and make minimum operating and maintenance demands.

"Turbulaire" scrubbers are often used in conjunction with other collection equipment. Flexibility in space needs and efficiency make "Turbulaire" scrubbers excellent add-on units, especially for already tight plant layouts.

Each "Turbulaire" scrubber model can be adapted to meet virtually any corrosion problem. For example, units can be made of mild or stainless steel, FRP, or with corrosion resistant plastics, rubber, lead or acid brick liners.

ATTACHMENT C

BASIS FOR SO_2 REMOVAL EFFICIENCY

Measurement of SO_2 emissions from bagasse-burning boilers was conducted by EPA at the U.S. Sugar Mill in Clewiston during the 1978 to 1979 crop season. SO_2 emissions from residue-burning boilers at SCGC in Belle Glade were measured by ESE during the 1979 to 1980 crop season, and again during April 1981. The results of those tests are shown in Table C-1.

Table C-2 compares actual emissions with those predicted by material balance. During the most recent test, samples of residue as burned were analyzed for sulfur content. A copy of the stack test report is included with this submittal as Attachment F. For the earlier tests, the sulfur content of bagasse as published in AP-42 was assumed; for residue, an average value based on previous ultimate fuel analyses conducted by SCGC was assumed.

Tests performed for EPA at U.S. Sugar, Bryant in December 1979 failed to measure SO_2 in scrubbed gases above the detection limit of 3.4 mg/m^3, corresponding to emissions less than 1 lb/hr from a boiler producing 146,000 lb/hr steam (Peters, 1980). Results of the more recent tests summarized here indicate that from 39 to 82 percent of the theoretical sulfur from residue and about 83 percent from bagasse are eliminated from the gas stream. It is not known what proportion of this removal occurs in the scrubber itself, and what part of the sulfur remains in the bottom ash, or is absorbed by the fly ash.

ATTACHMENT C

BASIS FOR SO_2 REMOVAL EFFICIENCY
(Continued, Page 2 of 2)

Table C-1 contains the results of a test conducted simultaneously at the inlet and outlet of the scrubbers servicing SCGC Boiler 2. The scrubber itself is seen to remove 27 percent of its inlet SO_2, which accounts for 11 percent out of the total 70-percent theoretical loss. This shows that the scrubber itself is not responsible for the total SO_2 loss through the system. These figures are the result of only one inlet/outlet test and should not be considered representative of average system behavior.

Regardless of the actual mechanism of removal, these tests demonstrate that only a fraction of the sulfur contained in bagasse and residue is emitted as gas from the scrubbers. An estimate of actual emissions while burning these fuels is necessary to determine air quality impacts. A worst-case emissions estimate was made by assuming a sulfur content of 0.4 percent in residue and 0.1 percent in bagasse on a dry basis, and an overall sulfur loss of 40 percent of the theoretical maximum.

Table C-1. Summary of SO_2 Emissions Tests

Boiler	Test Location	Test Date	Measured SO_2 Emissions (lb/hr) North Stack	South Stack	Center Stack	Average	Steam Rate (lb/hr)
The following tests were conducted at SCGC while burning 100-percent bagasse residue.							
1	Outlet	4/2/81	14	20	--	34	120,000
2	Outlet	4/3/81	36	24	--	60	125,000
2	Inlet	4/3/81	--	--	--	82	125,000
4	Outlet	4/3 to 4/4/81	49	37	59	145	240,000
1	Outlet	3/20/80	--	--	--	75	81,200
2	Outlet	3/20/80	--	--	--	76	94,500
The following tests were conducted at U.S. Sugar, Clewiston while burning 100-percent bagasse. Values are averages of three tests.							
1	Outlet	12/3 to 12/4/79	--	--	--	22	212,000
2	Outlet	12/4 to 12/5/79	--	--	--	17	196,100
5	Outlet	12/5 to 12/6/79	--	--	--	1.2	62,400

Source: ESE, 1981.

Table C-2. Combined Boiler/Scrubber SO_2 Removal Efficiency

Boilers	Steam Load (lb/hr)	Heat Input* (10^6 Btu)	Estimated* Fuel Rate (dry lb/hr)	Sulfur Content (%) dry basis	Potential SO_2 Emissions (lb/hr)	Actual SO_2 After Scrubbers (lb/hr)	SO_2 Loss (%)
Residue Tests							
1 SCGC	120,000	201.6	22,652	0.414†	188	34	82
2 SCGC	125,000	210.0	23,596	0.426†	201	60	70
4 SCGC	240,000	403.2	45,304	0.435†	394	145	63
						Average =	72
1 SCGC	81,200	136	15,280	0.4**	122	75	39
2 SCGC	94,500	159	17,865	0.4**	143	76	47
						Average =	43
Bagasse Tests							
1 USSC	212,800	406	50,750	0.1**	102	22	70
2 USSC	196,100	374	46,750	0.1**	94	17	82
5 USSC	62,400	119	14,675	0.1**	30	1.2	96
						Average =	83

* Basis: 1,050 Btu/lb steam.
62.5-percent efficiency in burning residue, 55-percent efficiency for burning bagasse (8,900 Btu/lb dry residue, 8,000 Btu/lb dry bagasse).
† Measured.
**Assumption based on past fuel analyses.

Note: SCGC--Sugar Cane Growers Cooperative residue burning.
USSC--U.S. Sugar, Clewiston bagasse burning.

Source: ESE, 1981.

ATTACHMENT D
BACT JUSTIFICATION

Reference Section IV F.10--Reasons for Selection and Discussion of Control Systems

SUMMARY

A Joy Turbulaire Type D Impingement scrubber is selected for Sugar Cane Growers Cooperative (SCGC) as BACT for the proposed boiler on the basis of environmental, energy, and economic impacts; proven industry control techniques and systems; and operating experience. A BACT emission limit of 0.2-lb particulate/MM Btu heat input when burning carbonaceous fuel is selected based upon source-specific operating data and experience. A BACT limit of 0.15 lb SO_2/MM Btu (bagasse), 0.54 lb SO_2/MM Btu (bagasse residue), and 2.10 lb SO_2/MM Btu (fuel oil) is selected for the proposed boiler based upon maximum anticipated fuel sulfur content and SO_2 loss of 40 percent of theoretical when burning bagasse or bagasse residue. This SO_2 loss is based upon source test data obtained from existing boilers at SCGC's mill, which demonstrates 40-percent removal can be reasonably met. A discussion of the control systems considered and the justification for BACT selection follows.

AVAILABLE PARTICULATE CONTROL TECHNOLOGY

WET SCRUBBER

Scrubbers are the only control devices currently in operation on bagasse/oil-fired steam boilers in the Florida sugar industry. These scrubbers, mainly of the impingement type, are also utilized on bagasse residue-fired boilers, which in Florida are only in operation at the SCGC mill. The most important design parameters for scrubbers are the liquid-to-gas ratio (amount of water used per unit volume of gas treated) and the intimacy of contact between the liquid and gas phases.

The venturi and spray impingement scrubbers were the wet scrubber designs considered for SCGC. The required particulate emission rate (0.2-lb/MM Btu heat input due to carbonaceous fuel) can be achieved by either system and has been guaranteed by the manufacturer.

In an impingement scrubber, the gas to be cleaned passes through a peripheral nozzle and is guided downward at high velocity into a liquid bath. The level of the liquid bath is maintained slightly below the nozzle by means of an adjustable weir. Collection of flue gas particles is by both direct impaction with the liquid bath and by collision with droplets atomized by the action of the gas stream upon the liquid bath. Mist elimination, achieved by centrifugal action and swirl vanes, precedes gas discharge. The wastewater stream is discharged through a slurry drain (see Attachment B).

In the venturi scrubber, the gases are passed through a venturi tube in which low-pressure water is added at the throat. In spite of a relatively short contact time, extreme turbulence in the venturi promotes intimate contact. The wetted particles and droplets are collected in a mist elimination device. For a given collection efficiency, these devices normally require a greater pressure drop than the impingement scrubber. In addition, pretreatment mechanical collectors are normally necessary to remove the larger abrasive particles and decrease wear on the venturi surfaces.

FABRIC FILTER

Particulate emission controls via fabric filtration techniques (baghouse) have not been installed on any bagasse or residue-fired boiler. The principal drawback foreseen by potential users is a fire danger resulting from collection of combustible carbonaceous fly ash. Fires have occurred with both wood- and municipal solid-waste-fired boilers fitted with baghouses. The fire potential could possibly be reduced by extensive modifications and precautions, but most such measures have not been demonstrated in actual application.

Additional problems with baghouses are plugging, solid waste disposal of a dry product, and potential high maintenance costs for filter replacement. A disadvantage to fabric filtration is its inability to remove other primary gaseous pollutants from the gas stream. Another control device would be required to remove soluble pollutants such as SO_2. This incapability is significant when such inherent removal is proposed as Best Applicable Control Technology (BACT).

ELECTROSTATIC PRECIPITATORS

Electrostatic precipitators (ESP) are in operation on wood- and solid waste-fired boilers. However, they have not been applied to bagasse- or residue-fired boilers. Precipitator vendors contacted recently and a study conducted several years ago indicate that electrostatic precipitation of bagasse and residue ash would probably not be feasible. The vendors also caution against possible fire hazard and explosion potential.

Particulate collection in an ESP is accomplished by first imparting an electrical charge to the particles, allowing the charged particles to migrate to a collecting electrode, and dislodging the collected particles from the collecting electrodes. Particle charging is normally accomplished with a high-voltage DC corona. Particle removal is performed by rapping or vibrating the collecting electrodes.

ESPs, which must be guarded against corrosion, have the inherent disadvantage of removing only particulate matter. Another control device would be needed to remove soluble pollutants such as SO_2. Disposal of a dry solid waste product would also be required.

AVAILABLE SULFUR DIOXIDE CONTROL TECHNOLOGY

SO_2 SPRAY-TYPE ABSORPTION TOWER

Gas absorption equipment is designed to provide thorough contact between the gas and liquid solvent in order to permit interphase diffusion of the dissolved materials. The rate of mass transfer (absorption) is largely dependent upon the water surface exposed by liquid dispersion. The liquid is introduced at the top of the tower through spray nozzles, while the gas is introduced at the bottom to pass upward through the liquid. This provides the highest possible efficiency because the solute concentrations in the gas stream decrease as the gas rises through the tower and, as a result, there is constantly a fresher solvent available for contact with the least concentrated gas phase. This gives maximum average driving force for the diffusion process throughout the entire column. The collection efficiency depends on the height of the tower and the liquid dispersion mechanism, which are directly related to the pressure drop and energy requirements.

In some systems the hot flue gases completely dry the absorbing solvent, allowing collection and disposal of the dry particulate. This would require an additional particulate removal device after the SO_2 scrubber. Spray drying is currently in the development/demonstration stage in the United States.

SO_2 SCRUBBING SLURRY

Addition of a sodium, alkali, limestone, or lime reagent to a scrubbing water stream significantly increases the absorption of SO_2. The slurry can be introduced to a single-stage scrubber in which both particulate and SO_2 removal is achieved. The cost of chemicals, all slurry handling mechanisms, slurry preparation, and additional power costs, would be added to the cost of a water-only scrubbing unit. A second method is to provide an add-on flue gas desulfurization (FGD) system after the particulate removal device. In this manner, particulate removal is achieved in the first stage with water only. This greatly decreases slurry requirements because particulate matter will no longer "foul" the absorption reagent, and the potential for recycle is improved. However, additional capital expenditure is necessary and an increased pressure drop results in increased operating costs.

FGD scrubbing systems currently in operation in the United States include lime/limestone scrubbing, sodium scrubbing (throwaway), and double alkali scrubbing. The Wellman-Lord process and spray-drying processes are in the development and/or demonstration stage.

AVAILABLE NITROGEN OXIDES CONTROL TECHNIQUES

Several techniques for controlling nitrogen oxide (NO_x) formation in boilers are currently available. These include:

1. Low excess air firing,
2. Staged combustion,
3. Flue gas recirculation,
4. Low NO_x burners, and
5. Ammonia injection.

Most of these techniques are not applicable to bagasse- and bagasse residue-fired boilers. Low NO_x burners cannot be used when burning material such as bagasse or residue in a spreader-stoker or moving-grate boiler. Excess air, typically in the range of 30 to 50 percent for these boilers, is required to aid in drying of the moisture-laden carbonaceous material and to ensure complete combustion. The low combustion temperatures encountered in bagasse- and residue-fired boilers inherently limit potential NO_x formation. The subsequent low emission rates, which have been measured as almost insignificant for a bagasse boiler (Peters, 1980), are presented in the emission estimates section of this application.

Based upon the above considerations, good firing and operational practices are considered to be best practical technology in reducing NO_x emissions. Therefore, no other technologies were considered further.

BACT SELECTION

PARTICULATE REMOVAL SYSTEM

On the basis of environmental, energy, and economic impacts, the Joy Turbulaire impingement scrubber was selected as BACT for the proposed boiler. This system is well demonstrated on existing bagasse- and residue-fired boilers in the industry, has a proven operational record with high reliability and low maintenance, and displays low-energy requirements (ΔP = 5 to 9 inches H_2O). The proposed scrubber will operate with a pressure drop of between 5 and 9 inches H_2O, which is the range recommended by the manufacturer. Above this range, increased wear, increased particulate entrainment, and increased fan capacity and horsepower reduce the effectiveness of the system.

A venturi scrubber was not chosen for BACT because it has not proven to be a more efficient control device than the impingement scrubber, which is considerably less expensive to install and operate. It requires a greater pressure drop (2 to 3 times that of the impingement scrubber), with a correspondingly greater energy consumption. It requires more water, and has higher maintenance costs due to the abrasive nature of the fly ash and high gas velocities encountered in the venturi and across the exhaust fan. In addition, venturis must be preceded by mechanical collectors to reduce wear, which further increases capital and operating costs of the system.

Venturi scrubbers have now been installed on a total of six boilers in the Florida industry. Table D-1 summarizes annual compliance tests for the scrubbers. At both Gulf & Western and Talisman, mechanical cyclone collectors precede the venturi scrubbers in order to remove larger particles. At Gulf & Western, the venturi scrubber typically operates at a pressure drop of 16 inches H_2O. At Talisman, the venturis operate typically at 14 inches H_2O pressure drop. As shown, test results have varied widely, ranging from 0.09 lb/MM Btu to 0.30 lb/MM Btu. The average of all tests for all boilers is 0.20 lb/MM Btu. Boiler 6 at Talisman has displayed below average test results, ranging from 0.09 to 0.15 lb/MM Btu. However, emissions from Boiler 6 have gradually worsened throughout the years, possibly reflecting wear of the scrubber. The data show that overall the venturi scrubbers have not achieved a greater degree of emission reduction than that achieved with the impingement scrubber.

Fabric filters and ESPs were rejected for BACT since, to date, they have not been applied in the sugar industry, in other states or in Florida. Pilot-plant testing would be needed before the feasibility of full-scale

Table D-1. Florida Sugar Industry Venturi Scrubber Compliance Tests

		lb/hr Particulate Allowable	lb/hr Particulate Actual	lb/10^6 Btu
Glades County Sugar Cooperative*				
	74-75	32.1	12.4	0.12
	75-76	73.0	45.1	0.19
	76-77	51.2	24.8	0.15
Gulf & Western				
#10	79-80	39.2	43.1	0.22
#11†	79-80	45.1	35.4	0.16
#10	80-81**	46.2	31.2	0.14
#11†	80-81	51.1	53.0	0.21
#11†	Retest	47.7	34.7	0.15
Talisman				
#4	1-6-76	61.5	58.0	0.28
#5	1-6-76	63.5	56.9	0.27
#6†	1-26-76	73.5	31.5	0.09
#4	2-2-77	61.2	54.4	0.27
#5	2-25-77	50.7	43.7	0.26
#6†	Not operating	--	--	--
#4	1-25-78	66.6	64.6	0.29
#5	1-20-78	38.3	38.0	0.30
#6†	1-27-78	86.0	45.2	0.11
#4	12-18-78	44.7	25.7	0.17
#5	12-20-78	44.2	38.6	0.26
#6†	1-3-79	72.7	43.9	0.12
#4	2-13-80	56.0	49.6	0.27
#5	2-7-80	59.0	46.8	0.24
#6†	2-11-80	84.6	59.3	0.14
#4	1-28-81	59.1	42.7	0.22
#5	2-2-81	57.3	52.4	0.27
#6†	2-4-81	80.2	61.2	0.15

* Plant average.
† Allowables are 0.2 lb/10^6 Btu, all others are 0.3 lb/10^6 Btu.
** Modified to vertical orientation this season, #11 remains horizontal.

Source: ESE, 1981.

application of ESP could be assessed. In addition, both ESP and fabric filters exhibit fire and explosion potential and would require dry fly-ash handling and disposal systems, therefore necessitating additional expenditures. A wet fly-ash handling system is already in operation at SCGC, where it serves the existing boilers. A new scrubber could easily be integrated into this existing system.

An economic analysis was conducted on four alternative particulate removal systems: an ESP, fabric filter, venturi scrubber with 14-inch pressure drop preceded by mechanical collectors, and a Turbulaire impingement scrubber with 6-inch pressure drop. Tables D-2 and D-3 summarize the results. As shown, the fabric filter and impingement scrubber both provide similar cost effectiveness. The efficiencies of the ESP and fabric filter could possibly be greater than 91 percent overall, thereby increasing their cost effectiveness. However, since these two systems have not been demonstrated on bagasse/bagasse residue boilers and the cost effectiveness of the ESP is not significantly superior to the impingement scrubber, they were rejected as BACT.

The venturi scrubber, typical of those now in operation in the sugar industry, reflects a cost per unit removal double that of the impingement scrubber. This is primarily due to the need for pretreatment mechanical collectors, larger fan capacity required due to larger pressure drop, and higher operating and maintenance costs. Increased pressure drop across the venturi could afford greater removal efficiencies, but at the expense of increased maintenance and energy requirements.

Because of the superior cost effectiveness of the impingement scrubber, its lower energy requirements, the uncertainty of achieving lower emission levels with the venturi, the small environmental impact of the proposed boiler at the BACT emission level (7-ug/m^3 highest, second-highest 24-hour concentration and about 1-ug/m^3 annual average), and the predicted overall improvement in TSP air quality as a result of the proposed project, the impingement scrubber was chosen as BACT.

Table D-2. Economic Analysis of Alternative Particulate Control Systems ($1,000)

	Electrostatic Precipitator	Fabric Filter	Venturi Scrubber ΔP = 14 in. w/Mech. Collector	Turbulaire Impingement Scrubber ΔP = 6 in.
Capital Costs				
1. Direct Costs				
A. Purchased Equipment				
1. Control Device and Auxiliary Equipment*	572.6	771.9	997.4	496.6
2. Instrument, Controls, Taxes, Freight (A.1 X 0.18)	103.1	138.9	179.5	89.4
TOTAL	675.7	910.8	1,176.9	586.0
B. Installation Direct Costs				
1. Foundations, supports, erection, handling, electrical, piping, insulation, painting†	452.7	655.8	659.1	328.2
2. Indirect Costs				
A. Installation Indirect Costs				
1. Engineering, supervision, construction, field expense, construction fee, startup, testing, contingencies	385.1	409.9	411.9	205.1
TOTAL CAPITAL COSTS (1A + 1B + 2A)	1,513.5	1,976.5	2,247.9	1,119.3

Table D-2. Economic Analysis of Alternative Particulate Control Systems ($1,000)
(Continued, Page 2 of 2)

	Electrostatic Precipitator	Fabric Filter	Venturi Scrubber ΔP = 14 in. w/Mech. Collector	Turbulaire Impingement Scrubber ΔP = 6 in.
Annual Operating Costs				
1. Direct Operating Costs				
A. Operating Labor**				
1. Operator	5.3	12.7	21.2	8.5
2. Supervisor	0.8	1.9	3.2	1.3
B. Maintenance**				
1. Labor	3.5	7.0	7.0	4.7
2. Material	3.5	7.0	7.0	4.7
C. Utilities**				
1. Electricity	31.2	65.3	214.6	93.3
2. Water	--	--	74.5	44.7
D. Waste Disposal	16.5	16.5	16.5	16.5
2. Indirect Operating Costs				
A. Overhead	7.7	17.3	25.1	11.6
B. Property tax, insurance, administration	60.5	79.1	89.9	44.8
C. Capital recovery cost	246.3	321.7	365.8	182.2
TOTAL ANNUAL OPERATING COSTS	375.3	528.5	824.8	412.3

* Does not include stack.
† Does not include site preparation, facilities, and buildings.
** Based upon 24-hr/day, 180-day/yr operation.

Source: ESE, 1981.

Table D-3. Comparison of Cost Effectivenss of Alternative Particulate Control Systems

	Electrostatic Precipitator	Fabric Filter	Venturi Scrubber ΔP = 14 in. w/Mech. Collector	Turbulaire Impingement Scrubber ΔP = 6 in.
Total Annual Costs ($1,000)	375.3	528.5	824.8	412.3
Particulate Removal Efficiency	91%	91%	91%	91%
Tons/Yr Controlled*	3,723	3,723	3,723	3,723
Cost Effectiveness ($/ton Pollutant Controlled)	100.8	142.0	221.5	110.7

* Based on proposed boiler emitting 4,091 tons/yr of uncontrolled particulate (reference Section III.C).

Source: ESE, 1981.

PARTICULATE EMISSION LIMIT

An appropriate emission limit for particulate matter was determined by a source-specific analysis of impingement scrubber performance at SCGC. This analysis is consistent with the case-by-case determination implicit in the definition of BACT. Summarized in Table D-4 are all past particulate emissions test data for the SCGC boilers. Both individual stack tests and compliance test averages are shown. Boilers 1 and 2 are the smallest residue-burning boilers in terms of steam production. Boiler 3 fires bagasse and oil only; the others were all tested while firing residue and oil. Boiler 4 is identical in size to the proposed boiler (240,000 lbs steam/hr).

Individual tests over all boilers have ranged from 0.07 lb/MM Btu to 0.23 lb/MM Btu, averaging 0.16 lb/MM Btu (arithmetic mean). Compliance tests over all boilers have ranged from 0.09 to 0.21 lb/MM Btu, averaging 0.16 lb/MM Btu (arithmetic mean). The wide variation in data experienced at this mill and throughout the industry makes it difficult to define an emission limit which can be met 100 percent of the time. In the only BACT determination for bagasse boilers to date (U.S. Sugar Bryant), an emission level being met 80 percent of the time by the existing boilers at Bryant, based upon plant-specific historical operating data, was chosen as BACT (see attached documentation).

In determining a BACT emission level for SCGC's proposed boiler, the U.S. Sugar, Bryant methodology was applied, even though the resulting limit has been demonstrated to be exceeded 20 percent of the time. Figures 1 through 4 show log-probability plots of the emission test data presented in Table D-4 for SCGC, for all boilers (Figures 1 and 2) and for Boiler 4 only (Figures 3 and 4). Both sets of individual test data reflect 80th-percentile levels of 0.20 to 0.21 lb/MM Btu. A figure based on compliance test results is slightly lower, both sets displaying about 0.19 lb/MM Btu emission levels. Based on these site-specific data, an emission limit equal to the State of Florida standard of 0.2-lb/MM Btu heat input from carbonaceous fuel and 0.1-lb/MM Btu heat

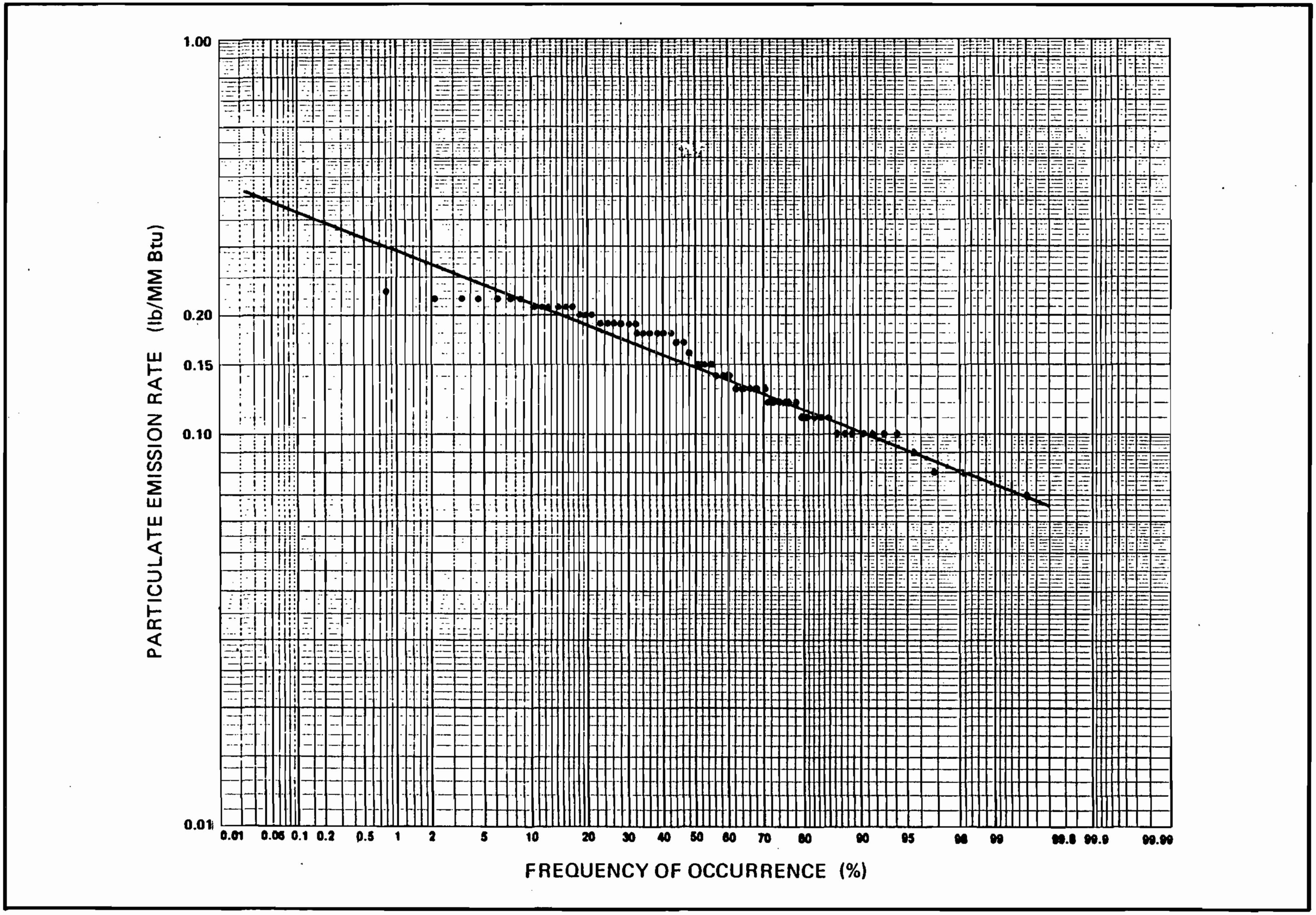
Table D-4. SCGC Particulate Compliance Tests, 1976 to 1981, Impingement Scrubbers in Operation

Boiler	Rated Capacity (lb/steam/hour)	Particulate Emissions by Crop Year (lb/MM Btu)* 1976 to 1977 Individual Tests	1976 to 1977 Test Average	1977 to 1978 Individual Tests	1977 to 1978 Test Average	1978 to 1979 Individual Tests	1978 to 1979 Test Average	1979 to 1980 Individual Tests	1979 to 1980 Test Average	1980 to 1981 Individual Tests	1980 to 1981 Test Average
1	120,000	0.14		0.13		0.16		0.08		0.22	
		0.13	0.13	0.10	0.11	0.16	0.17	0.20	0.13	0.22	0.21
		0.12		0.11		0.18		0.11		0.18	
2	120,000	0.12		0.08		0.17		0.10		0.21	
		0.11	0.12	0.11	0.10	0.15	0.15	0.12	0.10	0.18	0.17
		0.12		0.10		0.14		0.9		0.13	
3†	100,000	0.19		0.19		0.21		0.20		0.19	
		0.15	0.16	0.18	0.16	0.13	0.16	0.22	0.20	0.21	0.20
		0.14		0.12		0.13		0.17		0.21	
4	240,000	0.13		0.22		0.12		0.19**		0.19	
		0.19	0.18	0.18	0.19	0.23	0.15	0.21**	0.19**	0.18	0.19
		0.22		0.17		0.11		0.18**		0.20	
5	160,000	0.15		0.14		0.19		0.10		0.21	
		0.10	0.12	0.13	0.14	0.15	0.17	0.10	0.09	0.19	0.21
		0.10		0.15		0.18		0.07		0.22	

* Adjusted for heat input due to fuel-oil firing by following equation:
[(Actual Emissions − Fuel Oil Allowable) . Heat Input from bagasse or residue].
This method assumes fuel-oil combustion generates 0.1 lb/particulate/MM Btu.
Fuel Oil Allowable = 0.1 times heat input from oil (lb/hr).

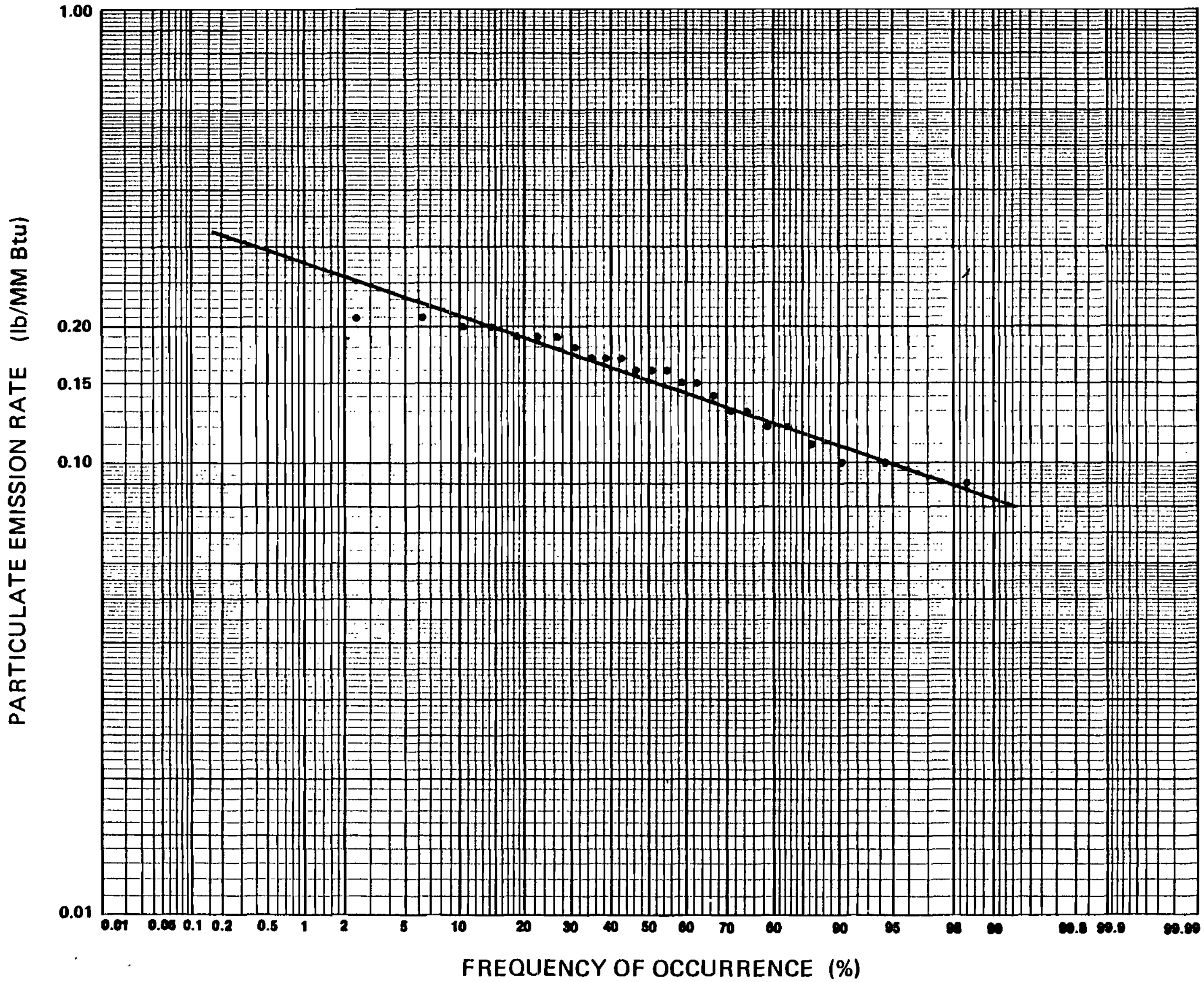
† Bagasse and oil only—all other boilers tested on residue and oil.
**Bagasse and oil only burned during this test.

Source: ESE, 1981.



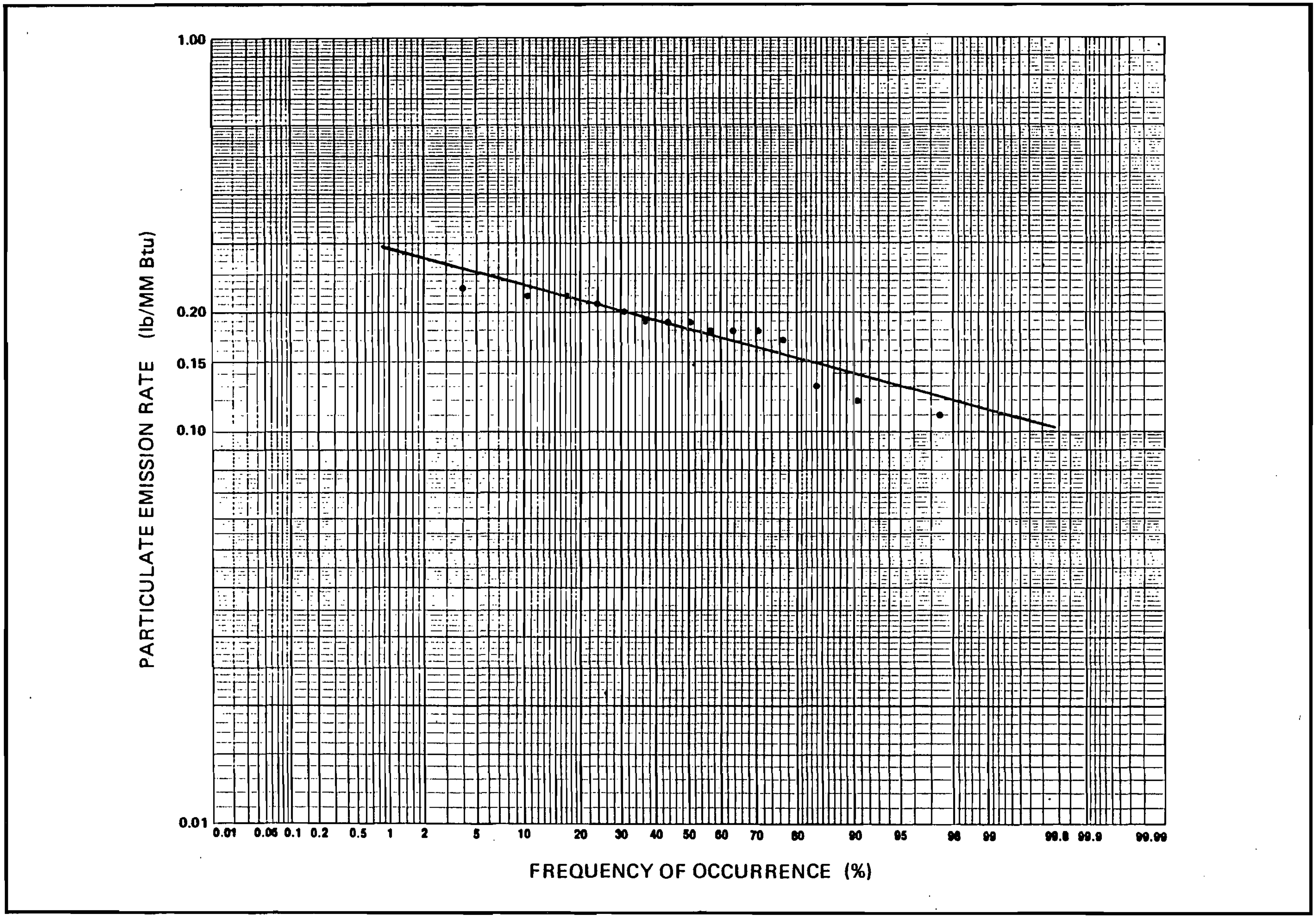
SOURCES: ESE, 1981.
SCGC, 1981.

Figure 1. FREQUENCY DISTRIBUTION OF PARTICULATE STACK TESTS FOR SCGC BOILERS 1 THROUGH 5



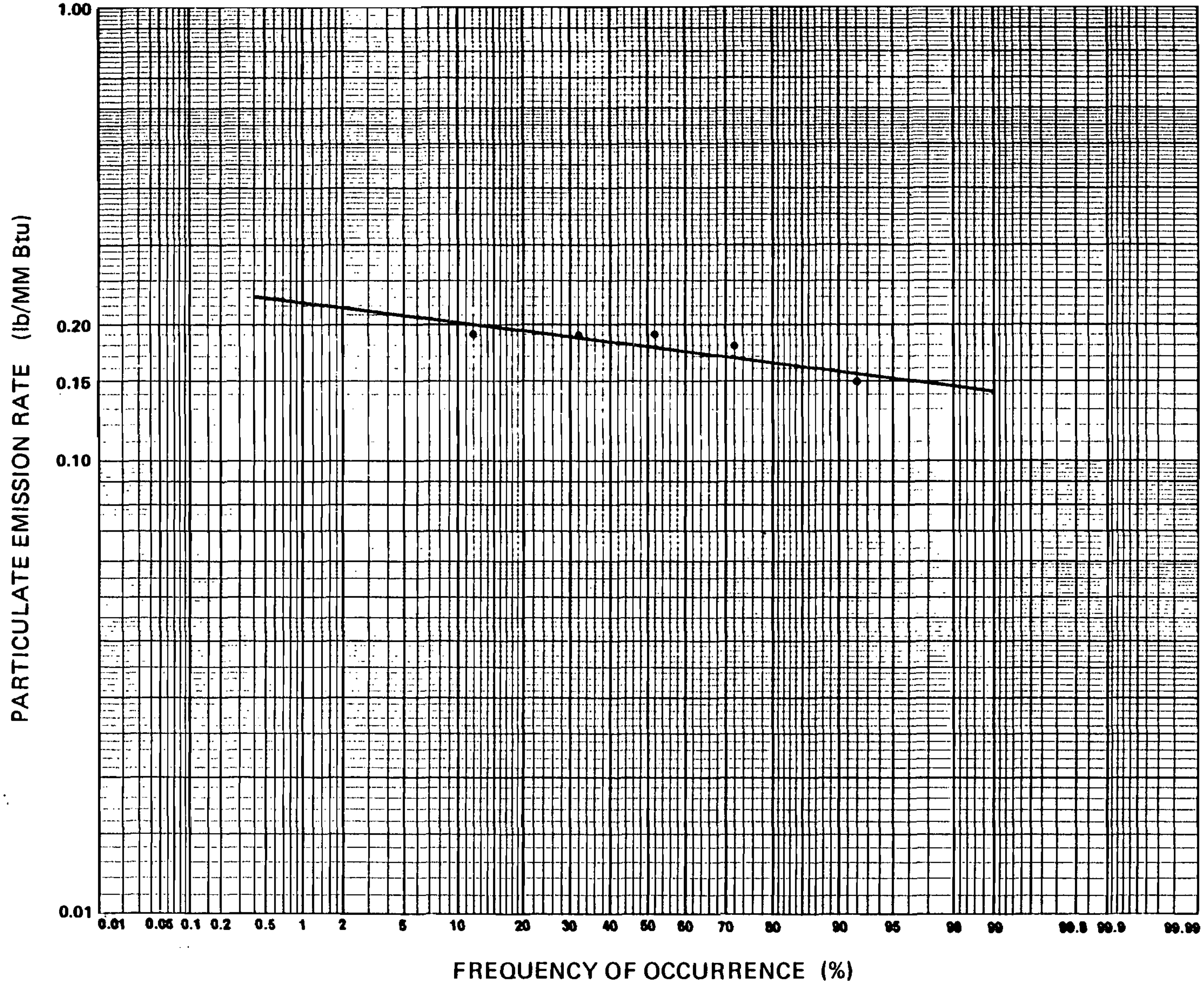
SOURCES: ESE, 1981.
SCGC, 1981.

Figure 2. FREQUENCY DISTRIBUTION OF PARTICULATE COMPLIANCE TESTS FOR SCGC BOILERS 1 THROUGH 5



SOURCES: ESE, 1981.
SCGC, 1981.

Figure 3. FREQUENCY DISTRIBUTION OF PARTICULATE STACK TESTS FOR SCGC BOILER 4



SOURCES: ESE, 1981.
SCGC, 1981.

Figure 4. FREQUENCY DISTRIBUTION OF PARTICULATE COMPLIANCE TESTS FOR SCGC BOILER 4

input due to fuel oil is proposed as BACT. This level is exceeded 20 percent of the time by the existing boilers at SCGC. It is also noted that the State of Florida emission regulation of 0.2 lb/MM Btu heat input due to carbonaceous fuel was not based upon demonstrated achievement of this level in practice, but was set as a goal.

The environmental impact of the new boiler at the proposed BACT particulate emission level is small (7 ug/m^3, 24-hour average and about 1-ug/m^3 annual average), representing 19 percent and 5 percent, respectively, of the allowable Class II PSD increments, and 5 percent and 2 percent, respectively, of the ambient air quality standards. In addition, the overall project will result in a net TSP air quality improvement. Therefore, increased controls are not justified on environmental grounds.

SO_2 CONTROL SYSTEM

Six SO_2 removal system alternatives were evaluated: the Turbulaire impingement scrubber and five add-on SO_2 scrubber systems. The Turbulaire impingement system was chosen as BACT based upon its excellent removal efficiency, at least 40 percent overall for the combustion and scrubbing process, at no additional cost. Add-on scrubbers represent a substantial investment in capital, as well as substantial operating costs and waste disposal problems.

In order to determine costs for add-on flue gas desulfurization (FGD) control systems for SO_2 removal, the publication entitled "Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization" (EPA-600/7-79-178i, Nov. 1979) was utilized. This report presents a summary of capital and annual costs for five FGD systems that were determined to be the best systems for application to industrial boilers (Section 4.0 of the document). A scenario of 0.6-percent S coal and 90-percent SO_2 removal was chosen for comparison for the SCGC proposed addition, since 90-percent removal represents a significantly greater degree of emission control compared to the 40-percent removal inherent in the impingement scrubber and the 0.6-percent S coal is representative of the relatively low SO_2 emissions produced from the proposed bagasse/bagasse residue-fired boiler. If an add-on FGD system is chosen for SCGC, there would be no reason to design it for a low 75-percent removal.

For certain FGD processes, data presented in the document were for various boiler sizes--in many cases not exceeding 200 MM Btu/hr. The proposed boiler size is 500 MM Btu/hr based upon the worst-case fuel burned. In cases where data were presented for boiler sizes of 250 MM Btu/hr and less, the data were extrapolated to a size of 250 MM Btu/hr and multiplied by 1.5, since costs for a system twice the capacity would not be double. Where cost data were available for boiler sizes greater than 250 MM Btu/hr, a linear interpolation to 500 MM Btu/hr was utilized. Costs presented were mid-1978 dollars; therefore, these were adjusted for mid-1981 dollars assuming a 10-percent annual increase.

The results of the FGD economic analysis are presented in Table D-5. The Turbulaire impingement scrubber, with inherent 40-percent SO_2 removal, affords essentially free SO_2 removal since no additional capital investment or annualized costs are required beyond the particulate control device. All of the add-on FGD systems have a very high cost per unit removal due to the large capital investments and operating costs associated with these systems. The impingement scrubber will control approximately 540 tons/year of SO_2. The add-on FGD systems will control approximately 740 additional tons of SO_2 per year. However, this additional control is at an extremely high economic penalty.

SO_2 Emission Limit

The SO_2 BACT emission limit is proposed in terms of lb/MM Btu for each fuel type utilized, which is consistent with the manner in which the particulate BACT emission limits (and Florida emission standards)

Table D-5. Economic Analysis and Cost Effectiveness of Alternative SO_2 Control Systems

	Control System					
	Turbulaire Impingement Scrubber*	Lime/ Limestone Scrubbing	Sodium Throwaway Scrubbing	Double Alkali Scrubbing	Spray Drying	Wellman-Lord Process
Total Capital Cost ($1,000)	0	2,252	1,694	1,984	3,625	4,459
Total Annualized Costs ($1,000)	0	1,189	950	1,000	1,575	1,446
SO_2 Removal Efficiency (%)	38†	90	90	90	90	90
Tons/Yr Controlled**	538	1,274	1,274	1,274	1,274	1,274
Cost Effectiveness ($/ton pollutant controlled)	0	933	746	746	1,236	1,135

* Costs represent those above that required for the particulate removal system.
† Based upon 40-percent removal for bagasse and bagasse residue and zero removal for oil burning.
** Based upon proposed boiler emitting 1,415 tons/yr of uncontrolled SO_2 (reference Section III.C).

Source: ESE, 1981.

are expressed. This is also consistent with the manner in which the BACT emission limits of the U.S. Sugar, Bryant new boiler are expressed. The lb/MM Btu terminology allows easy calculation of the allowable emission limit for any combination of fuels being burned in the proposed boiler.

The proposed SO_2 emission limits are:

0.15-lb/MM Btu heat input due to bagasse
0.54-lb/MM Btu heat input due to bagasse residue
2.10-lb/MM Btu heat input due to fuel oil.

These limits are based upon the design fuels for the proposed boiler, with residue containing 0.4-percent sulfur, bagasse containing 0.1-percent sulfur, and 40-percent SO_2 loss when burning these fuels.

The oil limit is based upon maximum of 1.8-percent sulfur fuel being burned in the proposed boiler, assuming no SO_2 removal in the scrubber. The oil purchased for the proposed boiler will actually be of 1.0-percent sulfur content (equivalent to 1.2 lb/MM Btu). However, in order for the present practice of mixing low sulfur and high sulfur fuel oil together at SCGC mill to continue, thus avoiding an expensive additional fuel oil storage tank and associated piping, pumps, and metering devices, the additional low sulfur (1.0-percent fuel oil) purchased for the new boiler will be mixed with the low and high sulfur oil now purchased and mixed for the existing boilers. During 1980, the average fuel sulfur content utilized at SCGC was 1.8 percent. With the additional 1.0-percent sulfur purchases for the new boiler beginning in 1982, the average should be lower than 1.8 percent. Therefore, a maximum emission limit of 2.10 lb/MM Btu when burning fuel oil, equivalent to 1.8-percent sulfur fuel, is proposed as BACT.

The fuel oil purchased for the proposed boiler will be of 1.0-percent sulfur content, as described above. A lower sulfur content oil (i.e., 0.6-percent S) would generate no less SO_2 per lb of steam produced than will be generated burning bagasse residue in the proposed boiler. Since fuel oil is costly compared to bagasse or bagasse residue, the two carbonaceous fuels will be burned in preference to fuel oil whenever they are available. As a result, there is no incentive to require 0.6-percent S or lower fuel oil for BACT. In addition, based upon anticipated fuel usage in the new boiler (see Table A-3, PSD report), the incremental increase in SO_2 emissions from utilizing 1.0-percent sulfur oil compared to 0.6-percent sulfur oil is only 15 tons per year, which is not significant compared to the total annual projected SO_2 emissions from the boiler.

The environmental impact of the proposed boiler at the proposed BACT emission limits further justifies the BACT selection. Highest, second-highest predicted 3-hour and 24-hour concentrations due to the proposed boiler only are 51 ug/m^3 and 16 ug/m^3, representing 10 percent and 18 percent, respectively, of the allowable Class II PSD increments, and 4 percent and 6 percent, respectively, of the State of Florida AAQS. In addition, the proposed stack modifications will result in an SO_2 air quality improvement over current operating conditions.

ATTACHMENT E

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

CONSTRUCTION PERMIT

FOR U. S. Sugar Corporation
P. O. Drawer 1207
Clewiston, Florida 33440

PERMIT NO. AC50-5177 DATE OF ISSUE 9-20-78

PURSUANT TO THE PROVISIONS OF SECTIONS 403.061 (16) AND 403.707 OF CHAPTER 403 FLORIDA STATUTES AND CHAPTERS 17-4 AND 17-7 FLORIDA ADMINISTRATIVE CODE, THIS PERMIT IS ISSUED TO:

Mr. A. R. Mayo, Vice President

FOR THE CONSTRUCTION OF THE FOLLOWING:

Boiler #5; Design steam production rate of 250,000 lbs/hr; Fired with bagasse and supplemental No. 6 fuel oil; Controlled by one Joy Turbulaire, Size 175, Type D, impingement scrubber.

LOCATED AT Bryant Sugar Mill, U. S. Route 98, Bryant, Palm Beach County UTM: East 537.7 North 2969.1

IN ACCORDANCE WITH THE APPLICATION DATED May 3, 1978

ANY CONDITIONS OR PROVISOS WHICH ARE ATTACHED HERETO ARE INCORPORATED INTO AND MADE A PART OF THIS PERMIT AS THOUGH FULLY SET FORTH HEREIN. FAILURE TO COMPLY WITH SAID CONDITIONS OR PROVISOS SHALL CONSTITUTE A VIOLATION OF THIS PERMIT AND SHALL SUBJECT THE APPLICANT TO SUCH CIVIL AND CRIMINAL PENALTIES AS PROVIDED BY LAW.

THIS PERMIT SHALL BE EFFECTIVE FROM THE DATE OF ISSUE UNTIL 9-20-80 OR UNLESS REVOKED OR SURRENDERED AND SHALL BE SUBJECT TO ALL LAWS OF THE STATE AND THE RULES AND REGULATIONS OF THE DEPARTMENT.

Philip R. Edwards
Philip R. Edwards
District Manager

J W Landers Jr
JOSEPH W. LANDERS, JR.
SECRETARY

DER Form PERM 11-1 (Mar. 76)

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

CONSTRUCTION PERMIT PROVISOS

AIR POLLUTION SOURCES

Permit No. AC50-5177 Date: 9-20-78

(X) 10. The allowable emission rates for this boiler are as follows:

(a) Particulate Matter: 0.130 pounds per million BTU's heat input for carbonaceous fuel, plus 0.10 pounds per million BTU's heat input for fossil fuel.

(b) Sulfur Dioxide: 0.80 pounds per million BTU's heat input for fossil fuel.

(c) Visible Emissions: Shall not exceed Ringleman Number 1.5 or an opacity of 30 percent, except that a density of Ringleman Number 2 or an opacity of 40 percent is permissible for not more than two minutes in any one hour.

X) 11. This permit is issued conditioned upon U.S. Sugar Corporation accepting permit modifications to the existing bagasse fired boilers at the Bryant Mill. These permit modifications would restrict particulate emissions to 0.247 pounds per million BTU's heat input.

X) 12. Ambient monitoring for particulate matter shall be conducted for the first operating season that the new boiler #5 is in operation. The location of the sampler shall be in the approximate area of expected maximum 24-hour ambient concentrations based upon the modeling study for this plant. Sampling shall be conducted using EPA reference methods. A program for monitoring indicating location, frequency, methods of collection and analysis, and quality assurance procedures shall be submitted to the Department within ninety (90) days of receipt of this permit. This program shall be subject to Department approval.

2180 WEST FIRST STREET
SUITE 401
FORT MYERS, FLORIDA 33901

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

PHILIP R. EDWARDS
DISTRICT MANAGER

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

SOUTH FLORIDA DISTRICT

August 15, 1979

CERTIFIED MAIL #4095925

Mr. A.R. Mayo
Vice President
U.S. Sugar Corporation
P.O. Drawer 1207
Clewiston, Fl. 33440

Re: Palm Beach Co - AP
US Sugar Corp.
Boiler #5
AC50-5177

Dear Mr. Mayo:

In response to the stipulation entered into between the Department and U.S. Sugar Corporation, Construction Permit AC50-5177 is modified as follows:

1. Condition #10: The allowable emission rates for this boiler are as follows:

    a. Particulate Matter: 0.150 pounds per million BTU's heat input for carbonaceous fuel, plus 0.10 pounds per million BTU's heat input for fossil fuel.

    b. Sulfur Dioxide: Limitation remains as originally issued.

    c. Visible Emissions: Limitations remain as originally issued.

2. Condition #11: The original condition is deleted.

All other conditions remain as originally issued.

Mr. A. R. Mayo
Page 2
August 15, 1979

Should you object to these permit modifications, you may file an appropriate petition for an administrative hearing. This petition must be filed within fourteen (14) days of receipt of this letter and must conform to the requirements of Section 28-5.15, Florida Administrative Code (copy enclosed). The petition must be filed with the Office of General Counsel, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301. If no petition is filed within the prescribed time, you will be deemed to have accepted this permit modification and waived your right to request an administrative hearing on this matter.

Your continued cooperation in this matter will be appreciated.

Sincerely,

Philip R Edwards

Philip R. Edwards
District Manager

Encl

PRE/TWD/hi

cc: Mary Clark
Palm Beach Co Health Dept
William H. Green

B4 PA

environmental science and engineering, inc.
P. O. BOX 13454 • GAINESVILLE, FLORIDA 32604 • 904 / 372-3318

September 11, 1978

Mr. Brian Mitchell
Air Program
EPA Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Brian:

Following our discussion on August 31 regarding the BACT determination for U.S.Sugar Corporation's proposed new bagasse boiler, we have reviewed the information which was submitted and offer additional clarifying information which you requested.

Regarding the use of supplemental fuel oil, Mr. A. R. Mayo, Vice President of U.S.Sugar Corporation, has indicated to us that 150,000 gallons of No. 6 oil per year would meet their normal needs. Thus, the use of oil with a sulfur content of 2.4 percent will result in an emission of substaintally less than 250 tons per year of SO_2.

At our meeting, one of your associates raised the question of insuring that the steam production on oil alone would not exceed 150, 000 pounds of steam per hour. Mr. Mayo has assured us that the design of the boiler precludes this. The total system is designed for the production of no more than 150,000 pounds of steam per hour when burning oil alone. The whole purpose of a bagasse boiler is to utilize the bagasse. The firing sub-system, including guns, piping, pumps, controls, and oil heater limit the steam production to 150,000 pounds of steam per hour on oil alone. Also the boiler, ducts, fans, and controls are designed to limit steam production to this value.

You had asked us to contact Joy Manufacturing, who make the Turbulaire scrubber, to find out if they would guarantee their scrubber to meet an emission limitation of 0.1 lb per million BTU heat input. Mr. Bob Hyde, of Joy, has indicated to us that this would have to be on a case-by-case basis.

ATLANTA, GEORGIA 404 / 688-5029 | JACKSONVILLE, FLORIDA 904 / 398-8803 | ST. LOUIS, MISSOURI 314 / 567-4600 | TAMPA, FLORIDA 813 / 536-6672

We have performed a statistical analysis of the emission test results from U.S.Sugar mills at Bryant and Clewiston. Enclosed are Log-probability plots for results from Bryant alone, and Bryant and Clewiston. The Clewiston boilers which are included are those which are the same manufacturer and which have the same physical configuration of boiler, fan, and scrubber. Figures 1 and 3 are expressed in terms of pounds per million BTU of heat input. Figures 2 and 4 are expressed in terms of grains per dry standard cubic feet of flue gases. If the sampling data may be considered as being representative of the new boiler and scrubber, based on the Bryant data alone, emissions would exceed:

0.18 $lb/10^6$ BTU	10% of the time
0.15 "	20% "
0.10 "	60% "

Using both Bryant and Clewiston data (both under the same management), the emissions would exceed:

0.21 $lb/10^6$ BTU	10% of the time
0.18 "	20% "
0.10 "	76% "

As we indicated to you at the time of our meeting, bagasse is a fuel which is extremely variable in its characteristics. The variability depends upon the variety of cane, the milling method, the soil in which it was grown, the weather conditions during harvest, and other factors beyond the control of the company.

All of the re-evaluation of data which we have performed has led us to the conclusion that BACT for bagasse boilers should be no more stringent than the Florida rule for new sources of 0.2 pound per million BTU of heat input. A lower emission limitation can not be complied with consistently by a company which has one of the best records of emission control in the Florida industry.

We look forward to a thorough discussion of this determination on September 20. If you or your colleagues have any additional questions, please do not hesitate to call me or Dave Buff.

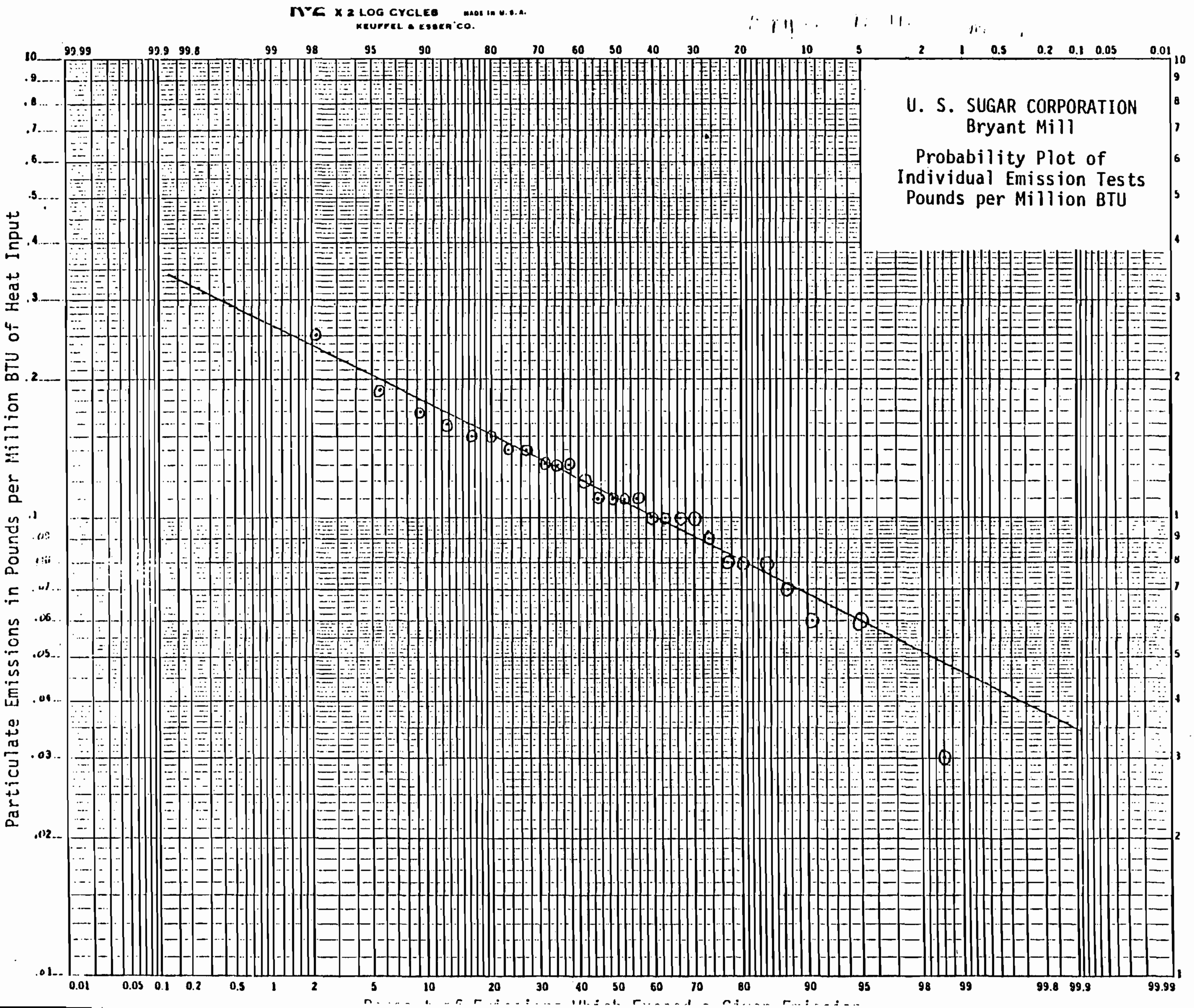
Sincerely yours,

ENVIRONMENTAL SCIENCE & ENGINEERING, INC.

E. R. Hendrickson, Ph.D.,P.E.
Chairman of the Board

ERH/cbh

CC: Mr Mayo
Mr.Green



X 2 LOG CYCLES
KEUFFEL & ESSER CO.
U. S. SUGAR CORPORATION
Bryant Mill
Probability Plot of
Individual Emission Tests
Pounds per Million BTU
Particulate Emissions in Pounds per Million BTU of Heat Input

April 7, 1981

Mr. Thomas W. Davis, Engineer
Department of Environmental Regulation
2269 Bay Street
Fort Myers, Florida 33901

RE: Palm Beach County - USSC
Bryant Boiler No. 5

Dear Mr. Davis:

As you requested we are enclosing copy of Report No. 352-S, the first compliance tests performed on Bryant Boiler No. 5 for the 1980/81 Crop and which was repeated on March 6, 1981, Report No. 355-S, because it failed to meet the 0.15#/MBTU limit established for this Boiler. We have already submitted the second tests which I understand you witnessed and which did meet the emission limit.

As you know, the emission limits placed on this Boiler by DER were based on a BACT determination which concluded that BACT for this Boiler was in fact an emission control installation similar to the other existing Boilers at Bryant Mill, yet the limit was arbitrarily set at 0.15#/MBTU. This was done despite the fact that as we pointed out to your Department at the time, these existing Boilers, although capable as an average of meeting this limit, the test data for these Boilers showed that they did with certain frequency exceed the figure of 0.15#/MBTU. It is to be expected therefore, that the same thing will occur on Boiler No. 5 since both the Boiler and emission control equipment are of the same design as those of the other Boilers in this Plant and which were the basis for BACT for the new Boiler.

As you know, bagasse is a fuel that lacks uniformity in combustibility as compared with other fuels and this results in variations in emissions beyond the control of the owner/operator. This, DER failed to take into consideration despite the data presented to them at the time which showed that the limit established would on occasion be exceeded.

We did enter into a stipulation with DER on July 17, 1979, where Paragraph No. 3 specifically states that the 0.15#/MBTU limit will not prejudice U. S. Sugar's right to seek a modification of the condition at a later date if actual data supported it.

RECEIVED
E.R.A.
APR 13 1981

Such request for modification is not being considered yet in view of the fact that only three full tests have been carried out so far on this Boiler, but if future tests indicate that we cannot with considerable consistency meet the limits as now established we expect to exercise, sometime in the future, the right to seek a modification of these limits.

Very truly yours,

UNITED STATES SUGAR CORPORATION

A. R. Mayo
Vice President, Sugar Houses

ARM/cbb
Enclosure

cc: Mr. Steve Smallwood, Chief
Bureau of Air Quality Management (DER)

Ms. Mary L. Clark, Esquire, DER

Mr. William H. Green, Esquire
(Hopping Boyd Green & Sams)
Tallahassee, FL 32301

ATTACHMENT F

SOURCE TEST REPORT

SULFUR DIOXIDE EMISSIONS
BOILERS 1, 2, and 4
BAGASSE RESIDUE FUEL

Prepared for:

SUGAR CANE GROWERS COOPERATIVE
Belle Glade, Florida

Prepared by:

ENVIRONMENTAL SCIENCE AND ENGINEERING, INC.
Gainesville, Florida

ESE No. 81-127-100

April 1981

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1.0 INTRODUCTION

ESE conducted testing for sulfur dioxide (SO_2) emissions from Boilers 1, 2, and 4 at the Sugar Cane Growers Cooperative in Belle Glade, Florida. These tests were conducted to demonstrate the removal efficiency for SO_2 between combustion and final wet scrubber emissions.

Three test runs were made at each scrubber outlet stack. Boilers 1 and 2 each have dual scrubber/outlet stacks. Boiler 4 has three wet scrubbers and outlet stacks. All outlets were sampled simultaneously using the EPA Method 6 sampling train. Velocity and moisture were measured throughout the testing periods. Steam rates were recorded so that residue feed rates could be established. Residue samples also were taken every half hour during testing and composited for sulfur analysis.

Scrubber inlet concentrations of SO_2 also were measured simultaneously with outlet emissions for Boiler 2.

2.0 SUMMARY OF RESULTS

Tables 1, 2, and 3 summarize SO_2 emissions from the wet scrubber outlets of Boilers 1, 2, and 4, respectively.

Table 4 summarizes the scrubber inlet tests performed on Boiler 2.

On Run 1, Boiler 1, isopropyl alcohol (ISO) was used in the first impinger. The catch in the ISO on the north and south stacks equaled 1.03 and 1.10 pounds per hour, respectively. ISO was not used during any of the subsequent sampling in order to increase accuracy of stack gas moisture determinations. SO_2 removal efficiencies determined in this manner are, therefore, biased in a conservative direction.

Large impingers (EPA Method 8 Type) were used in lieu of midget impingers for all runs; the sample rate was adjusted accordingly.

Complete emission data are presented in Appendix A. Field data sheets are located in Appendix B.

Table 1. Sulfur Reduction Summary, Boiler 1

Boiler Run Number	Date (1981)	Time (Start-Finish)	Flow Rate (SCFMD)	Stack Temperature (°F)	H_2O (%)	Steam Production Rate (lb/hr)	Bagasse Residue S (%)	Bagasse Residue TPH (dry)	SO_2 Emission ppm	SO_2 Emission lb/hr	Reduction Efficiency (%)
Boiler 1 South											
Run 1 S	4/2	1124-1224	20,330	144.2	20.8	—	—	—	82.5	16.66	—
Run 2 S	4/2	1320-1420	20,462	144.6	20.3	—	—	—	102.9	20.91	—
Run 3 S	4/2	1443-1523	20,200	146.6	21.3	—	—	—	112.3	22.53	—
South Average	—	—	20,331	145.1	20.8	—	—	—	99.2	20.03	—
Boiler 1 North											
Run 1 N	4/2	1124-1224	15,742	140.0	19.5	—	—	—	62.5	9.77	—
Run 2 N	4/2	1320-1420	15,889	141.0	20.0	—	—	—	95.1	15.00	—
Run 3 N	4/2	1443-1523	19,018	145.0	21.8	—	—	—	92.5	17.48	—
North Average	—	—	16,883	142.0	20.4	—	—	—	83.4	14.08	—
Total Boiler 1	—	—	37,214	143.6	20.6	120,000	0.414	11.326	91.3	34.11	82

Notes: Residue Feed Rate = $\left(\frac{120{,}000 \text{ lb steam}}{\text{hr}}\right)\left(\frac{1{,}050 \text{ Btu/lb steam}}{0.625}\right) \div \left(\frac{8{,}900 \text{ Btu}}{\text{lb dry residue}}\right)\left(\frac{2{,}000 \text{ lb}}{\text{ton}}\right) = \frac{11.326 \text{ tons dry residue}}{\text{hr}}$

Theoretical SO_2 Emission = $(11.326 \text{ TPH})(2{,}000 \text{ lb/ton})(0.00414)\left(\frac{64.064}{32.064}\right) = 187.4 \text{ lb/hr}$

Source: ESE, 1981.

Table 2. Sulfur Reduction Summary, Boiler 2

Boiler Run Number	Date (1981)	Time (Start-Finish)	Flow Rate (SCFMD)	Stack Temperature (°F)	H_2O (%)	Steam Production Rate (lb/hr)	Bagasse Residue S (%)	Bagasse Residue TPH (dry)	SO_2 Emission ppm	SO_2 Emission lb/hr	Reduction Efficiency (%)
Boiler 2 South											
Run 1 S	4/3	0912-1012	23,988	139.8	19.4	—	—	—	77.3	18.42	—
Run 2 S	4/3	1040-1140	22,386	150.0	21.2	—	—	—	59.0	13.11	—
Run 3 S	4/3	1225-1325	23,306	150.0	22.8	—	—	—	80.3	18.59	—
South Average	—	—	23,227	146.6	21.1	—	—	—	72.2	16.71	—
Boiler 2 North											
Run 1 N	4/3	0912-1012	29,642	144.6	22.0	—	—	—	155.6	45.79	—
Run 2 N	4/3	1040-1140	30,473	150.0	22.3	—	—	—	132.1	39.99	—
Run 3 N	4/3	1225-1325	35,139	150.0	22.1	—	—	—	136.2	47.54	—
North Average	—	—	31,751	148.2	22.1	—	—	—	141.3	44.44	—
Total Boiler 2	—	—	54,978	147.4	21.6	125,000	0.426	11.798	106.8	61.15	70

Notes: Residue Feed Rate $= \left(\frac{125{,}000 \text{ lb steam}}{\text{hr}}\right)\left(\frac{1{,}050 \text{ Btu/lb steam}}{0.625}\right) \div \left(\frac{8{,}900 \text{ Btu}}{\text{lb dry residue}}\right)\left(\frac{2{,}000 \text{ lb}}{\text{ton}}\right) = \frac{11.798 \text{ tons dry residue}}{\text{hr}}$

Theoretical SO_2 Emission $= (11.798 \text{ TPH})(2{,}000 \text{ lb/ton})(0.00426)\left(\frac{64.064}{32.064}\right) = 200.8 \text{ lb/hr}$

Source: ESE, 1981.

Table 3. Sulfur Reduction Summary, Boiler 4

Boiler Run Number	Date (1981)	Time (Start-Finish)	Flow Rate (SCFMD)	Stack Temperature (°F)	H_2O (%)	Steam Production Rate (lb/hr)	Bagasse Residue S (%)	Bagasse Residue TPH (dry)	SO_2 Emission ppm	SO_2 Emission lb/hr	Reduction Efficiency (%)
Boiler 4 South											
Run 1 S	4/3	1645-1715	26,289	145.0	21.2	—	—	—	101.8	26.59	—
Run 2 S	4/4	0834-0934	27,047	146.4	22.2	—	—	—	148.7	39.93	—
Run 3 S	4/4	0950-1054	28,309	147.5	21.5	—	—	—	152.1	42.76	—
South Average	—	—	27,215	146.3	21.6	—	—	—	134.2	36.43	—
Boiler 2 Center											
Run 1 C	4/3	1645-1715	37,249	150.0	23.4	—	—	—	100.2	37.05	—
Run 2 C	4/4	0834-0934	34,937	147.9	24.5	—	—	—	208.6	72.40	—
Run 3 C	4/4	0950-1035	33,945	145.0	22.2	—	—	—	202.2	68.18	—
Center Average	—	—	35,377	147.6	23.4	—	—	—	170.3	59.21	—
Boiler 4 North											
Run 1 N	4/3	1645-1715	27,002	150.0	23.0	—	—	—	126.4	33.91	—
Run 2 N	4/4	0834-0934	28,573	148.1	24.0	—	—	—	198.4	56.30	—
Run 3 N	4/4	0950-1050	30,781	146.3	22.9	—	—	—	189.2	57.83	—
North Average	—	—	28,785	148.1	23.3	—	—	—	171.3	49.35	—
Total Boiler 4	—	—	91,377	147.3	22.8	240,000	0.435	22.652	158.6	145.00	63

Notes: Residue Feed Rate $= \left(\frac{240{,}000 \text{ lb steam}}{\text{hr}}\right)\left(\frac{1{,}050 \text{ Btu/lb steam}}{0.625}\right) \div \left(\frac{8{,}900 \text{ Btu}}{\text{lb dry residue}}\right)\left(\frac{2{,}000 \text{ lb}}{\text{ton}}\right) = \frac{22.652 \text{ tons dry residue}}{\text{hr}}$

Theoretical SO_2 Emission $= (22.652 \text{ TPH})(2{,}000 \text{ lb/ton})(0.00435)\left(\frac{64.064}{32.064}\right) = 393.75 \text{ lb/hr}$

Source: ESE, 1981.

Table 4. Sulfur Dioxide Summary, Boiler 2 Inlet

Boiler Run Number	Date (1981)	Time (Start-Finish)	Flow Rate (SCFMD)	H_2O (Percent)	SO_2	
					ppm	lb/hr
1	4/3	0930-1030	53,630	13.9	155.9	83.04
2	4/3	1054-1154	52,859	13.7	110.7	58.12
3	4/3	1242-1322	58,445	8.3	133.0	77.21
Average	--	--	54,978	12.0	133.2	72.79

Source: ESE, 1981.

3.0 FIELD AND ANALYTICAL PROCEDURES

3.1 FIELD SAMPLING ASSEMBLY

The sampling and analytical procedures used follow the procedures as outlined in EPA Method 6 in the Code of Federal Regulations, Chapter I, Title 40, Part 60, Appendix A, revised as of July 1, 1980, modified for Greenburg-Smith impingers. The sampling equipment consists of the following:

1. Borosilicate Glass Probe--Fitted with ground glass ball joint and heated to maintain conditions above stack dew point; a plug of glass wool inserted to act as a particulate filter.
2. Impingers--Four impingers. The first is a bubbler charged with 100 ml of 80 percent isopropanol and glass wool packed in the top. The second and third are charged with 100 ml each of 3 percent H_2O_2, and the fourth is charged with a preweighed amount of silica gel. Impingers are preweighed if a moisture determination is to be made.
3. Control Box--Module containing a vacuum gage, a thermometer capable of measuring temperature to within $\pm 5°$, a dry gas meter with an accuracy of ± 2 percent, and valves and related equipment to regulate flow.

A schematic of the sampling train is shown in Figure 1.

Upon arrival at the plant, the control box was checked for leaks, the impingers were charged and connected in line, and the probe was attached. The sampling train was leak-checked at 15 inches mercury for leaks. Care was taken during the release of vacuum to prevent backup of the sampling reagents. Crushed ice was packed around the impingers, and the probe was placed in the stack. The stack was sampled for 20 minutes, and readings were taken every 5 minutes. A flow rate of approximately 0.5 cubic foot per minute was held for the entire sample

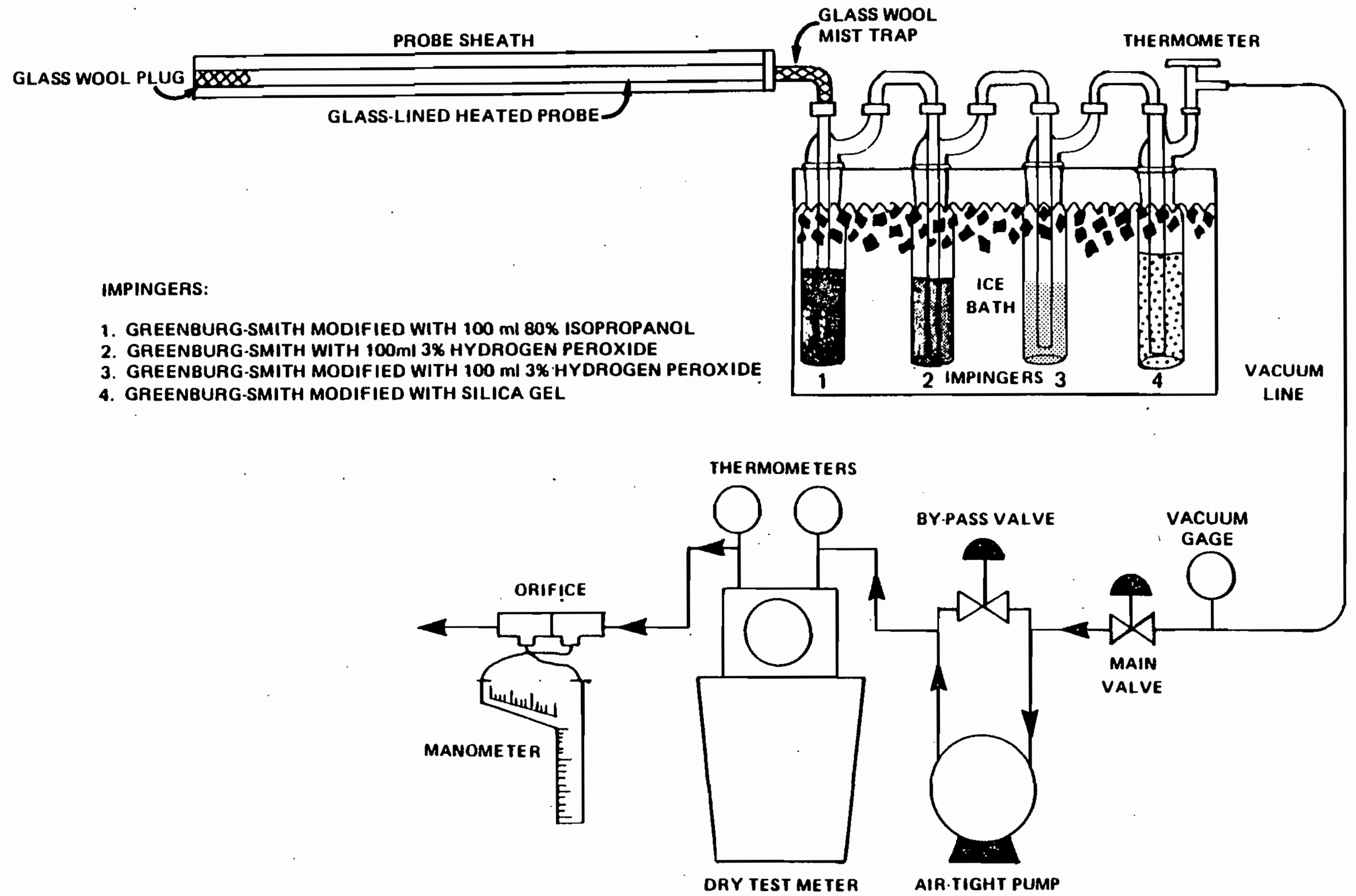

Figure 1
EPA METHOD 6 SAMPLING TRAIN

SOURCE: ESE, 1981.

SUGAR CANE GROWERS COOPERATIVE

period. Upon completion of the run, a final leak check was performed at the highest vacuum encountered during testing.

3.2 SAMPLE RECOVERY

The probe was detached from the train, and the ice bath was drained. Clean ambient air was drawn through the impingers for 15 minutes at the same rate the sample was collected. The impinger train was weighed for moisture gain, and the isopropanol was discarded. H_2O_2 and distilled water washings from the second and third impingers were collected, diluted to 300 ml, and stored in a clean sample bottle for later analysis.

3.3 ANALYTICAL PROCEDURES

The sample was carefully transferred to the laboratory site, and the volume was checked. A 20-ml aliquot was added to 80 ml of 100 percent isopropanol with two to four drops of thorin indicator. The solution was then titrated with 0.0100 N barium perchlorate to a pink endpoint. This was repeated until samples agreed within 1 percent or 0.2 ml.

PREVENTION OF SIGNIFICANT DETERIORATION REPORT

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1.0 SOURCE INFORMATION

The Sugar Cane Growers Cooperative of Florida (SCGC) operates a cane processing mill just outside Belle Glade, Florida (Figure 1). The layout and operation of this mill are described in this section. The plot plan of the sugar processing operation and the process flow are shown in Figures 2 and 3, respectively.

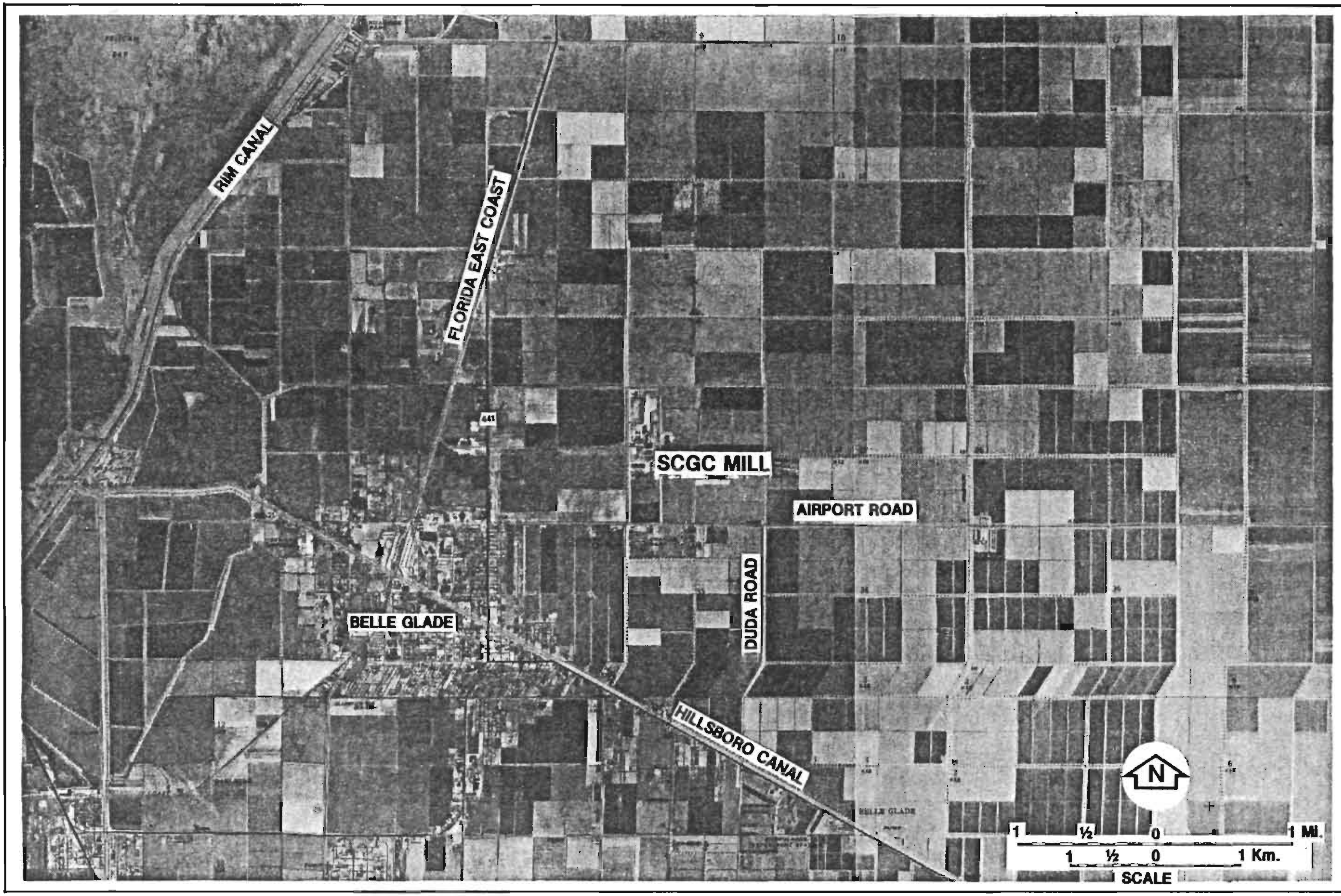
1.1 EXISTING PROCESS

Harvested cane is crushed, and the juice is extracted. The juice is concentrated and separated into sugar crystals and molasses. Most of the bagasse (cane from which the juice has been extracted) is delivered to a neighboring furfural extraction plant. The byproduct of the furfural process is bagasse residue.

Process steam for both the mill and the furfural plant is provided by burning bagasse residue and bagasse; a small amount of oil is burned to supplement steam production and to stabilize boiler operation. The total plant steam generating capacity is 890,000 lb/hr when all boilers are operating at rated capacity.

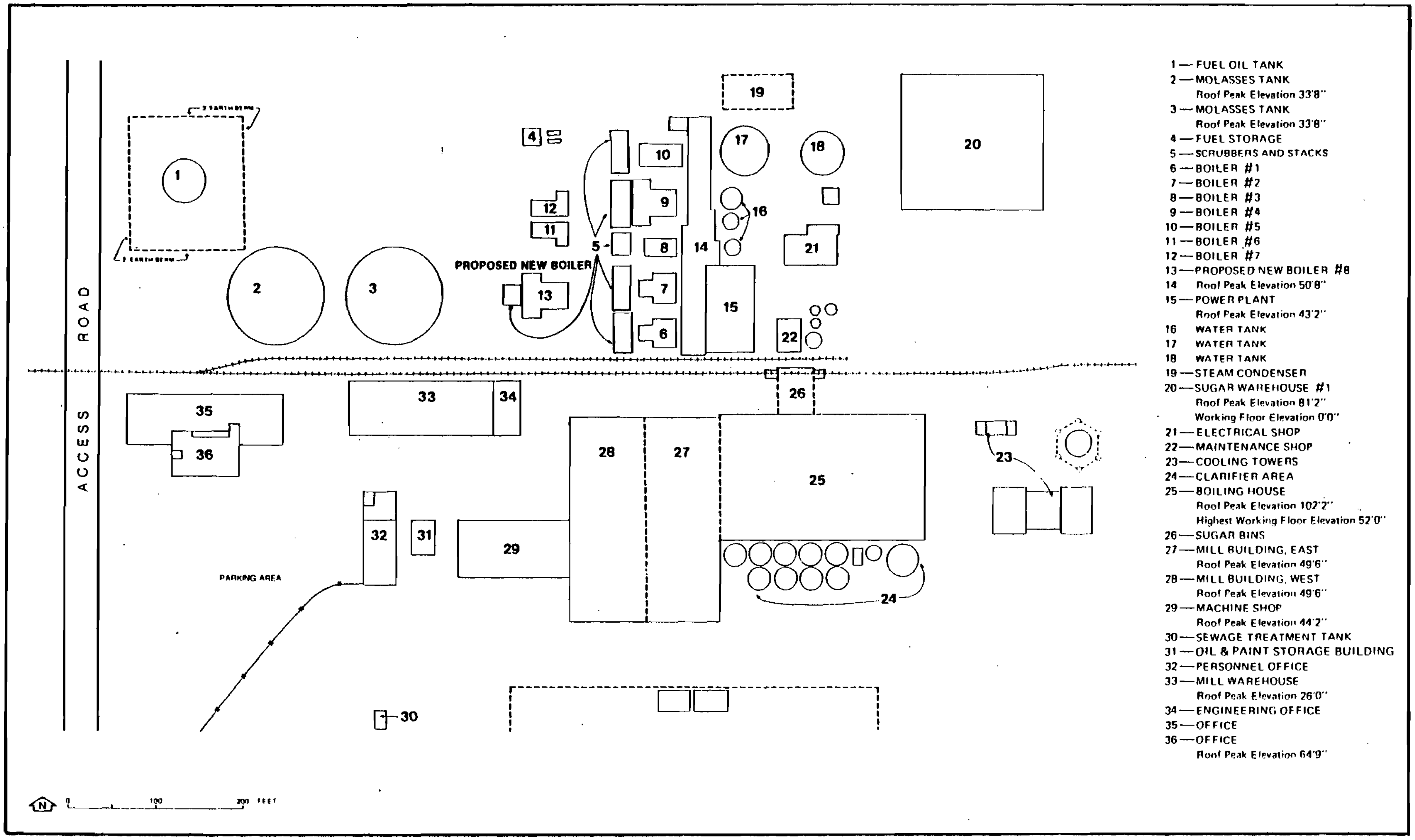
Seven boilers are used during the crop season. Boilers 1, 2, 4, and 5 are capable of burning bagasse, residue, and oil. Boiler 3 burns bagasse and oil only. Boilers 6 and 7 are exclusively oil burning. Boilers 1 through 5 are fitted with a total of 10 impingement scrubbers, with a stack servicing each scrubber. Stack parameters are given in Section 2.2.

Occasionally, during the month preceding and up to 3 months following the crop season, Boilers 1, 2, 4, or 5 are operated to provide steam to the furfural operation. No bagasse is burned during this off-season operation. Steam is produced by burning bagasse residue and oil is used only for start-up and emergencies. Three or fewer boilers are in operation during this period to provide a maximum steam rate of 400,000 lb/hr.



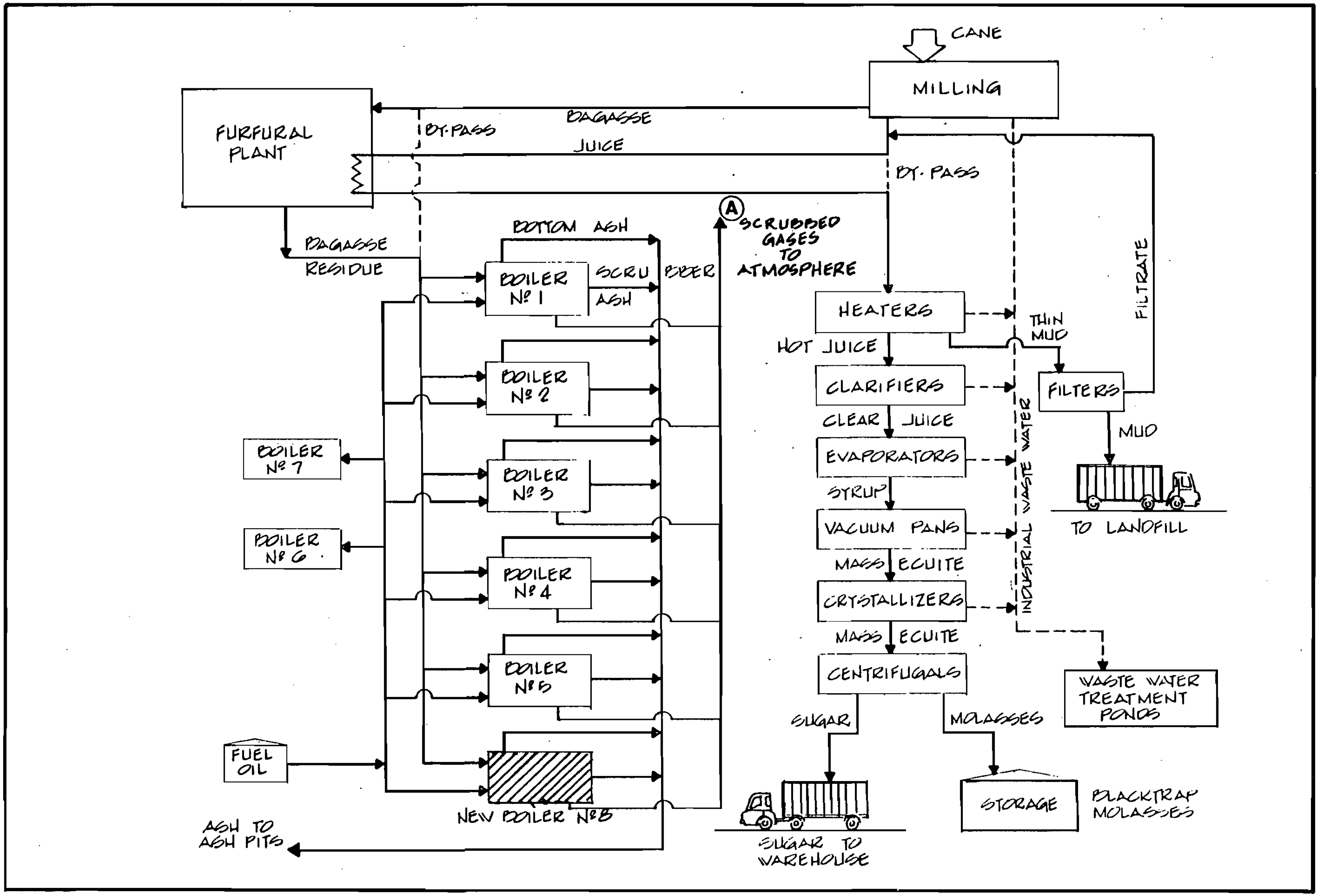
SOURCES: U. S. GEOLOGICAL SURVEY, 1970.
ENVIRONMENTAL SCIENCE AND ENGINEERING, INC., 1981.

Figure 1. LOCATION OF SUGAR CANE GROWERS COOPERATIVE SUGAR MILL



SOURCE: SUGAR CANE GROWERS COOPERATIVE.
ESE, 1981.

Figure 2. PLOT PLAN OF SUGAR CANE GROWERS COOPERATIVE SUGAR MILL



SOURCE: SUGAR CANE GROWERS COOPERATIVE OF FLORIDA.

Figure 3. SUGAR PROCESS BLOCK DIAGRAM

1.2 PROPOSED MODIFICATION

During the next 2 years, an increase in cane planting is expected among members of SCGC. In order to process this cane quickly enough to avoid a degradation of quality in the field, the milling capacity of SCGC Sugar Mill must be increased. To provide steam for this additional capacity, a 240,000 lb/hr, rated capacity, boiler (No. 8) will be built, as shown in Figure 2.

This boiler will have the capability of burning residue, bagasse, and oil. Particulate and sulfur dioxide (SO_2) emissions will be controlled by impingement scrubbing and ducted to a single 155-foot-tall stack. Although Good Engineering Practice (GEP) stack height based on the buildings nearest the new boiler is less than 155 feet, the new stack falls within the area of influence of two buildings with 81- and 102-foot peak elevations. Thus, modeling credit for the 155-foot design stack height is allowed under draft United States Environmental Protection Agency (EPA) Good Engineering Practice Guidelines (EPA, 1978d). More detailed stack parameters are given in Section 2.2.

During the crop season, the projected maximum residue consumption is 1,500 tons per day, distributed among Boilers 1, 2, 4, 5, and 8. The remainder of the steam in Boilers 1 through 5 and 8 is produced from bagasse and the smallest practical amount of oil. Concurrently with this permit, Boilers 6 and 7, rated at 120,000 lb steam/hr, will be limited to production of 75,000 lb steam/hr. Sufficient 1-percent sulfur oil will be purchased to cover the needs of Boilers 6, 7, and 8 and will be blended with the 2.4-percent sulfur oil that supplies the needs of Boilers 1 through 5. The oil burned in all the boilers, therefore, will have a sulfur content somewhere between 1 percent and 2.4 percent. During calendar year 1980, the overall sulfur content of oil in the plant was 1.8 percent. When the additional 1-percent sulfur oil for Boiler 8 is added, the overall sulfur content of oil burned will be less than this amount; however, 1.8-percent sulfur content oil was assumed in the emissions calculations. These calculations are discussed in Section 2.2.

Modeling indicates that improved dispersion of emissions from the existing facilities is necessary to meet ambient air quality standards if the new boiler is added. Thus, in addition to the construction of the new boiler, the following steps will be taken: (1) the three 85-foot stacks serving Boiler 4 will be ducted into a single stack 110 feet tall, (2) the exit gases from Boilers 6 and 7 (currently passing through two 40-foot stacks) will be combined into a single 40-foot stack, (3) permit conditions of the existing boilers will be reduced from 0.3 lb particulate/10^6 Btu to 0.25 lb particulate/10^6 Btu to reflect actual emissions, and (4) Boilers 6 and 7 will each be limited to production of 75,000 lb steam/hr.

The increased buoyancy and initial plume height provided by the stack modifications reduce ground-level concentrations enough to provide a net improvement in air quality, even with the addition of Boiler 8.

2.0 AIR QUALITY ANALYSIS

Current actual total plant emissions of particulate matter, SO_2, and nitrogen oxides (NO_x) are each greater than 250 tons per year; thus, the mill is classified as a major source under both federal and state criteria (40 CFR Part 52.21 and FAC 17-2). The new boiler will increase emissions of these pollutants by an amount greater than the significant rates established by EPA and shown in Table 2-1. Therefore, the addition of Boiler 8 is classified as a major modification and is subject to federal Prevention of Significant Deterioration (PSD) review for these three pollutants. No emission factors for carbon monoxide, hydrocarbons, or non-criteria pollutants are available for bagasse or residue consumption, and emissions of these pollutants have been assumed to be below the federal significant emission rates.

The components of the federal PSD review are:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis,
4. Source information, and
5. Additional impact analysis.

The control technology review is contained in the accompanying permit application. The remaining components are discussed in this PSD report.

Under current Florida Department of Environmental Regulation (DER) PSD rules, the proposed source is a major emitting facility for particulate matter, SO_2, and NO_x, and, therefore, requires PSD review for these pollutants [FAC 17-2.04 (6)(a)]. However, the proposed new boiler and modifications to existing stacks will not cause an increase in ground-level concentrations over the baseline for any pollutant, as is demonstrated in this report; therefore, a Best Available Control Technology (BACT) determination is not required under PSD [FAC 17-2.04 (6)(c)]. Under FAC 17-2.03 Best Available Control Technology, a determination of BACT is required if either required by FAC 17-2.04 (6)(c), or if the proposed source is a major emitting facility and does not have an applicable Emission Limiting Standard in FAC 17-2.05 or 17-2.16. The

Table 2-1. Significant Emission Rates

Pollutant	Significant Emission Rate (Tons per year)
Carbon Monoxide	100
Nitrogen Dioxide	40
Total Suspended Particulates	25
Sulfur Dioxide	40
Ozone (volatile organic compounds)	40
Lead	0.6
Mercury	0.1
Beryllium	0.0004
Asbestos	0.007
Fluorides	3
Sulfuric Acid Mist	7
Vinyl Chloride	1
Total Reduced Sulfur	10
Hydrogen Sulfide	10
Reduced Sulfur Compounds	10
Inorganic Arsenic	0
Radionuclides	0
Benzene	0
Ethylene Dichloride	0
Polyvinyl Chloride	0

Source: Federal Register, Vol. 45, No. 154, 1980.

applicable Emission Limiting Standard for the proposed boiler is for particulate matter only. Therefore, BACT is required for SO_2 and NO_x only under Florida DER rules.

The SCGC Sugar Mill is in Palm Beach County, a non-attainment area for ozone. Since volatile organic compound emissions will not exceed the PSD significant emission rate (Table 2-1) or the non-attainment emission cutoff level of 5 lb/hr and 15 tons/year potential emissions [FAC 17-2.16 (3)(a)], neither non-attainment nor PSD review applies for that pollutant. No sulfur dioxide or particulate matter non-attainment areas are within 100 kilometers (km) of the site.

The nearest Class I area is the Everglades National Park, approximately 105 km south of the plant. Since no Class I areas are within 100 km of the plant, analysis is limited to a discussion of impacts on visibility in Section 3.0.

2.1 MONITORING DATA

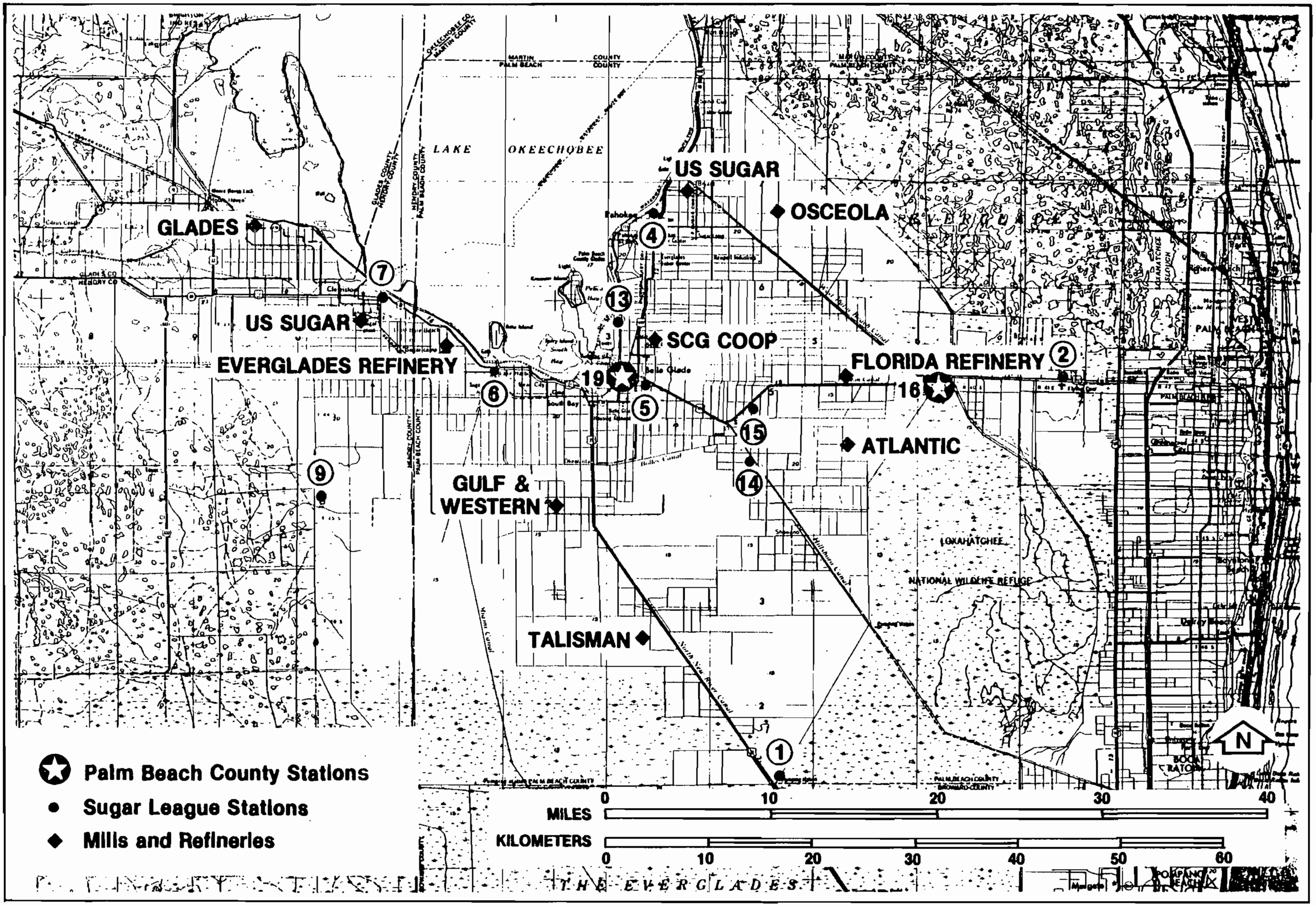
The Clean Air Act Amendments of August 1977 require that the owner of any proposed major air pollution source conduct ambient air monitoring for applicable pollutants for a period of 1 year prior to submission of a construction permit application. The use of existing representative data may be permitted in lieu of monitoring, provided the data meet EPA PSD monitoring criteria. Assuming this application is complete before June 8, 1981, the monitoring provisions of the 1978 PSD regulations will apply. Under these regulations, monitoring was required only for criteria pollutants for which the source was major or a major modification. A major modification was defined as an increase from a new facility within the source of either 100 tons per year (28 listed source categories) or 250 tons per year. Under the old PSD definitions, the proposed modification under the old PSD definitions would be subject to ambient monitoring for SO_2, particulate matter, and NO_x (except that NO_x emissions are only slightly above the PSD threshold and are believed to be greatly overestimated).

2.1.1 Total Suspended Particulate (TSP)

The Florida Sugar Cane League (FSCL) and Palm Beach County (PBC) maintain a network of hi-vol monitors in the sugar producing area of the state. The monitoring is conducted on a 6-day monitoring cycle using the EPA reference method (40 CFR Part 50 App. B). Figure 4 shows the location of these monitors within about 10 miles of the SCGC Sugar Mill, and four additional monitors considered appropriate for determination of a background concentration value. Table 2-2 summarizes the most recently available data from the monitors. No violations of the 150-ug/m^3 24-hour or 60-ug/m^3 annual geometric mean standards have been observed during 1980.

For each station, the concentration one (1) standard deviation above the geometric mean was calculated. For lognormally distributed data, 84 percent of the observed values are below this value. Correlation coefficients for a lognormal fit of the FSCL data are all above 0.990, indicating a very close approximation of the lognormal distribution (correlations not available for PBC stations). Stations 1, 2, 9 and PB16 are greater than 10 km from any point source and yet affected by the same meteorology as the proposed source. As such, they are considered regional monitors, and a statistical analysis of their data was performed to establish a background concentration.

Construction on Highway U.S. 27 near Station 1 began in January 1980 and clearly influenced results at that station during that year. The average 84th-percentile value among the remaining three stations was 40 ug/m^3, which was taken to be an appropriate short-term background concentration. The probability of the 84th-percentile or higher concentration occurring in combination with meteorological conditions causing highest, second-highest 24-hour point source impacts is less than once in 15 years.



SOURCES: FLORIDA SUGAR CANE LEAGUE.
ENVIRONMENTAL SCIENCE AND ENGINEERING, INC., 1981.

Figure 4. REGIONAL HI-VOL MONITORS

Table 2-2. Summary of 1980 Ambient TSP Monitoring Data (24-Hour Average, ug/m^3)

Station*	Number of Observations	Maximum	Second Maximum	Arithmetic Mean	Geometric Mean	Geometric Standard Deviation	Correlation Coefficient	84th Percentile†
SL-1	54	103	79	46	42	1.50	0.979	64
SL-2	57	78	68	30	27	1.55	0.989	42**
SL-4	60	110	89	54	50	1.42	0.983	72
SL-5	58	107	107	64	60	1.40	0.978	85
SL-6	60	115	100	43	39	1.56	0.995	61
SL-7	53	102	83	45	42	1.44	0.968	61
SL-9	56	49	44	24	23	1.45	0.992	32**
SL-13	57	106	92	36	32	1.66	0.969	53
SL-14	60	102	100	40	35	1.65	0.993	58
SL-15	51	105	90	47	43	1.51	0.990	65
PB-16	60	68	67	34	32	1.44	--††	46**
PB-19	61	110	96	59	57	1.34	--††	76

* SL = Sugar League Data
PB = Palm Beach County Data

† $C_{.84} = M\ Sg^{(1-0.5 \text{ in } Sg)}$
$C_{.84}$ = 84th percentile concentration
M = arithmetic mean
Sg = geometric standard deviation (Larson, 1971).

** Background station.

†† Not available from annual report.

Source: ESE, 1981.

2.1.2 Sulfur Dioxide (SO_2)

Continuous SO_2 monitoring was conducted with a Beckman 906A analyzer in combination with selective scrubbers. During 1976 and the first three quarters of 1977, the monitor was located in downtown Belle Glade. The highest 1-hour reading during this period was 257 ug/m^3.

In November of 1977, the monitor was moved to the IFAS Agricultural Research and Education center outside Belle Glade. The data recorded at that location are summarized in Table 2-3. The highest values recorded were 210 ug/m^3 (3-hour), 115 ug/m^3 (24-hour), and 18 ug/m^3 (annual). Monitoring for sulfur dioxide was discontinued in June 1979 because of consistently low readings during the previous 4 years.

The Palm Beach County Health Department operated a continuous SO_2 monitor at the Belle Glade Water Treatment Plant until May 1978. The highest 3-hour and 24-hour averages recorded in 1977 were 76 ug/m^3 and 42 ug/m^3, respectively. The highest 3-hour and 24-hour averages recorded in 1978 before the monitor was discontinued were 113 ug/m^3 and 50 ug/m^3, respectively.

A background concentration of 20 ug/m^3 was assumed for modeling purposes (EPA, 1978a).

2.2 AIR QUALITY IMPACTS

2.2.1 Emissions Inventory

The area within 50 km of SCGC Sugar Mill was inventoried for point sources of particulate and sulfur dioxide emissions. The basis for this inventory was the 1980 Air Permit Inventory System (APIS). Construction permits submitted during 1981 were also accounted for and the maximum allowable emission rates were used.

Table 2-3. Summary of Sulfur Dioxide Monitoring Data, 1978 to 1979, Florida Sugar Cane League

Year	Quarter	Number of Observations	Highest 3-Hour (ug/m^3)	Highest 24-Hour (ug/m^3)	Arithmetic Average (ug/m^3)
1978	1	--	210	115	34
	2	--	47	24	8
	3	1,788	123	55	26
	4	1,762	52	31	13
	Annual	--	--	--	18
1979	1	1,900	52	26	9
	2	1,893	66	45	5
	Year to date	--	--	--	8

Note: Monitor is located at the IFAS Agricultural Research and Educational Center outside the city of Belle Glade.

Source: Florida Sugar Cane League.

The inventory includes all the mills and both refineries in Palm Beach and Hendry Counties, two point sources in Belle Glade, and Florida Power & Light Riviera and Lake Worth Utilities generating stations.

2.2.2 Dispersion Models and Meteorology

Both short-term (3- and 24-hour) and long-term (crop-season) impacts were predicted with the Industrial Source Complex model, an EPA approved gaussian dispersion model, using rural dispersion characteristics.

Five years (1970 to 1974) of historical surface meteorological data recorded at West Palm Beach Airport were input to the model. Upper atmosphere observations were recorded at Miami for the same time period. Only data for the period from 15 October through 15 March were modeled to reflect the seasonal operation of the plant. Plant emissions during the off season will be less than half the maximum emissions. Experience with West Palm meteorological data indicates that worst-case meteorology during the off season produces impacts no more than 20 percent above those projected for the crop season, with equal emissions. The impacts of the off-season reduced loads will not exceed those modeled for full load during the crop season.

2.2.3 Air Quality Impact

Initial modeling with 5 years of meteorological data was performed for emissions from SCGC Sugar Mill only. The critical meteorology and approximate location of highest, second-highest concentrations were determined with a radial receptor grid covering 36 directions every 200 meters from the plant center. The impact determination was refined with a 1-km square grid of receptors at 100-meter intervals. All surrounding sources were included in this refined analysis.

The stack parameters used for modeling are shown in Table 2-4. Calculation of flow rates and pollutant emission rates are found in

Table 2-4. Summary of Stack Parameters

Boiler	Rated Steam Capacity (lb/hr)	Number of Stacks	Stack Height (ft)	Temperature of Exit Gas (°F)	Stack Diameter (ft)	Particulate Worst Case		SO_2 Worst Case	
						10^3 ACFM	lb/hr*	10^3 ACFM	lb/hr*
1	120	2	80	160	4.5	38.6	27	37.2	48
2	120	2	80	160	4.5	38.6	27	37.2	48
3	100	1	80	160	5.3	64.3	45	67.4	35
4 as is	240	3	85	160	5.3	51.4	29	49.7	64
4 w/mod	240	1	110	160	9.2	154.3	86	149.0	192
5	160	2	80	160	4.5	51.5	36	49.5	64
6 as is	120†	1	40	630	5.0	42.9	9.8	42.9	203
7 as is	120†	1	40	630	5.0	42.9	9.8	42.9	203
6 and 7 w/mod	75 each	1	40	630	7.1	85.8	19.6	85.8	406
8	240**	1	155	160	10.0	169.8	95.0	164.0	211

* See Appendix A, Table A-3: as-is emissions based on 0.25 actual for Boilers 1, 2, 3, and 5; 0.2 allowable for Boilers 4 and 8.
† Emissions calculated at actual maximum of 75,000 lb/hr.
** Emissions calculated with 10-percent peak factor.

Source: ESE, 1981.

Appendices A and B. Worst-case impacts for TSP and SO_2 occur under different operating conditions.

Worst-case particulate impact occurs when burning 100-percent bagasse or residue in Boilers 1 through 5 and 8. Even though the emission rate while burning bagasse could be potentially greater than while burning bagasse residue, the buoyant flux of the exit gases is greater. This potential difference is due to variations in moisture content, heating value, combustion efficiency, and required excess air. Since the differences in emissions and buoyant flux would be offsetting, the average value of the two fuels was used.

Worst-case SO_2 impacts occur when the maximum amounts of residue and oil are burned. Total process operation limits available residue to 1,500 tons per day. This amount of residue is divided among Boilers 1, 2, 4, 5, and 8 in a ratio approximately proportional to their rated steam capacity. The remaining required steam is generated from 900 tons/day of bagasse and some oil. When bagasse residue supplies are limited, the steam demand is met by additional bagasse, if available.

Sulfur dioxide modeling was based on maximum plant-wide residue usage of 1,500 tons per day. Projected average daily oil consumption for Boilers 1 through 5 and 8 (5,800 gal/day) and maximum oil consumption for Boilers 6 and 7 (33,300 gal/day) were also assumed. This fuel mix is detailed in Table A-3 in Appendix A. This projected total oil consumption of 39,100 gal/day is 61 percent greater than the actual average daily consumption of 24,250 gal/day during the crop season in 1980. Although oil consumption during any hour may be several times the average rate when bagasse and residue are not available, this occurs only when the plant milling rate is substantially below capacity. Under these conditions, the corresponding steam demand is also reduced and the boilers are operating at a fraction of their rated capacity. Thus, plant-wide SO_2 emissions will never operationally exceed the 14 tons per day projected for the fuel mix described previously.

Above-average oil consumption in Boiler 8 may increase its individual SO_2 emissions above the 211 lb/hr used as model input. This condition would only occur simultaneously with a reduction in SO_2 emissions from the other boilers. Since a greater proportion of emissions would be passing through a taller stack, the ground-level impacts under this condition would not increase over that modeled for the average conditions.

The results of this analysis are given in Table 2-5. The sum of the projected highest, second-highest impacts and background concentrations are 149 ug/m^3 24-hour TSP, 249 ug/m^3 24-hour SO_2, and 492 ug/m^3 3-hour SO_2. These values are below the corresponding Ambient Air Quality Standards (AAQS) of 150 ug/m^3, 260 ug/m^3, and 1,300 ug/m^3, respectively (Table 2-6).

The possibility of interaction with surrounding sources to produce higher concentrations was investigated. The critical meteorology in the directions aligning the nearest sources was determined. Concentrations along this radial with the selected meteorological conditions were determined. Table 2-7 gives the results of this investigation. It is seen that no source interactions occur which produce concentrations more than 2 ug/m^3 higher than those due to SCGC alone. No concentrations above AAQS standards are projected.

The projected average concentrations due to SCGC Sugar Mill emissions after plant modification over the 184-day modeling period were 13 ug/m^3 TSP and 25 ug/m^3 SO_2; during the rest of the year the plant is operating at less than half capacity or is totally inoperative. Thus, the actual annual average will be some fraction of these 184-day averages. The 184-day averages determined in the same way for the existing plant are 16 ug/m^3 TSP and 40 ug/m^3 SO_2 (Table 2-5). Since no violations of the annual standards were detected in 1980 at any monitoring site and the proposed construction will result in a net air

Table 2-5. Highest, Second-Highest Ground-Level Concentrations (ug/m^3)--Proposed SCGC Sugar Mill Expansion.

	TSP		SO_2		
	24-hr	184-day	3-hr	24-hr	184-day
Existing Plant + background	134* + 40 = 174	16	733 + 20 = 753	357 + 20 = 377	40
Proposed Modification + background	109* + 40 = 149	13	472† + 20 = 492	229** + 20 = 249	25
New Source	6.9	--	51	16	--

* Day 65/1973, Direction 290°, Distance 1,000 m
† Day 329/1973 Period 5, Direction 320°, Distance 800 m
** Day 319/1971, Direction 260°, Distance 1,000 m

Source: ESE, 1981.

Table 2-6. National and State of Florida Ambient Air Quality Standards

Pollutant	Averaging Time	National Primary Standard	National Secondary Standard	Florida
Suspended Particulate Matter	Annual Geometric Mean	75 ug/m^3	60 ug/m^3	60 ug/m^3
	24-Hour Maximum*	260 ug/m^3	150 ug/m^3	150 ug/m^3
Sulfur Dioxide	Annual Arithmetic Mean	80 ug/m^3	NA†	60 ug/m^3
	24-Hour Maximum*	365 ug/m^3	NA†	260 ug/m^3
	3-Hour Maximum*	NA†	1,300 ug/m^3	1,300 ug/m^3
Carbon Monoxide	8-Hour Maximum*	10 mg/m^3	10 mg/m^3	10 mg/m^3
	1-Hour Maximum*	40 mg/m^3	40 mg/m^3	40 mg/m^3
Hydrocarbons	3-Hour Maximum* (6 to 9 A.M.)	160 ug/m^3	160 ug/m^3	160 ug/m^3
Nitrogen Dioxide	Annual Arithmetic Mean	100 ug/m^3	100 ug/m^3	100 ug/m^3
Ozone	1-Hour Maximum*	235 ug/m^3	235 ug/m^3	160 ug/m^3
Lead	Calendar Quarter Arithmetic Mean	1.5 ug/m^3	1.5 ug/m^3	NA†

* Maximum concentration not to be exceeded more than once per year.
† No standard exists.

Sources: 40 CFR Part 50, 1980.
FAC Chapter 17-2.

Table 2-7. Highest, Second-Highest 24-Hour Ground-Level Concentrations (ug/m^3) In Directions of Interaction with Nearby Sources

Interacting Source	Direction	Day/Year	Impact of SCGC* Mill Only	Impact with Interacting Sources*
Sulfur Dioxide				
FPL-Riviera	80°	89/74	101	101
TSP				
U.S. Sugar, Bryant	190°	76/71	75	76
Osceola	210-220°	295/73	134	135
Atlantic	290°	65/73	147	149
Talisman	360°	330/72	98	99
Gulf & Western	40°	34/72	82	83
U.S. Sugar, Clewiston	100°	361/72	91	92

* Includes background of 40 ug/m^3 TSP and 20 ug/m^3 SO_2.

Source: ESE, 1981.

quality improvement, no rigorous, long-term analysis was performed with the area-wide inventory.

This discussion demonstrates that construction of the new boiler, in conjunction with the plant modifications described, will not cause or contribute to violations of any federal or State of Florida Ambient Air Quality Standard.

2.3 INCREMENT CONSUMPTION

Both federal and state PSD regulations require a demonstration that a proposed source will not cause or contribute to increases in ambient concentrations of TSP or SO_2 greater than a specified amount over a baseline concentration. Since 1974, the baseline year established by Florida DER, the only modification at the SCGC mill has been the installation of scrubbers on Boilers 1 through 5; the only construction affecting either state or federal increment consumption from this mill has resulted in a net decrease in emissions. Table 2-5 and the appended computer printouts in Appendix C show that the proposed project would result in an improvement in air quality at all points over that predicted for the present plant configuration with actual emission rates. This means that regardless of increment consuming activity by any surrounding source, the net impact of this project on any increment standard would be negative. Thus, no formal baseline was established and no explicit increment consumption analysis was performed.

3.0 ADDITIONAL IMPACTS ANALYSIS

3.1 IMPACTS ON SOILS AND VEGETATION

Impacts on soils and vegetation due to operation of the proposed sources are expected to be minor. The projected highest, second-highest 3-hour SO_2 concentration of 492 ug/m^3 and crop-season average concentration of 25 ug/m^3 (see Table 2-5) are below levels generally reported as damaging to most plant species. As an example of such damage levels, European studies have found one-half-hour levels of 3,406 ug/m^3 and long-term means of 393 ug/m^3 to approximate threshold levels for several species (Heck and Brandt, 1977). Alfalfa, which is commonly thought to be one of the most SO_2-sensitive species, has a 2-hour threshold level of at least 2,620 ug/m^3 and an 8-hour threshold of 655 ug/m^3 (Heck and Brandt, 1977). No data are available on the sensitivity of sugar cane to SO_2 concentrations. No evidence of damage to the cane surrounding the SCGC mill has been observed to date. The proposed modification will result in reduced concentration impacts on surrounding vegetation. No discernible impacts are predicted from this source.

Particulate matter is generally considered to have a relatively unimportant effect on vegetation (Jacobson and Hill, 1970). The particulate matter generated by this source is largely ash from the burning of the same vegetation which would be impacted. Emitted particulate will be mostly suspended and will deposit on vegetation primarily through plume impaction.

Plant species classified as "sensitive" to NO_2, such as pinto bean, cucumber, lettuce, and tomato, displayed injury when exposed to NO_2 levels of 3,760 to 4,960 ug/m^3 for a 2-hour period. Extremely resistant species, such as heath, were unaffected by an exposure of 1,900,000 ug/m^3 for 1 hour. Blue grass, orange tree plants, and rye are all classified as "intermediate" in resistance to NO_2 injury. It has been found that NO_x concentration is more important to plant injury than the duration of exposure (Jacobson, et al., 1970). Because of the low levels of NO_2 predicted to result from the proposed modification (less than 10 ug/m^3, estimated annual average), no effect on plants or soils is expected.

Effects of SO_2, NO_2, and particulate matter emissions on soils are expected to be negligible. Acid rain effects in the area are generally unknown, due to a lack of data for the region (Florida Sulfur Oxides Study, Inc., 1978). The potential for long-range pollutant transport or significant acid rain effects from the proposed source is considered to be very low.

3.2 VISIBILITY IMPACTS

A Level I visibility screening analysis (EPA, 1980) was conducted which confirmed that no visibility impairment should occur in the Class I area. The absolute values of the three Level I contrast parameters (C1—plume contrast against the sky; C2--plume contrast against terrain; and C3--change in the sky/terrain contrast caused by primary and secondary aerosol) are well below 0.10. Thus, it is highly unlikely that the emissions source would cause adverse visibility impairment in Class I areas.

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Appendix A

Emissions Calculations

Table A-1. Derivation of Process Input Weight and Maximum Sulfur Dioxide Emissions (Uncontrolled)

Bagasse 8,380 lb steam/ton dry bagasse

$$1{,}050\ \frac{\text{Btu}}{\text{lb steam}} \times \frac{1}{0.55} \times \frac{\text{1 lb dry bagasse}}{\text{8,000 Btu}} \times \frac{\text{0.001 lb S}}{\text{lb bagasse}} \times \frac{\text{2 lb } SO_2}{\text{1 lb S}}$$

$$= 4.8 \times 10^{-4}\ \frac{\text{lb } SO_2}{\text{lb steam from bagasse}}$$

Residue 10,600 lb steam/ton dry residue

$$1{,}050\ \frac{\text{Btu}}{\text{lb steam}} \times \frac{1}{0.625} \times \frac{\text{1 lb dry residue}}{\text{8,900 Btu}} \times \frac{\text{0.004 lb S}}{\text{lb residue}} \times \frac{\text{2 lb } SO_2}{\text{1 lb S}}$$

$$= 1.5 \times 10^{-3}\ \frac{\text{lb } SO_2}{\text{lb steam from residue}}$$

2.4% Sulfur Oil 108 lb steam/gallon oil

$$1{,}050\ \frac{\text{Btu}}{\text{lb steam}} \times \frac{1}{0.8} \times \frac{\text{1 lb}}{\text{17,500 Btu}} \times \frac{\text{0.024 lbS}}{\text{lb oil}} \times \frac{\text{2 lb } SO_2}{\text{1 lb S}}$$

$$= 3.6 \times 10^{-3}\ \frac{\text{lb } SO_2}{\text{lb steam from 2.4-\% S oil}}$$

1% Sulfur Oil 108 lb steam/gallon oil

$$1.5 \times 10^{-3}\ \frac{\text{lb } SO_2}{\text{lb steam from 1-\% S oil}}$$

Source: ESE, 1981.

Table A-2. Emissions per 1,000 lb Steam

For Every 1,000 lb Steam Generated From:	Particulate @ 0.2 lb/10^6 Btu (lb)	Particulate @ 0.25 lb/10^6 Btu (lb)	SO^2 (lb)	Ft^3 Exit Gas Saturated at 160°F
Bagasse	0.38	0.48	0.29*	40,800
Residue	0.34	0.42	0.9*	36,400
Oil (2.4%)	0.13†	0.13†	3.6	25,920**
Oil (1.8%)	0.13†	0.13†	2.7	25,920**
Oil (1.0%)	0.13†	0.13†	1.5	25,920**

* Including 40-percent SO_2 loss.
† Oil at 0.1 lb/10^6 Btu.
** For scrubber exit conditions (for Boilers 6 and 7, unscrubbed, this would be 34,328).

Source: ESE, 1981.

Table A-3. Maximum Pollutant Emissions from Individual Boilers

Boiler	Rated Capacity (1000 lb steam)	Worst-Case Particulate (no oil burned in combination boilers) lb Particulate/hr* g/s 0.25 lb/10^6 Btu	0.02 lb/10^6 Btu	10^3 ACFM (m^3/s)	Worst-Case Sulfur Dioxide — Fuel Rate (per hour), Dry Basis: Residue (ton) (lb steam)	Bagasse (ton) (lb steam)	Oil (gal) (lb steam)	lb SO_2/hr† (g/s)	10^3 ACFM (m^3/s)
1	120	54 (6.8)	— —	77.2 (36.4)	8.3 (88,000)	3.5 (28,900)	29 (3,100)	96 (12.1)	74.4 (35.1)
2	120	54 (6.8)	— —	77.2 (36.4)	8.3 (88,000)	3.5 (28,900)	29 (3,100)	96 (12.1)	74.4 (35.1)
3	100	45 (5.7)	— —	64.3 (30.4)	—	11.6 (97,400)	24 (2,600)	35 (4.4)	67.4 (31.3)
4	240	—	86.4 (10.9)	154.3 (72.8)	16.6 (176,000)	6.9 (57,700)	58 (6,300)	192 (24.2)	149 (70.2)
5	160	72 (9.1)	— —	103.0 (48.6)	11.1 (117,700)	4.6 (38,100)	39 (4,200)	128 (16.2)	99 (46.8)
6 & 7	2(75)	—	2 x (9.8)** 2 x (1.2)	2x(42.9) 2x(20.3)	—	—	2x(694) 2x(75,000)	2x(203) 2x(25.5)	2x(42.9) 2x(20.3)
8 (New)	264††	—	95.0 (12.0)	169.8 (80.2)	18.3 (194,000)	7.5 (63,100)	64 (6,900)	211 (26.7)	164 (77.2)
Total Fuel Rate					1,500 tons/day	900 tons/day	39,100 gpd		

* Average of bagasse and residue values (except #3).
† Including 40-percent SO_2 loss for residue and bagasse only.
** Oil at 0.1 lb/10^6 Btu.
†† Rated capacity plus 10-percent peak factor.

Note: Oil mix in 1980:

1,465,577 gal	2.4%
1,126,463 gal	1.0%
2,592,040 gal	1.8%

Note: Using average oil consumption in latest permit renewals for Boilers 1 through 5.
Boilers 6 and 7 at maximum rated capacity.
All boilers with 1.8% sulfur. Assume 61.5 tons/hour (1,500 tons/day) dry residue apportioned over Boilers 1, 2, 4, 5, and New. Remainder is bagasse.

Source: ESE, 1981.

Appendix B

Combustion and Flow Calculations

Table B-1. Exit Gas Calculation

	Mole Dry Gas Per 100 lb Wet Fuel	+	0.48 mol (160°F) Per Mol Dry Air	=	Lb Mol Gas Leaving Scrubber @ 160°F per 100 lb Wet Fuel
Bagasse	11.6		5.57		17.2
Residue	17.4		8.35		25.8
Oil	52.2		25.06		77.3
Nos. 6 & 7	58.2		0		58.2

$R = 1545.3\ ft^2\ lb_f/°R\text{-}lb\ mole$

$@\ 160°F = 620°R \qquad 14.7\ psi = 2116.8\ lb_f/ft^2$

$$V = \frac{n\ RT}{P}$$

$$ft^3 = N\ lb\ mole \quad \frac{1545.3\ \dfrac{ft^2\ lb_f}{°R\text{-}lb\ mole} \times 620°R}{2116.8\ lb_f/ft^2}$$

$$V = 452.6\ n\ ft^3$$

Bagasse 7,785 ft^3/100 lb wet fuel

Residue 11,677 ft^3/100 lb wet fuel

Oil 34,986 ft^3/100 lb fuel (when passing through scrubber)

Oil (Nos. 6 & 7, no scrubber) $26{,}341 \times \frac{1091}{620} = 46{,}343\ ft^3/100\ lb\ fuel$

Source: ESE, 1981.

Table B-2. Oil No. 6, 2.4 Percent, Combustion Calculation

Ultimate Analysis lb/100 lb Fuel				Moles per 100 lb Fuel		Required for Combustion Moles/100 lb Fuel at 100 Percent O_2	Dry Air
C	85.6	.12	=	7.13 x 1.0/4.76	=	7.13	33.94
H_2	9.7	.2.02	=	4.80 x 0.5/2.38	=	2.40	11.42
O_2	2.0	.30	=	0.07 —			
N_2				—			
S	2.4	.32	=	0.08 x 1.0/4.76	=	0.08	0.38
H_2O	0.2	.18		0.01 —			
Ash	0.1						
				12.09		9.61	45.74
				Less O_2 in fuel		-0.04	-0.17
				0.035 x 4.76 = 0.17		9.57	45.57

$$\frac{248{,}500 \text{ lb air}^\dagger}{15{,}688 \text{ lb oil}} = \begin{array}{l}1{,}584 \text{ lb air/100 lb fuel} \\ 54.6 \text{ mole/100 lb fuel}\end{array}$$

	O_2	Air
54.6 ―>	11.5	54.6
xs Air	—	9.03 (19.8% xs)*
xs O_2	1.9	--

Moles H_2O in air (54.6 x 29 x 0.013) . 18 = 1.14

Products of Combustion

CO_2	7.13	x 1	7.13	
H_2O	4.80	x 1 + 0.01 + 1.14	5.95	
SO_2	0.08	x 1	0.08	
N_2	54.6	x 0.79	43.13	
O_2	xs		1.9	
			58.19	―> 52.24 dry moles per 100 lb fuel

Saturated air at 160°: 0.3 lb H_2O/lb air
0.48 lb mole H_2O/lb mole air

* Approximately.
† Plant records

Sources: ESE, 1981.
SCGC, 1981.

Table B-3. Bagasse, Combustion Calculation

Ultimate Analysis lb/100 lb Fuel				Moles per 100 lb Wet Fuel			Required for Combustion Moles/100 lb Fuel at 100 Percent O_2	Dry Air
C	21.8	.12	=	1.82	x 1.0/4.76	=	1.82	8.66
H_2	2.8	.2.02	=	1.39	x 0.5/2.38	=	0.70	3.31
O_2	20.4	.32	=	0.64	—		0	
N_2	0.1	.28	=	0.0	—		0	
S	0.1	.32	=	0.0	x 1.0/4.76	=	0	
H_2O	54.5	.18	=	3.03	—			
Ash	0.3							
	100.0			6.88			2.52	11.97
				Less O_2 in fuel			-0.64	-3.05
				0.64 x 4.76 = 3.05 mol air/0.19 mol O_2			1.88	8.95

$\frac{368{,}500 \text{ lb air}^\dagger}{108{,}545 \text{ lb bagasse}}$ = 3.39 lb air/lb bagasse (29 lb mol/lb air)
11.69 lb mol air/100 lb wet fuel

	Required for Combustion Moles/100 lb Fuel O_2	Air
339 lb air	2.45	11.69 (31% xs)*
xs Air = 11.69 - 8.95	--	2.74
xs O_2 = 2.45 - 1.88	0.57	--

Moles H_2O in air (11.69 x 29 x 0 x 0.013) . 18 = 0.24

Products of Combustion			Moles/100 lb Wet Fuel
CO_2	1.82	x 1	1.82
H_2O	1.39	x 1 + 3.03 + 0.24	4.66
SO_2	0.0		0.0
N_2	11.69	x 0.79	9.24
O_2	xs		0.57
			16.29 ---> 11.63 mol dry gas per 100 lb wet fuel

Moles H_2O in saturated air at 160°F = 0.48 mol/mol air
(0.3 lb/lb air)

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* Approximately.
† Plant records.

Sources: ESE, 1981.
SCGC, 1981.

Table B-4. Residue, Combustion Calculation

Ultimate Analysis lb/100 lb Fuel				Moles per 100 lb Wet Fuel		Required for Combustion Moles/100 lb Fuel at 100 Percent O_2	Dry Air
C	32.1	.12	=	2.68 x 1.0/4.76	=	2.68	12.76
H_2	3.4	.2.02	=	1.68 x 0.5/2.38	=	0.84	4.00
O_2	22.9	.32	=	0.72 —			
N_2	0.2	.28	=	0.01 —			
S	0.3	.32	=	0.01 x 1.0/4.76	=	0.01	0.05
H_2O	39.5	.18	=	2.19 —			
Ash	1.6						
	100.0			7.29		3.53	16.81
				Less O_2 in fuel (0.72) x 4.76 = 3.43		-0.72	-3.43

$$\frac{332{,}000 \text{ lb air}^{\dagger}}{65{,}242 \text{ lb residue}} = \begin{array}{l}509 \text{ lb air/100 lb wet fuel} \\ 17.55 \text{ mol air/100 lb wet fuel}\end{array}$$

	O_2	Air
17.55 mol --->	3.68	17.55 (31% xs)*
xs Air	--	4.17
xs O_2	0.87	--

Moles H_2O in air (17.55 x 29 x 0 x 0.013) . 18 = 0.37

Products of Combustion			Moles/100 lb Wet Fuel	
CO_2	2.68	x 1	2.68	
H_2O	1.68	x 1 + 2.19 + 0.37	4.24	
SO_2	0.01	x 1	0.01	
N_2	17.55	x 0.79	13.86	
O_2	xs		0.87	
			21.66	---> 17.42 dry moles per 100 lb wet fuel

Saturated air at 160°F: 0.3 lb H_2O/lb air
0.48 lb mole H_2O/lb mole air

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* Approximately.
† Plant records.

Sources: ESE, 1981.
SCGC, 1981.