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BUREAU OF AIR REGULATION

BOILER MACT COMPLIANCE APPLICATION
BOILER NO. 8
U.S. SUGAR CORPORATION
CLEWISTON, FLORIDA

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

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

February 2005
0437615

DISTRIBUTION:
4 Copies – FDEP
2 Copies – U.S. Sugar Corporation
1 Copy – Golder Associates Inc.

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **United States Sugar Corporation**	
2. Site Name: **U.S. Sugar Clewiston Mill**	
3. Facility Identification Number: **0510003**	
4. Facility Location...: Street Address or Other Locator: **W.C. Owens Ave. and S.R. 832** City: **Clewiston** County: **Hendry** Zip Code: **33440**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **William A. Raiola, Senior Vice President, Sugar Processing Operations**
2. Application Contact Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce Deleon Ave.** City: **Clewiston** State: **FL** Zip Code: **33440**
3. Application Contact Telephone Numbers... Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**
4. Application Contact Email Address: **wraiola@ussugar**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	2-23-05
2. Project Number(s):	0510003-030-AC
3. PSD Number (if applicable):	PSD-FL-333B
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

- [x] Air construction permit.

Air Operation Permit

- [ ] Initial Title V air operation permit.
- [ ] Title V air operation permit revision.
- [ ] Title V air operation permit renewal.
- [ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- [ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- [ ] Air construction permit and Title V permit revision, incorporating the proposed project.
- [ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- [ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Implement provisions of the Boiler MACT regulations (40 CFR Part 63, Subpart DDDDD), promulgated on September 13, 2004, as applicable to the new Boiler No. 8.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
028	Boiler No. 8		

Application Processing Fee

Check one: ☐ Attached - Amount: $____________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name: **William A. Raiola, Senior Vice President, Sugar Processing Operations**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce Deleon Ave.** City: **Clewistion** State: **FL** Zip Code: **33440**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**
4.	Owner/Authorized Representative Email Address: **wraiola@ussugar.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* W. Raiola (signature) Feb. 21, 2004 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:

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

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

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

   ______________________________ ____________________
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

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

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

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

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

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

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

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

David A. Buff — 2/22/05

Signature — Date

(seal)

* Attach any exception to certification statement.

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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **506.1** North (km) **2956.9**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26/44/06** Longitude (DD/MM/SS) **80/56/19**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **20**	6. Facility SIC(s): **2061** **2062**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **William A. Raiola, Vice President, Sugar Processing Operations**
2. Facility Contact Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce de Leon Ave.** City: **Clewiston** State: **Florida** Zip Code: **33440**
3. Facility Contact Telephone Numbers: Telephone: **(863) 983-8121** ext. Fax: **(863) 902-2729**
4. Facility Contact Email Address: **wraiola@ussugar.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **One or more emission units potentially subject to NESHAP for asbestos removal in the event that the facility may wish to perform asbestos removal in the future. Boiler No. 8 is also subject to 40 CFR 63, Subpart DDDDD.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total - PM	**A**	**No**
Sulfur Dioxide - SO_2	**A**	**No**
Nitrogen Oxides - NO_x	**A**	**No**
Carbon Monoxide - CO	**A**	**No**
Particulate Matter - PM_{10}	**A**	**No**
Sulfuric Acid Mist - SAM	**A**	**No**
Total Hazardous Air Pollutants - HAPs	**A**	**No**
Volatile Organic Compounds - VOC	**A**	**No**
Acetaldehyde - H001	**A**	**No**
Benzene - H017	**A**	**No**
Formaldehyde - H095	**A**	**No**
Hydrogen Chloride - H106	**A**	**No**
Mercury - H114	**B**	**No**
Phenol - H144	**A**	**No**
Polycyclic Organic Matter - H151	**A**	**No**
Styrene - H163	**A**	**No**
Toluene - H169	**A**	**No**
Naphthalene - H132	**A**	**No**
Dibenzofuran - H058	**A**	**No**
Ammonia - NH_3	**B**	**No**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID Nos. Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **UC-FI-C1** ☐ Previously Submitted, Date:
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: **UC-FI-C2** ☐ Previously Submitted, Date:
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date: ____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: **UC-FI-CC1** ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: ☒ Attached, Document ID: **Attachment A**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **Attachment C**
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☐ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID: ____ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID: ____ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID: ____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID: ____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☐ Not Applicable (no exempt units at facility)	

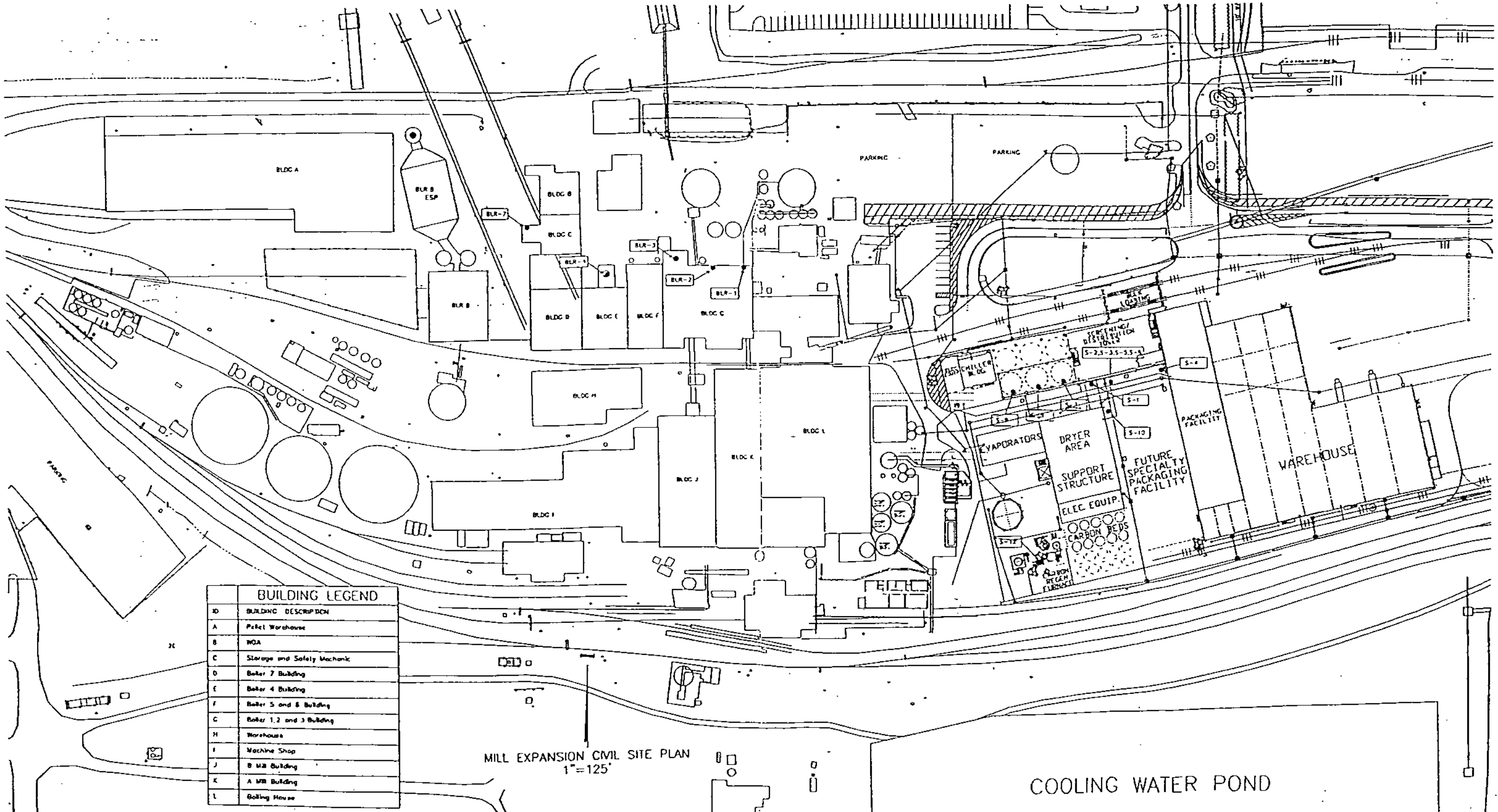
Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☐ Not Applicable

Additional Requirements Comment

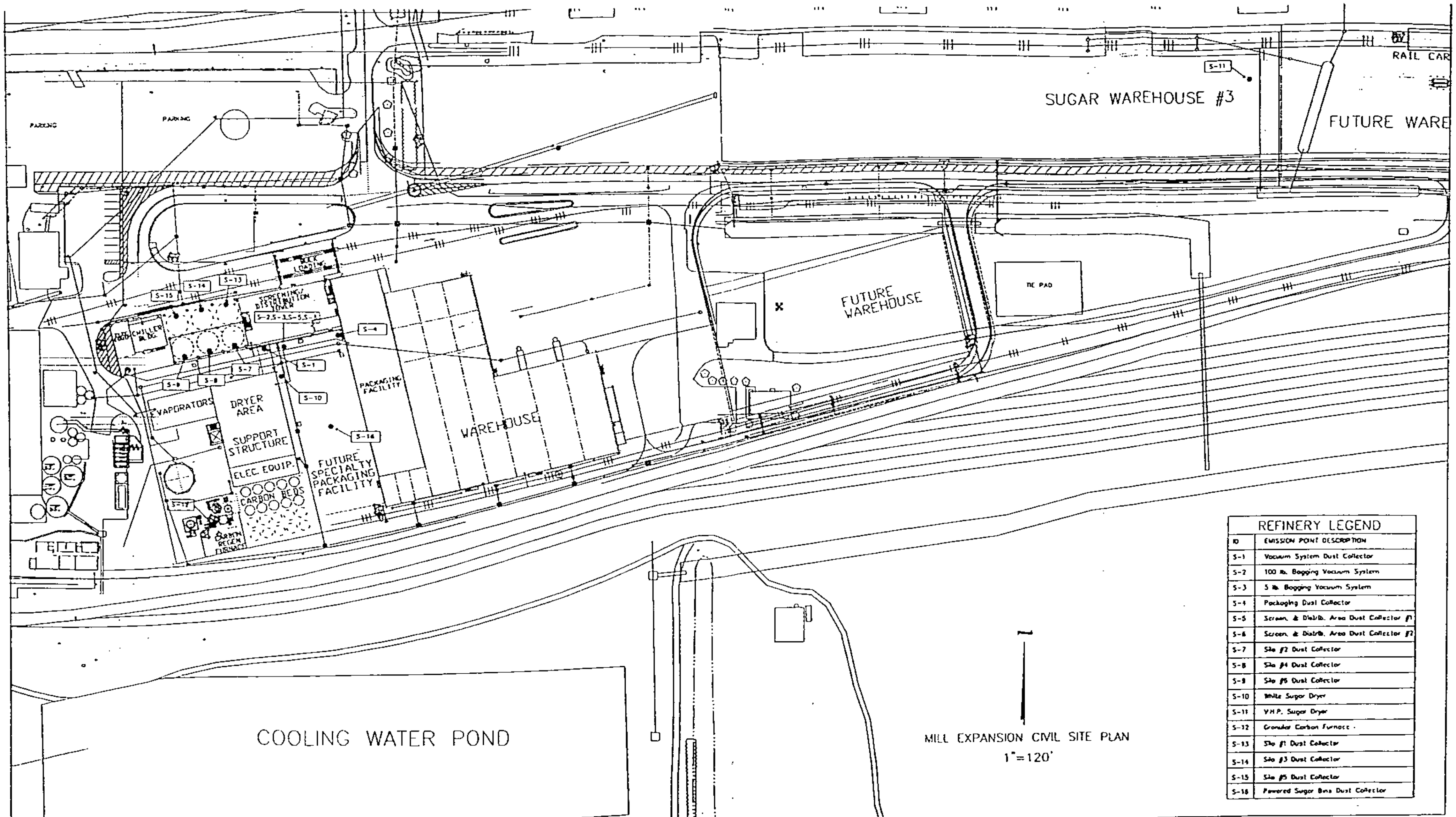
ATTACHMENT UC-FI-C1

FACILITY PLOT PLANS



Attachment UC-FI-C1, Page 1. Clewiston Mill Plot Plan of Existing Sources and Major Buildings

Golder Associates



REFINERY LEGEND

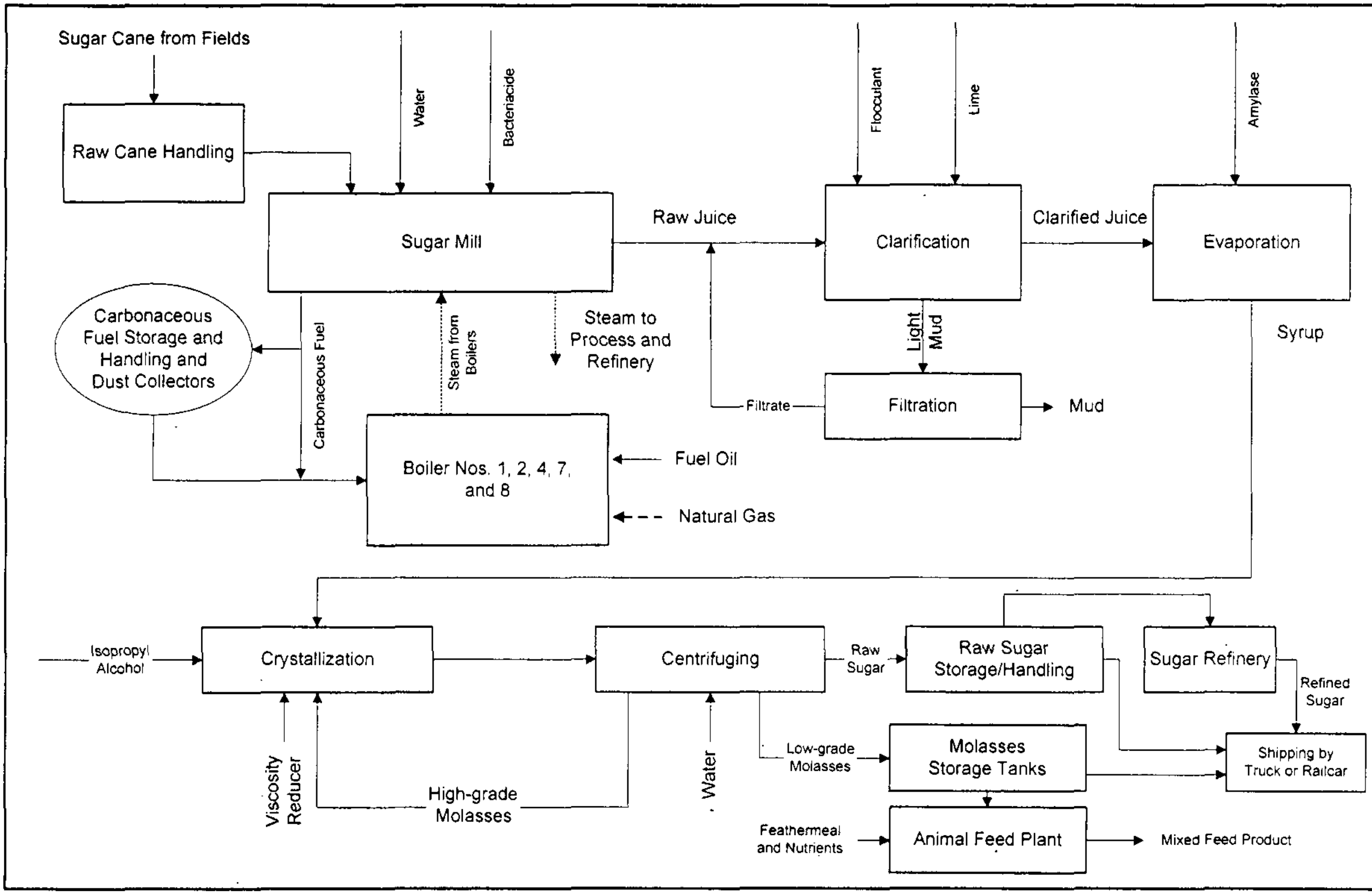
ID	EMISSION POINT DESCRIPTION
S-1	Vacuum System Dust Collector
S-2	100 lb. Bagging Vacuum System
S-3	5 lb. Bagging Vacuum System
S-4	Packaging Dust Collector
S-5	Screen. & Distrib. Area Dust Collector #1
S-6	Screen. & Distrib. Area Dust Collector #2
S-7	Silo #2 Dust Collector
S-8	Silo #4 Dust Collector
S-9	Silo #6 Dust Collector
S-10	White Sugar Dryer
S-11	V.H.P. Sugar Dryer
S-12	Granular Carbon Furnace
S-13	Silo #1 Dust Collector
S-14	Silo #3 Dust Collector
S-15	Silo #5 Dust Collector
S-16	Powered Sugar Bins Dust Collector

Attachment UC-FI-C1, Page 2. Location of Sugar Refinery Sources and Major Buildings

Golder Associates

ATTACHMENT UC-FI-C2

PROCESS FLOW DIAGRAM



Attachment UC-FI-C3
Process Flow Diagram
U.S. Sugar Corporation
Clewiston Mill, Florida

Process Flow Legend
Solid/Liquid →
Steam ⋯→
Gaseous - - →

Clewiston Sugar Mill Facility

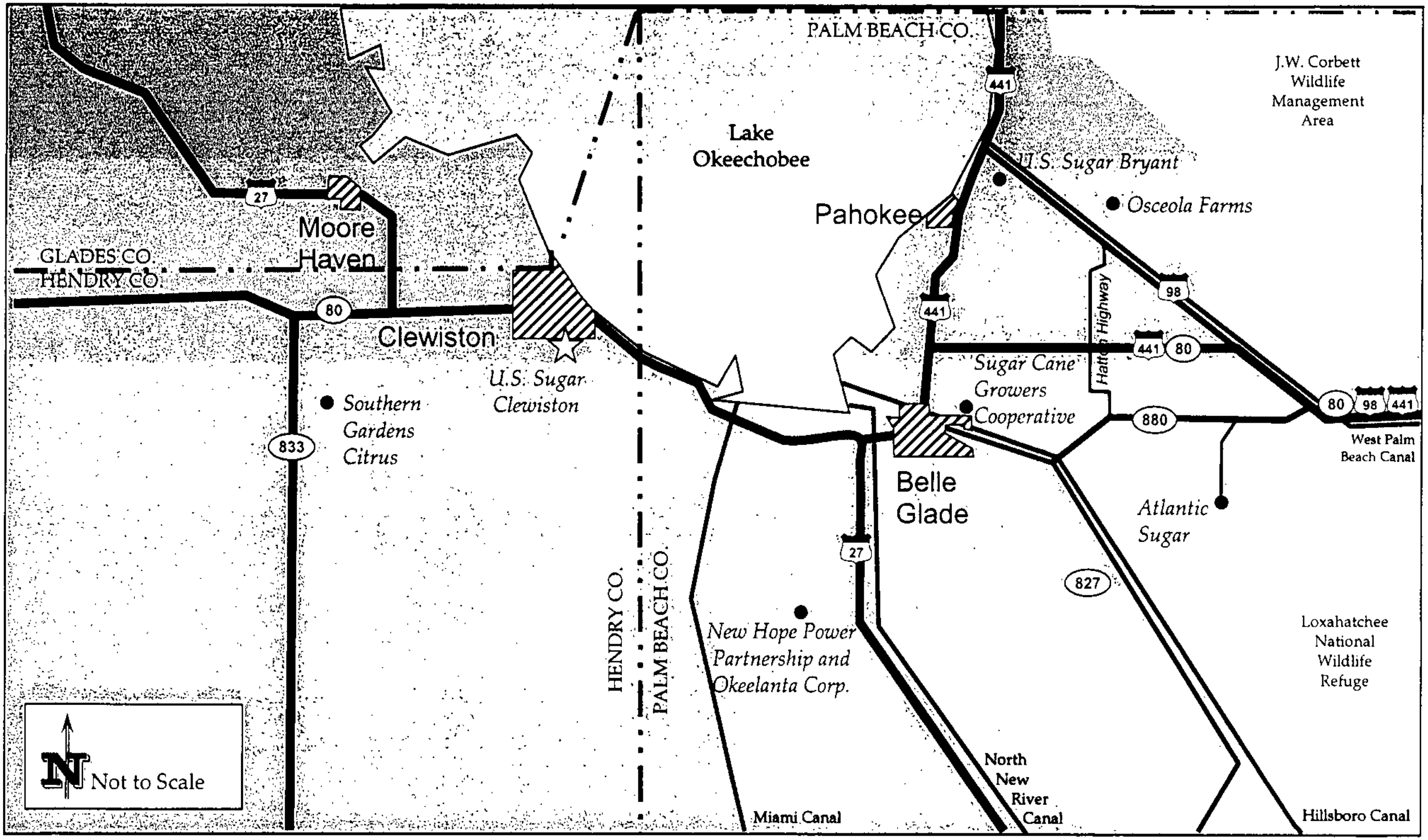
Filename: 0437615/4/4.4/UC-FI-C2.vsd

Date: 01/11/05

Golder Associates

ATTACHMENT UC-FI-CC1

AREA MAP SHOWING FACILITY LOCATION



Attachment UC-FI-CC1
Location of U.S. Sugar Corporation, Clewiston Mill

Source: Golder Associates Inc., 2004.

Golder Associates

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application – For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application – For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
   - ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   - ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)
   - ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
   - ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
   - ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Boiler No. 8

3. Emissions Unit Identification Number: **028**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**NOV 2003**		**20**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

    Stoker boiler fired by carbonaceous fuel and low sulfur No. 2 fuel oil.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator** **Wet Sand Separator** **Selective Non-Catalytic Reduction System (SNCR)**	
2. Control Device or Method Code(s): **010, 099, 107**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **550,000 lb/hr steam**	
3. Maximum Heat Input Rate: **1,030** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on 1-hour maximum steam rate (above) for carbonaceous fuel firing. Maximum 24-hour average firing for carbonaceous fuel is 936 MMBtu/hr. Maximum for No. 2 fuel oil is 562 MMBtu/hr.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-8**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **13.0** feet
8. Exit Temperature: **335** °F	9. Actual Volumetric Flow Rate: **425,400** acfm	10. Water Vapor: **24** %
11. Maximum Dry Standard Flow Rate: **225,000** dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on biomass firing at maximum 24-hour heat input rate. Maximum Dry Standard Flow Rate is at 7-percent oxygen.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; industrial; bagasse; all boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **143.06**	5. Maximum Annual Rate: **939,875**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.1 (dry)**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on 1,030 MMBtu/hr (1-hr max) and maximum annual rate based on 75-percent capacity factor or 6,767,100 MMBtu/yr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External combustion boilers; industrial; distillate oil: grades 1 and 2**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **1000 Gallons**	
4. Maximum Hourly Rate: **4.161**	5. Maximum Annual Rate: **6,073.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Rates based on proposed 562 MMBtu/hr and a maximum of 6,073,600 gallons of fuel oil per year.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	099	010	EL
PM_{10}	099	010	EL
SO_2			EL
NO_x	107		EL
CO			EL
VOC			EL
SAM			NS
PB	099	010	NS
H017 (Benzene)			NS
H095 (Formaldehyde)			NS
H106 (Hydrogen Chloride)	010		EL
H114 (Mercury)			EL
HAPs			NS
Ammonia			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **25.75** lb/hour **84.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **MACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.025 lb/MMBtu = 25.75 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.025 lb/MMBtu ÷ 2,000 lb/ton = 84.6 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-024-AC/PSD-FL-333A and 40 CFR 63, Subpart DDDDD, Table 1.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **25.75** lb/hour **84.6** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT limit, 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.8** lb/hour **88.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.026 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.026 lb/MMBtu = 26.8 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.026 lb/MMBtu ÷ 2,000 lb/ton = 88.0 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-024-AC/PSD-FL-333A.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.026 lb/MMBtu**	4. Equivalent Allowable Emissions: **26.8** lb/hour **88.0** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **175.1** lb/hour **203.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.17 lb/MMBtu (1-hour)** Reference: **Similar Boilers**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.17 lb/MMBtu = 175.1 lb/hr** **3-hour and Annual: 6,767,100 MMBtu/yr x 0.06 lb/MMBtu ÷ 2,000 lb/ton = 203.0 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. 3-hr and Annual based on Permit No. 0510003-024-AC/PSD-FL-333A.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **56.2** lb/hour **203.0** tons/year
5. Method of Compliance: **EPA Method 6c**	
6. Allowable Emissions Comment (Description of Operating Method): **24-hour and annual limit is 0.06 lb/MMBtu. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lbMMBtu**	4. Equivalent Allowable Emissions: **28.1** lb/hour **20.5** tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions representative of No. 2 fuel oil firing with 0.05% S. Annual emissions based on proposed limit of 6,073,600 gal/yr.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **309.0** lb/hour **744.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.14 lb/MMBtu, 30-day rolling average** Reference: **Permit No. 0510003-24-AC/PSD-FL-333A**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.030 lb/MMBtu = 309.0 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 473.7 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max hourly rate represents worst-case uncontrolled without SNCR system. Annual average is 30-day rolling average limit, based on permit No. 0510003-024-AC/PSD-FL-333A.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.14 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **473.7** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit based on 30-day rolling average.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6,695** lb/hour **1,285** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.38 lb/MMBtu, 12-month average** Reference: **PSD Permit 0510003-024-AC/PSD-FL-333A**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Maximum hourly rate: 1,030 MMBtu/hr x 6.5 lb/MMBtu = 6,383 lb/hr
30-day rolling average based on 40 CFR 63, Subpart DDDDD:
400 ppmvd @ 7-percent O_2 x 225,000 dscfm @ 7-percent O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1,545.6/28) ft-lb_f/lb_m-°R ÷ 528°R = 392.2 lb/hr
Annual based on 30-day rolling average: 392.2 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,717.8 TPY
Annual limit based on PSD-FL-333A: 0.38 lb/MMBtu (12-month rolling average)
6,767,100 MMBtu/yr x 0.38 lb/MMBtu ÷ 2,000 lb/ton = 1,285 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Annual limit based on 12-month rolling average, based on Permit No. 0510003-024-AC/PSD-FL-333A.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.38 lb/MMBtu**	4. Equivalent Allowable Emissions: **6,695** lb/hour **1,285** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit from PSD-FL-333A based on 12-month rolling average. The lb/MMBtu limit excludes periods of startup, shutdown, and malfunction (SSM). Annual tons per year limit includes periods of SSM.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **400 ppmvd @ 7-percent O_2**	4. Equivalent Allowable Emissions: **392.2** lb/hour **1,717.8** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 63, Subpart DDDDD, Table 1. Limit based on 30-day rolling average.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **51.5** lb/hour **168.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.05 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Maximum hourly rate: 1,030 MMBtu/hr x 0.05 lb/MMBtu = 51.5 lb/hr** **Annual: 6,767,100 MMBtu/yr x 0.026 lb/MMBtu ÷ 2,000 lb/ton = 169.2 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-024-AC/PSD-FL-333A.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **51.5** lb/hour **169.2** tons/year
5. Method of Compliance: **EPA Methods 18 and 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10.72** lb/hour **12.43** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0104 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **1-hour average: 1,030 MMBtu/hr x 0.0104 lb/MMBtu = 10.72 lb/hr** **3-hour and Annual: 6,767,100 MMBtu/yr x 0.0037 lb/MMBtu ÷ 2,000 lb/ton = 12.43 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions representative of bagasse firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.016** lb/hour **0.052** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.55 x 10^{-5} lb/MMBtu** Reference: **Bagasse analysis and 50-percent removal**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Bagasse Analysis: 3.09 x 10^{-5} lb/MMBtu

3.09 x 10^{-5} lb/MMBtu x 0.50 x 1,030 MMBtu/hr = 0.016 lb/hr
3.09 x 10^{-5} lb/MMBtu x 0.50 x 6,767,100 MMBtu/yr x ton/2,000 lb = 0.052 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Emission factor based on bagasse firing only. Based on bagasse analysis and assuming 50-percent removal in wet scrubber/ESP, based on stack testing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **H114 (Mercury)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00309** lb/hour **0.0102** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3 x 10^{-6} lb/MMBtu** Reference: **40 CFR 63, Subpart DDDDD, Table 1.**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **3 x 10^{-6} lb/MMBtu x 1,030 MMBtu/hr = 0.00309 lb/hr** **3 x 10^{-6} lb/MMBtu x 6,767,100 MMBtu/yr ÷ 2,000 lb/ton = 0.0102 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Emission factor based on bagasse firing only.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3×10^{-6} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.00309** lb/hour **0.0102** tons/year
5. Method of Compliance: **Bagasse analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Fluorides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.62** lb/hour **2.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6×10^{-4} lb/MMBtu** Reference: **Similar Stack Test Data**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **6×10^{-4} lb/MMBtu x 1,030 MMBtu/hr = 0.62 lb/hr** **6×10^{-4} lb/MMBtu x 6,767,100 MMBtu/yr ÷ 2,000 lb/ton = 2.03 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Based on biomass firing**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **HCl**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **20.6** lb/hour **67.67** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.02 lb/MMBtu** Reference: **40 CFR 63, Subpart DDDDD, Table 1.**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **0.02 lb/MMBtu x 1,030 MMBtu/hr = 20.6 lb/hr** **0.02 lb/MMBtu x 6,767,100 MMBtu/yr ÷ 2,000 lb/ton = 67.67**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.02 lb/MMBtu**	4. Equivalent Allowable Emissions: **20.6** lb/hour **67.67** tons/year
5. Method of Compliance: **Annual stack testing using EPA Method 26A**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NH_3**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.9** lb/hour **52.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **20 ppmvd @ 7-percent O_2** Reference: **PSD-FL-333A**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **20 ppmvd @ 7-percent O_2 x 225,000 dscfm @ 7-percent O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1545.6/17) ft-lb_f/lb_m-°R ÷ 528°R = 11.9 lb/hr** **11.9 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 52.1 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Emission factor based on Permit No. PSD-FL-333A.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd @ 7-percent O_2**	4. Equivalent Allowable Emissions: **11.9** lb/hour **52.1** tons/year
5. Method of Compliance: **Annual stack test by method EPA CTM-027.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on Permit No. PSD-FL-333A.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(5), F.A.C., BACT and NSPS Subpart Db.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Based on 40 CFR 63, Subpart DDDDD and Permit No. 0510003-024-AC/PSD-FL-333A.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Based on BACT and Permit No. 0510003-024-AC/PSD-FL-333A.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I1 ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I2 ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I3 ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: UC-EU1-I4 ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date _____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable	

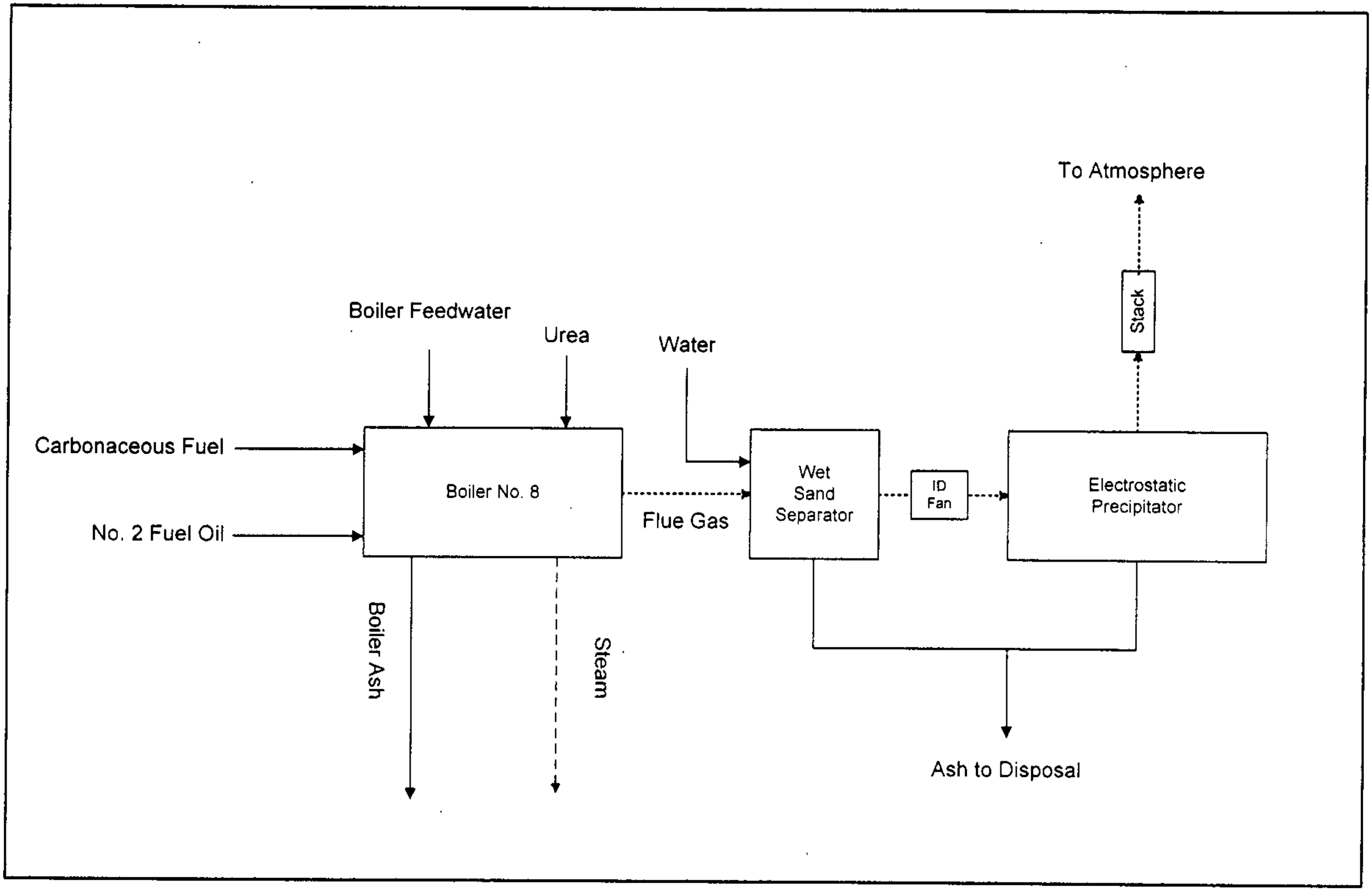
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT UC-EU1-I1

PROCESS FLOW DIAGRAM



Attachment UC-EU1-I1
Boiler No. 8 Process Flow Diagram
U.S. Sugar Corporation
Clewiston Mill, Florida

Process Flow Legend
Solid/Liquid
Gaseous
Steam

File: 0437615/4/4.4/UC-EU1-I1.vsd
Date: 1/11/05

Golder Associates

ATTACHMENT UC-EU1-I2

FUEL ANALYSIS

ATTACHMENT UC-EU1-I2

BOILER NO. 8 FUEL ANALYSIS

Parameter	Fuel	
	Carbonaceous Fuel [a]	No. 2 Fuel Oil (0.05% S max)
Density (lb/gal)	--	6.83
Approximate Heating Value (Btu/lb)	3,600 [b]	19,910
Approximate Heating Value (Btu/gal)	--	135,000
Ultimate Analysis (dry basis):		
Carbon	47.6%	84.7%
Hydrogen	6.0%	15.3%
Nitrogen	0.38%	0.015%
Oxygen	42.1%	0.38%
Sulfur	0.03% - 0.07%	0.05%
Ash/Inorganic	2.6% - 5.3%	0.06% [c]
Moisture	49% - 55%	0.51% [c]

Represents typical values.

[a] Source: U.S. Sugar fuel analysis averages.
[b] Wet basis for bagasse.
[c] Source: Perry's Chemical Engineer's Handbook. Sixth Edition, 1984. Represents average fuel characteristics.

ATTACHMENT UC-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT UC-EU1-I3a

CONTROL EQUIPMENT PARAMENTERS FOR BOILER NO. 8
AT U.S. SUGAR CLEWISTON MILL

WET SAND SEPARATORS*

Control Device Type	Wet Cyclone
Manufacturer and Model No.	Thermal Energy Systems
Inlet Flue Gas Temp (°F)	400
Inlet Design Flue Gas Flow Rate (acfm)	230,000
Inlet Expected Flue Gas Flow Rate (acfm)	212,700
Inlet Moisture (% Volume)	24
Cyclone Diameter (ft)	22
Cyclone Height (ft)	35
No. of Spray Nozzles (Cyclone)	5
No. of Spray Nozzles (Inlet Duct)	9
Total Water Flow to Nozzles (gpm)	713
Pressure Drop (in H_2O)	4
Overall PM Collection Efficiency (%)	80

*There are two identical units operating in parallel; Data is for each unit.

ATTACHMENT UC-EU1-I3b

CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 8
U.S. SUGAR CLEWISTON MILL

ELECTROSTATIC PRECIPITATOR

Manufacturer and Model No.	PPC Industries Model No. 41R-1536-5712P		
Inlet Flue Gas Temp (°F)			335
Inlet Design Flue Gas Flow Rate (acfm)			432,500
Moisture (% Volume)			20
No. of Precipitators			1
Precipitation Type			Rigid Electrode
Total Number of Fields			5
Total Installed Collection Area (ft^2)			154,360
Gas Velocity (ft/s)			3.25
Specific Collection Area (ft^2/1,000 acfm)			356
Power Consumption (KW)			250
Pressure Drop (in H_20)			0.5
Pollutants			
	Inlet Loading (lb/hr)	Outlet Loading (lb/hr)	Control Efficiency %
Particulate Matter	5,346	25.8	99.5

Design Inlet loading calculation:
Uncontrolled: 5.19 lb/MMBtu x 1,030 MMBtu/hr = 5,346 lb/hr
ESP outlet loading (max) = 25.75 lb/hr (based on 0.025 lb/MMBtu)
ESP efficiency (min) = (5,346 - 25.75) / 5,346 = 99.5%

ATTACHMENT UC-EU1-I3c

CONTROL EQUIPMENT PARAMETERS FOR BOILER NO. 8
U.S. SUGAR CLEWISTON MILL

SELECTIVE NON-CATALYTIC REDUCTION SYSTEM

Manufacturer and Model No.	FuelTech		
Flue Gas Temp At Injections (^{o}F)			1,800-2,000
Flue Gas Flow Rate (acfm)			425,000
Moisture (% Volume)			24
No. of Injection Levels			3
Total No. of Injections			28
NO_x - OUT (urea) usage (max gal/hr)			76
Maximum Ammonia Slip (ppm)			20
Pollutants			
	Inlet Loading (lb/MMBtu)	Outlet Loading (lb/MMBtu)	Control Efficiency %
Nitrogen Oxides	0.28	0.14	50

ATTACHMENT UC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT UC-EU1-I4

CLEWISTON BOILER NO. 8

PROCEDURES FOR STARTUP AND SHUTDOWN

Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions will be taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 8. Boiler room foreman and operating personnel will receive proper training on emissions control procedures.

Cold Startup (approximately 6 to 12 hours)

1. Turn on wet cyclone.
2. Feed clean wood into boiler combustion chamber.
3. Start fire in combustion chamber using a propane torch designed for that purpose, or light a fuel oil or natural gas burner at the lowest rate.
4. Observe the stack plume and adjust if necessary, by adjusting fuel, atomizing air, and combustion air to obtain proper combustion.
5. Feed carbonaceous fuel from the mill to the boiler slowly.
6. Energize electrostatic precipitator (ESP).
7. Activate SNCR system.
8. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fossil fuel until burners can be turned off.
9. Continue to observe the stack plume, the cyclone water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, cyclone and ESP to maintain optimum operating conditions.
10. Normally, a cold startup will require 6 to 12 hours from the first fire to normal working pressure.

Hot Startup (approximately 1 to 5 hours)

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on wet cyclone
3. Check the boiler and cyclone water levels, and make sure they are functioning properly.

4. Light a fossil fuel burner, continue to observe the stack plume, cyclone water levels, and burners.
5. Feed carbonaceous fuel from the mill to the boiler slowly at first.
6. Energize ESP.
7. Activate SNCR system.
8. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fossil fuel until burners can be turned off. As the carbonaceous fuel fire gets hot enough to meet steam demand, reduce the fossil fuel supply until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
9. Continue to observe the stack plume, cyclone water level, and carbonaceous fuel level, making adjustments to drafts, fuel, cyclone and ESP to maintain optimum operating conditions.
10. Normally, a warm startup requires 1 to 5 hours, depending on boiler operating conditions.

Shutdown

1. Stop fuel flow to the boiler, reduce forced draft, distributor air, overfire air, and induced draft.
2. Continue to observe the stack plume and cyclone water levels and make adjustments to maintain safe and optimum operating conditions.
3. After fuel flow is stopped, deactivate ESP, wet cyclone, and SNCR system.

ATTACHMENT A

PROJECT DESCRIPTION

ATTACHMENT A

PROJECT DESCRIPTION

Boiler No. 8 at the United States Sugar Corporation (U.S. Sugar) Clewiston Mill is currently under construction. U.S. Sugar was issued Permit No. 0510003-021-AC/PSD-FL-333 on November 21, 2003 for the construction of Boiler No. 8. Construction on the boiler commenced shortly thereafter, and is currently ongoing. On November 4, 2004, U.S. Sugar was issued a revised construction permit (Permit No. 0510003-024-AC/PSD-FL-333A), which revised the shakedown period for the boiler and selective non-catalytic reduction (SNCR) control system, authorized periods of uncontrolled NO_x emissions, and authorized the firing of Dissolved Aeration Flotation (DAF) filter material.

The purpose of this application is to incorporate the provisions of the Boiler MACT rule. The U.S. Environmental Protection Agency (EPA) has issued maximum achievable control technology (MACT) standards to control the emissions of hazardous air pollutants (HAPs) from the burning of solid fuels in industrial boilers (codified under 40 CFR 63, Subpart DDDDD). To control emissions of HAP metals, a total particulate matter (PM) standard for new and existing solid fuel boilers of 0.025 and 0.07 pound per million British thermal units (lb/MMBtu) of heat input, respectively, is contained in the rule.

However, since EPA has recognized that PM emissions display a high variability based on boiler type and fuels, an alternative eight-metals standard [total selected metals (TSM) standard] has been included in the rule. The eight metals that are included in this standard are arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se). As an option to meeting the PM standard, sources can choose to demonstrate that the sum of the mass emissions rate of these eight metals is below 0.001 lb/MMBtu for existing boilers and 0.0003 lb/MMBtu for new boilers.

In addition to PM or TSM, the rule also regulates hydrogen chloride (HCl) and mercury (Hg) emissions. The emission limits for HCl are 0.02 lb/MMBtu for new solid fuel boilers and 0.09 lb/MMBtu for existing solid fuel boilers. The emission limits for Hg are 0.000003 lb/MMBtu for new solid fuel boilers and 0.000009 lb/MMBtu for existing solid fuel boilers.

Compliance with the PM emission limit is demonstrated through performance (compliance) tests, while compliance with the TSM, HCl, and Hg emission limits can be demonstrated by conducting performance (compliance) tests, or by fuel analysis.

Bagasse, a co-product of sugarcane processing, is used as a boiler fuel throughout Florida's sugarcane industry to supply steam for processing sugarcane into raw sugar. The U.S. Sugar Clewiston Mill currently has five operating bagasse/oil-fired boilers: Boiler Nos. 1, 2, 3, 4, and 7. These boilers burn solid fuel (bagasse), and therefore will be subject to the requirements and standards for existing solid fuel boilers (except for Boiler No. 3). The final compliance date for these existing boilers under Subpart DDDDD is September 13, 2007.

Existing Boiler No. 3 will be shut down in early 2005, upon commercial start-up of new Boiler No. 8, and therefore will not be subject to the MACT standards.

Boiler No. 8 will be subject to the new source MACT standards under Subpart DDDDD upon start-up of the boiler, since construction was commenced on Boiler No. 8 after January 13, 2003. The emission limits applicable to new solid fuel-fired boilers, and hence to Boiler No. 8, are as follows:

- PM – 0.025 lb/MMBtu, or as an alternative, TSM of 0.0003 lb/MMBtu;
- Hg – 3×10^{-6} lb/MMBtu;
- HCl – 0.02 lb/MMBtu; and
- CO – 400 ppmvd @ 7-percent O_2, 30-day rolling average.

U.S. Sugar proposes to meet the PM limit of 0.025 lb/MMBtu in lieu of meeting the TSM limit.

Potential emissions of HAPs from Boiler No. 8 have been updated based on the Boiler MACT rule. These are presented in Table 1, attached.

Compliance must be demonstrated for Boiler No. 8 within 180 boiler operating days after initial start-up, which is scheduled for late March 2005. U.S. Sugar will demonstrate compliance with Subpart DDDDD for Boiler No. 8 by several different methods. The proposed compliance plan and initial test plan (IPT) for Boiler No. 8 are described in Attachment B.

The Subpart DDDDD regulations applicable to Boiler No. 8 are presented in Attachment C. For each rule citation, a designation of "Y" for applicable, or "N" for non-applicable, is shown. The rationale for certain designations is presented in the table, as appropriate.

The proposed site-specific monitoring plan, which addresses the continuous monitoring systems (CMS) associated with Boiler No. 8, is presented in Attachment D.

Table 1. Estimated Potential HAP Emissions from Boiler No. 8, U. S. Sugar Corporation Clewiston Mill

Hazardous Air Pollutants	Carbonaceous Fuel Emission Factor (lb/MMBtu)	Ref.	Activity Factor [a] (MMBtu/yr)	Annual Emissions (TPY)
Organic HAPs				
Acetaldehyde	ND	1	6,767,100	--
Acrolein	ND	1	6,767,100	--
Benzene	8.0E-04	1	6,767,100	2.707
m-Cresol	ND	1	6,767,100	--
p-Cresol	ND	1	6,767,100	--
o-Cresol	ND	1	6,767,100	--
Cumene	ND	1	6,767,100	--
Ethylbenzene	ND	1	6,767,100	--
Formaldehyde	1.1E-03	1	6,767,100	3.722
Methanol	ND	1	6,767,100	--
Naphthalene [b]	1.8E-05	1	6,767,100	0.061
Phenol	1.1E-05	1	6,767,100	0.037
POMs	4.0E-05	1	6,767,100	0.135
Styrene	ND	1	6,767,100	--
Toluene	3.83E-05	1	6,767,100	0.130
1,1,2-Trichloroethane	ND	1	6,767,100	--
m- & p-Xylene	ND	1	6,767,100	--
o-Xylene	ND	1	6,767,100	--
Dibenzofurans	ND	1	6,767,100	--
bis(2-ethylhexyl)phthalate	4.2E-04	1	6,767,100	1.421
TOTAL ORGANIC HAPS [c]				8.152
Selected 8- Metals				
Arsenic	4.93E-05	2	6,767,100	0.083 [d]
Beryllium	7.47E-06	2	6,767,100	0.013 [d]
Cadmium	9.42E-06	2	6,767,100	0.016 [d]
Chromium	4.96E-05	2	6,767,100	0.084 [d]
Lead	3.09E-05	2	6,767,100	0.052 [d]
Manganese	1.01E-03	2	6,767,100	1.709 [d]
Nickel	3.20E-05	2	6,767,100	0.054 [d]
Selenium	8.92E-05	2	6,767,100	0.151 [d]
TOTAL 8-METALS				2.162
Mercury	3.00E-06	3	6,767,100	0.010
Hydrogen Chloride	0.02	3	6,767,100	67.67
Total HAPs [c]	--		--	**78.00**

Footnotes:

[a] Based on proposed annual heat input limitation.

[b] Individual member of the polycyclic organic matter (POM) category.

[c] Individual POM's were not included in total HAP calculation.

[d] 50% removal efficiency in wet scrubber/ESP control device assumed, based on stack testing.

ND = Not detected during emission tests or no data available.

References:

1. Based on HAP testing of Boiler No. 7. Geometric mean of three runs.
2. Represents average concentrations in bagasse, based on Clewiston Mill bagasse sampling program (2002-2003). control system.
3. Based on 40 CFR Part 63, Subpart DDDDD, Table 1.

ATTACHMENT B

INITIAL PERFORMANCE TEST PLAN
TO COMPLY WITH
40 CFR 63 SUBPART DDDDD

Boiler No. 8
U.S. Sugar, Clewiston Mill

SECTION PAGE

LIST OF TABLES

1.0 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) has issued maximum achievable control technology (MACT) standards to control the emissions of hazardous air pollutants (HAPs) from the burning of solid fuels in industrial boilers (codified under 40 CFR 63, Subpart DDDDD). To control emissions of HAP metals, a total particulate matter (PM) standard for new and existing solid fuel boilers of 0.025 and 0.07 pound per million British thermal units (lb/MMBtu) of heat input, respectively, is contained in the rule. However, since EPA has recognized that PM emissions display a high variability based on boiler type and fuels, an alternative eight-metals standard [total selected metals (TSM) standard], has been included in the rule. The eight metals that are included in this standard are arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se). As an option to meeting the PM standard, sources can choose to demonstrate that the sum of the mass emissions rate of these eight metals is below 0.001 lb/MMBtu for existing boilers and 0.0003 lb/MMBtu for new boilers.

In addition to PM or TSM, the rule also regulates hydrogen chloride (HCl) and mercury (Hg) emissions. The emission limits for HCl are 0.02 lb/MMBtu for new solid fuel boilers and 0.09 lb/MMBtu for existing solid fuel boilers. The emission limits for Hg are 0.000003 lb/MMBtu for new solid fuel boilers and 0.000009 lb/MMBtu for existing solid fuel boilers.

Compliance with the PM emission limit is demonstrated through performance (compliance) tests, while compliance with the TSM, HCl, and Hg emission limits can be demonstrated by conducting performance (compliance) tests, or by fuel analysis.

Bagasse, a co-product of sugarcane processing, is used as a boiler fuel throughout Florida's sugarcane industry to supply steam for processing sugarcane into raw sugar. The United States Sugar Corporation (U.S. Sugar) Clewiston Mill has currently has five operating bagasse/oil-fired boilers: Boiler Nos. 1, 2, 3, 4, and 7. Existing Boiler No. 3 will be shutdown in early 2005, upon commercial startup of new Boiler No. 8, which is now under construction.

Boiler No. 8 will be subject to the new source MACT standards upon start-up of the boiler. Start-up of the boiler is scheduled for late March, 2005. Compliance must be demonstrated for Boiler No. 8 within 180 boiler operating days of initial start-up.

Boiler No. 8 is permitted for a 1-hour maximum capacity of 550,000 lb/hr steam at a heat input rate of 1,036 MMBtu/hr. The 24-hour average capacity is limited to 500,000 lb/hr steam and 936 MMBtu/hr. The boiler will be fired primarily by bagasse, with No. 2 fuel oil used for startup, shutdown, malfunction, and as a supplemental fuel.

U.S. Sugar will demonstrate compliance with Subpart DDDDD for Boiler No. 8 by several different methods, including be stack testing and fuel analysis. Subpart DDDDD, and the general provisions (Subpart A) to 40 CFR Part 63, require that a site-specific test plan and fuel analysis plan be submitted to the reviewing agency within 60 days prior to conducting the IPT [40 CFR 63.7520(a) and 63.7521(b)].

The applicable Subpart DDDDD regulations, the proposed compliance plan, and the proposed initial performance test (IPT) plan for Boiler No. 8 are described in the following sections.

2.0 APPLICABLE LIMITS

Boiler No. 8, upon start-up, will be subject to new source standards under Subpart DDDDD, since construction was commenced on Boiler No. 8 after January 13, 2003. The emission limits applicable to new solid fuel-fired boilers are as follows:

- PM – 0.025 lb/MMBtu, or as an alternative, TSM of 0.0003 lb/MMBtu;
- Hg – $3x10^{-6}$ lb/MMBtu;
- HCl – 0.02 lb/MMBtu; and
- CO – 400 ppmvd @ 7-percent O_2, 30-day rolling average.

U.S. Sugar proposes to meet the PM limit of 0.025 lb/MMBtu, in lieu of meeting the TSM limit.

3.0 COMPLIANCE DEMONSTRATION AND PLAN

3.1 PARTICULATE MATTER (PM)

U.S. Sugar will demonstrate compliance with the PM standard for Boiler No. 8 by conducting stack testing using the following methods and procedures:

1. PM using EPA Method 5.
   a. A minimum of three test runs will be performed.
   b. Sampling time for each run will be a minimum of 60 minutes.
2. For determining sample port location and number of traverse points, EPA Method 1 or 1A will be used.
3. Velocity and volumetric gas flow rate measured out the stack using EPA Method 2, 2F, or 2G.
4. Oxygen concentration using EPA Method 3A or 3B. The gas sample must be taken at the same time and at the same traverse points as the PM sample.
5. Moisture content of stack gas using EPA Method 4.
6. Steam production rate, steam temperature and steam pressure, using process monitors.
7. Monitor voltage and secondary current and calculate total power input to the ESP. The voltage and secondary current to each field will be recorded at least once every 15-minutes. For each test run, the average total power input to the ESP will be determined. The minimum total power input for continuous compliance purposes will be set at 90 percent of the lowest test run average.

A total of three individual runs will be performed, with each run lasting for at least 1 hour. The average of the three test runs will be used to compare to the 0.025 lb/MMBtu limit. Testing will be conducted while Boiler No. 8 is operating at its normal maximum operating load (i.e., within 90 percent of permitted capacity, if such load is achievable). The F-factor methodology contained in 40 CFR 60, Appendix A, Method 19, Section 12.3.2, will be used to convert the measured PM concentrations to lb/MMBtu heat input emission rates. Fuel analysis, described in Section 3.2.2, will be used to develop the F-Factor during the test.

Since Boiler No. 8 employs a dry control system (ESP), but also additionally will employ a wet control system, the voltage and secondary current, or total power input, to the ESP must be utilized as operating parameters.

Initial performance tests for PM and HCl emissions from Boiler No. 8 will be conducted concurrently on the same day. These testing will be performed at an operating rate of at least 90 percent of the maximum permitted operating rate for the boiler, or the highest achievable operating rate, whichever is less. The exact test date has not yet been determined, but will occur in late March or early April 2005.

3.2 HYDROGEN CHLORIDE (HCL)

3.2.1 STACK TESTING

U.S. Sugar will demonstrate compliance with the HCl standard by conducting stack testing using the following test methods and procedures:

1. HCl using EPA Method 26A.
   a. A minimum of three test runs will be performed on each stack.
   b. Sampling time for each run will be a minimum of 60 minutes.
2. For determining sample port location and number of traverse points, EPA Method 1 or 1A will be used.
3. Velocity and volumetric gas flow rate measured of the stack gas using EPA Method 2, 2F, or 2G.
4. Oxygen concentration using EPA Method 3A or 3B. The gas sample must be taken at the same time and at the same traverse points as the HCl sample.
5. Moisture content of stack gas using EPA Method 4.
6. Steam production rate, steam temperature and steam pressure, using process monitors.
7. Monitor pressure drop across each wet scrubber. The pressure drop will be recorded at least once every 15-minutes across each wet scrubber. The device will have a minimum tolerance of 1.27 centimeters of water (0.5 inches of water). For each test run, the average pressure drop across each wet scrubber will be determined. The minimum pressure drop for continuous compliance purposes will be set at 90 percent of the lowest test run average.
8. Monitor scrubber liquid flow rate to each wet scrubber. The scrubber liquid flow rate to each wet scrubber will be recorded at least once every 15-minutes. The device will have a measurement sensitivity of 2 percent of the scrubbing liquid flow rate. For each test run, the average scrubber liquid flow rate will be determined. The minimum scrubber liquid flow rate for continuous compliance purposes will be set at 90 percent of the lowest test run average.
9. Monitor scrubber effluent pH from each wet scrubber. The pH of the scrubber effluent from each wet scrubber will be recorded at least once every 15-minutes. For each test run,

the average scrubber effluent pH will be determined. The minimum scrubber effluent pH for continuous compliance purposes will be set at 90 percent of the lowest test run average.

A total of three individual runs will be performed, with each run lasting for at least 1 hour. The average of the three test runs will be used to compare to the 0.02 lb/MMBtu limit. Testing will be conducted while Boiler No. 8 is operating at its normal maximum operating load (i.e., within 90 percent of permitted capacity, if such load is achievable). The F-factor methodology contained in 40 CFR 60, Appendix A, Method 19, Section 12.3.2, will be used to convert the measured HCl concentrations to lb/MMBtu heat input emission rates. Cl_2 gas emissions will also be reported in lb/MMBtu.

Since Boiler No. 8 employs a wet control system, the scrubber liquid flow rate, pressure drop across the scrubber, and the scrubber effluent pH must be utilized as operating parameters. U.S. Sugar will collect these data every 15 minutes during the performance testing on Boiler No. 8. The average parameter value will be determined for each individual run based on the once-every-15-minute readings. The minimum operating parameters for continuous compliance purposes will be set as 90 percent of the lowest test run average.

Initial performance tests for PM and HCl emissions from Boiler No. 8 will be conducted concurrently on the same day. These testing will be performed at an operating rate of at least 90 percent of the maximum permitted operating rate for the boiler, or the highest achievable operating rate, whichever is less. The exact test date has not yet been determined, but will occur in late March or early April 2005.

3.2.2 BAGASSE FUEL SAMPLING AND ANALYSIS

Subpart DDDDD requires that fuel sampling be conducted during performance testing for HCl emissions. The following sections present the sampling and analysis methodologies that will be employed by U.S. Sugar.

Methods

The final MACT rule requires the following steps for fuel analysis (40 CFR 63.7521):

1. Obtain at least three composite samples of each fuel type, following specific procedures;
2. Prepare each composite sample according to specific procedures; and
3. Determine pollutant concentrations in the fuel in pounds per million British thermal units (lb/MMBtu) of each composite sample.

The sample collection and laboratory methods will differ slightly from the requirements contained in the final MACT rule. A summary of the differences between the rule requirements and the procedures followed for the fuel sampling and analysis for the Boiler MACT testing at U.S. Sugar are presented in Table 3-1, and are described below.

Sample Collection, Storage, and Handling

Bagasse fuel sample collection will be performed during each stack test run (over approximately 1-hour discrete intervals) by U.S. Sugar Mill personnel during testing of Boiler No. 8. Three discrete bagasse samples will be taken at approximately the beginning, middle, and end of each run.

At the U.S. Sugar Mill, two tandems (a tandem is a series of grinding mills) are used to grind sugarcane, which produces bagasse fuel. The bagasse from each mill is dropped onto a conveyor belt after exiting the last grinding mill, and is then conveyed to the boilers. Boiler No. 8 is fed by the bagasse coming directly from the mills.

Boiler No. 8 has a total of eight bagasse feeders. Bagasse from the bagasse conveyor is fed from the conveyor belt directly to the feeders. Single grab samples will be taken from an access door located on each bagasse feeder. This will allow fuel samples to be taken of the bagasse going directly into the boiler. These grab samples will be composited. Composite samples will be obtained at the beginning, middle and end of each test run.

Note that it is not possible to "stop" the grinding mills or the bagasse conveyor belts at the Clewiston Mill without disrupting the milling operations, since the mills and conveyor belt directly feed the bagasse feeders on all the boilers. There is no intermediate storage of bagasse between the conveyor belt and the bagasse feeders. Therefore, the bagasse fuel sampling procedure will vary slightly from the Boiler MACT rule, which requires that the conveyor belt be stopped prior to taking the sample.

Grab samples will be taken at approximately the beginning, midpoint, and end of each sampling run, resulting in three grab samples per run. Each grab sample will consist of approximately 1 gallon of bagasse, or about 1.5 lbs of bagasse. Each grab sample of bagasse will be placed in a clean Ziploc® bag, stored in a cooler with ice, and transported to Golder Associates Inc. in Gainesville.

Golder's staff-members will composite the samples from the Clewiston Mill for each run, according to the procedures in the Boiler MACT rule, with minor deviations as noted in Table 3-1. The procedure that will be followed for the Clewiston Mill will vary from the Boiler MACT rule in that the samples will not be broken apart, since the bagasse is fairly uniform. In addition, the samples will not be ground because the bagasse has a small particle size. However, the lab will cut the samples prior to digestion and analysis. It is noted that the National Council for Air and Stream Improvement (NCASI) has identified grinding of samples as a possible point of sample contamination, due to the metals contained in the grinding equipment used in labs.

Throughout the sample collection, compositing, and delivery to the laboratories, the chain-of-custody will be documented.

Laboratory Analysis

Two laboratories will be used. One split sample will be sent to a laboratory (Hazen Research) for proximate, ultimate, chlorine, and heat content analyses. One split sample will be sent to a laboratory (PPB Environmental Laboratories) for metals analysis. The samples for metals analysis will be refrigerated or kept on ice until analyzed to prevent volatilization of metals (primarily Hg).

Bagasse analysis procedures will follow American Society for Testing and Materials (ASTM) methodologies for coal and coke analysis, modified for bagasse samples, as shown in Table 3-1. Preparation of the bagasse samples for analysis will be by Method 3050B from the Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Integrated Manuals (SW-846 (EPA, 1997).

The heat content analysis will be performed by using ASTM Method E711-87 (1996), and the solids (moisture) content analysis will utilize ASTM D3173-02. Both of these methods are specified in the rule.

Mercury concentrations, although not being stack tested, will be determined for the bagasse fuel by using SW846-7471A, which is the method specified in the rule.

Total selected metals concentrations, although not being stack tested or required to be analyzed for fuel testing, will be determined. Method SW846-6010B will be used. This method is approved under Subpart DDDDD for analysis of coal, and therefore should be applicable to bagasse, and equivalent to ASTM E885-88, which is the method specified in Subpart DDDDD for biomass.

Chlorine concentrations will be determined using ASTM D2361-02, which is equivalent to ASTM E776-87 (1996), the method specified in the rule. Sodium hydroxide will be used in the oxygen bomb. ASTM E776-87 allows the use of sodium hydroxide or potassium hydroxide (see Note 3 in the method). The chloride excess will be monitored and the endpoint found where the chloride content disappears.

Results

The F-factor will be calculated from the fuel analysis, based on the equation presented in EPA Method 19 of 40 CFR 60, Appendix A [as required by 40 CFR 63.7520(g)]. From the stack test results and the F-factor, the heat input to the boiler will be determined for each run.

The bagasse composite sample results for chlorine and Hg will be presented in parts per million (ppm) and lb/MMBtu. The heat contents in Btu/lb from the heat content analysis will be used to convert the metals content from ppm (as reported by the laboratory) to lb/MMBtu.

3.3 MERCURY (Hg)

U.S. Sugar will demonstrate compliance with the Hg limit specified in Subpart DDDDD by performing fuel sampling and analysis. The procedures that will be employed are described below. Also presented are historic Hg analysis data.

3.3.1 FUEL SAMPLING AND ANALYSIS METHODS DURING PERFORMANCE TESTING

The procedures described in Section 3.2.2 for fuel sampling and analysis will also be employed for Hg sampling and analysis during the performance tests.

3.3.2 HISTORIC FUEL SAMPLING

Sample Collection, Storage, and Handling

U.S. Sugar has previously collected bagasse samples from the Clewiston Mill. Sampling was performed over discrete 1-week intervals by Clewiston Mill personnel during the 2001-2002 and

2002-2003 sugarcane processing seasons. The bagasse sampling frequency and sampling methods used for internal quality control purposes at the Clewiston Mill were employed throughout the sampling period. Two milling tandems generate bagasse at the Clewiston Mill. Bagasse is generated in the milling process, and falls onto a conveyor belt after exiting the last mill in each tandem. The conveyor system directly feeds the boilers. Single grab samples were taken from the exit of each milling tandem, once per shift on each day during each sampling week. The grab samples were taken using a shovel device, which was moved across the width of the tandem to obtain a representative sample. The two grab samples from each milling tandem were combined to result in samples consisting of approximately 1 quart of bagasse.

This procedure resulted in weekly sample sizes ranging from about 34 to 42 grab samples (a few weeks were higher or lower). Each grab sample of bagasse was placed in a clean Ziploc® bag and stored in a refrigerator or freezer until picked up by a courier service. The courier service picked up the samples every Monday from the Mill and transported the samples to Gainesville. The samples were stored in coolers with ice while in transit.

Once the grab samples obtained for a sampling week were delivered to Gainesville, Golder staff composited the samples from the Mill for the entire week, thoroughly mixed the samples, and placed 2 or 3 sub-samples into new, clean Ziploc® bags. The samples were composited by placing individual grab samples onto clean plastic sheets and then hand mixing all of the samples. Once composited, several samples were created by extracting a small amount of bagasse from various locations in the composited pile. Each composite sample contained approximately 1 quart of bagasse.

One composite sample for each week was sent to Hazen Research for the proximate, ultimate, and heat content analyses. One composite sample from the mill for each week, plus a duplicate sample for the mill every fourth week (the duplicate samples were rotated between the four sugar mills each week) was sent to PPB Environmental Laboratories (PPB) for the metals analysis. The samples that were sent to PPB were refrigerated until analyzed to prevent volatilization of Hg. Beginning in the 2002-2003 crop season, composited samples were sent to Northeast Generation Services (NGS) Laboratory for chlorine analysis.

Throughout the sample collection, compositing, and delivery to the laboratories, the chain-of-custody was documented. A total of 21 sampling weeks were completed for the Clewiston Mill.

Laboratory Analysis

Hazen Research followed American Society for Testing and Materials (ASTM) methodologies for coal and coke analysis, modified for bagasse samples. The proximate analysis was performed by using ASTM Method D-3172, and the ultimate analysis was performed by using ASTM Method D-3176. Each of these methods were modified by heating the sample to 600 degrees Celsius (°C), rather than 800°C, for determining the percent ash in the samples. The heat content analysis was performed by using ASTM Method E711-87.

PPB used Method 3050B from the Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Integrated Manual SW-846 (EPA 1997) for the preparation of samples for the As, Be, Cd, Cr, Pb, Mn, Ni, and Se analyses. These samples were then analyzed using SW-846 Method 6010B. Hg samples were prepared and analyzed according to SW-846 Method 7471A. The solids (moisture) content analysis was performed according to SW-846 Method 160.3.

NGS followed ASTM Method D-4208 for the chlorine analysis.

Results

The laboratory results of the proximate, ultimate, heat content, and metals analyses for the U.S. Sugar Clewiston Mill are summarized in Tables 3-2 and 3-3. The individual sample results for the proximate, ultimate, and heat content analyses results for the 21 sampling weeks for the Clewiston Mill are presented in Table 3-2. Included in the table are the average moisture, ash, volatile matter, heating value, carbon, nitrogen, hydrogen, sulfur, oxygen, and sulfur dioxide content on a dry basis.

As shown in Table 3-2, the proximate, ultimate, and heat content analyses are similar for each sampling week. The bagasse moisture content ranged from 49.0 to 55.1, averaging 51.6 percent. The weekly ash contents showed wider variation, ranging from 0.87 to 8.40 percent, with an average of 4.5 percent. Weekly heating values ranged from 7,602 British thermal units per pound (Btu/lb) to 8,356 Btu/lb (dry basis), with an average of 7,920 Btu/lb. Weekly sulfur contents were all similar, varying from 0.03 to 0.09 percent, with an average of 0.06 percent.

For informational purposes, the F-factor was calculated and included in Table 3-2. The F-factor was calculated based on the equation presented in the EPA Method 19 of 40 CFR 60, Appendix A [as required in 40 CFR 63.7520(g)].

The individual weekly results of the metals analyses for chlorine, As, Be, Cd, Cr, Pb, Mn, Hg, Ni, and Se in parts per million (ppm) and lb/MMBtu, and the moisture content, are presented in Table 3-3. The heat content in Btu/lb from the proximate/ultimate analysis was used to convert the metals content from ppm (as reported by the laboratory) to lb/MMBtu. The sum of the eight metals (TSM) is also shown for comparison to the TSM standard in Subpart DDDDD (although Boiler No. 8 will be demonstrating compliance with the PM standard).

The final rule requires the use of the 90-percent confidence level of the fuel analysis data when comparing fuel analysis results to the emission limits contained in the rule [40 CFR 63.7530(d)(2)]. The 90-percent confidence level was calculated for TSM, Hg, and HCl. Therefore, the upper 90-percent confidence level of the data was calculated.

It is noted that many of the individual metal analyses resulted in concentrations below minimum detectable limits. In such cases, the minimum, maximum, and average concentrations were calculated by taking one-half of the detectable level for each sample.

As shown in Table 3-3, the average bagasse TSM concentration for the Clewiston Mill for the sampling period was 0.00125 lb/MMBtu and the 90-percent confidence level was 0.00168 lb/MMBtu. This is above the 0.001 lb/MMBtu alternative TSM standard for existing boilers. As shown, Mn represents the major fraction of the TSM total, averaging just greater than 0.001 lb/MMBtu for the Clewiston Mill.

Hg concentrations from all individual sampling weeks except one were reported to be less than the detectable levels. Initially, analyses were conducted which resulted in detectable limits which were greater than the Hg emission standards. Therefore, the minimum detectable limit was lowered. The average Hg concentration for the five sampling weeks with the lower Hg detection limit was calculated to be less than $1.0\text{x}10^{-6}$ lb/MMBtu, based on one-half the minimum detectable limit for the samples that were below detectable limits. The 90-percent confidence level was calculated to be $1.77\text{x}10^{-6}$ lb/MMBtu. This is below the Hg emission limit contained in the rule for new boilers of $3\text{x}10^{-6}$ lb/MMBtu.

As shown in Table 3-3, the bagasse chlorine concentrations ranged from 0.048 to 0.086 lb/MMBtu, with an average of 0.065 lb/MMBtu. The 90-percent confidence level was calculated to be 0.093 lb/MMBtu. HCl was calculated by multiplying the 90-percent confidence level for chlorine by

1.028 [40 CFR 63.7530(d)(3)]. The 90-percent confidence level for HCl was calculated to be 0.096 lb/MMBtu. This is above the HCl emission limit contained in the rule for new boilers of 0.02 lb/MMBtu.

Deviations from Final Rule

Since the fuel analysis was conducted based on the proposed Boiler MACT rule and prior to issuance of the final rule, the sample collection and compositing and laboratory methods differed somewhat from the requirements contained in the final rule. A summary of the differences between the rule requirements and the procedures followed during the fuel analysis study are summarized in Table 3-4 and are described below.

The final rule requires the following steps for fuel analysis:

1. Obtain at least three composite samples of each fuel type, following specific procedures;
2. Prepare each composite sample according to specific procedures; and
3. Determine pollutant concentrations in the fuel in lb/MMBtu of each composite sample.

The first step in fuel analysis procedures is to obtain at least 3 composite samples of each fuel type following the specified procedures. The sampling procedure in the rule requires that the conveyor belt be stopped and a 6-inch wide sample be withdrawn from the fuel cross-section of the belt to obtain a minimum of 2 pounds of sample, collect all material in the cross-section, and transfer to a clean plastic bag. Each composite sample must consist of at least 3 samples collected at approximately equal intervals during the testing period.

The procedures followed during the historic fuel sampling at the Clewiston Mill included taking single grab samples from the bagasse stream exiting each milling tandem at approximately equal intervals 5 to 7 times per day. At the Clewiston Mill, it is impractical to stop the tandems or the conveyor belt carrying bagasse to the boilers in order to take a sample. Stopping the tandems or conveyor belt would result in a disruption to the bagasse feed to the boilers, since the tandems and conveyor belt directly feed the boiler bagasse feeders. This would result in an immediate drop in steam production, and would create a disruption to the sugar mill operations.

The samples were collected and stored in quart-size plastic storage bags and refrigerated. Each composite sample consisted of approximately 34 to 42 individual grab samples, which is much greater than the required 3 samples. Therefore, the composite samples represented a much greater mass of bagasse fuel over a much greater time period.

The second step, prepare each composite sample according to the specified procedures, includes thoroughly pouring and mixing the entire composite sample over a clean plastic sheet, breaking sample pieces over 3 inches into smaller sizes, making a pie shape of the sample and subdividing it into 4 equal parts, separate one of the quarter samples, and grinding the sample in a mill. The procedure that was followed for the Clewiston Mill varied in that the samples were not broken apart since the bagasse was fairly uniform, the representative composite samples were taken from various locations in the sample pile, and the samples were not ground. However, the lab cut the samples prior to digestion and analysis.

The final rule contains specific analytical procedures for sample preparation and determining the heat content, moisture content, and pollutant concentrations. The specified method, equivalent, or similar methods were used in the laboratory analysis for the Clewiston Mill. The method used for the preparation of the fuel samples was SW846-3050B, which is the method specified in the rule. The method used for determining the heat content was ASTM E711-87 (the method specified in the rule). The method used for determining the moisture content was by Hazen Research was ASTM D-3173-02, which is the method specified in the rule. The method used by PPB Labs was SW846 Method 160.3.

Mercury concentration was determined using SW846-7471A, which is the method specified in the rule. TSM concentration was determined using SW846-6010B, which is the method specified in the rule for coal, while the method specified in the rule for biomass is ASTM E885-88. Both methods are similar methods, but may use different equipment. SW846-6010 is an industry standard for this type of analysis because it yields faster results and has lower detection limits. Since SW846-6010B is approved for analysis of coal, it should be acceptable for bagasse as well.

Chlorine was determined using ASTM D-4208, while the rule specified either SW846-9250 or ASTM E776-87. Both ASTM D-4208 and E-776-87 are oxygen bomb methods, but the methods differ somewhat.

Although some of the sampling, compositing, and analytical procedures differed somewhat from those specified in the final rule, it is believed that the results would not have been significantly different if the procedures contained in the rule were expressly followed. This is due in part to the large number of samples obtained during the study.

Conclusions

A comprehensive sampling and analysis study of bagasse fuel burned at the U.S. Sugar Clewiston Mill was undertaken. Approximately 800 individual bagasse samples were taken over a 21-week period. Based on the results of this study, emissions from the Clewiston Mill bagasse boilers are below the Hg standard of 3×10^{-6} lb/MMBtu, but above the HCl standard of 0.02 lb/MMBtu, for new boilers, based on fuel analysis. The 90-percent confidence level Hg and HCl concentrations from this study were less than 1.77×10^{-6} lb/MMBtu and 0.096 lb/MMBtu, respectively.

The reported concentration values represent the concentrations in the bagasse fuel, and not the emissions from the boilers. The flue gases from Boiler No. 8 will pass through a wet scrubber and ESP before being exhausted out of the stack. The control devices will remove a large portion of the metals and HCl in the flue gases, since the eight metals of interest exist in the solid phase (as fly ash) in the flue gases, and the control devices are highly effective in removing other acid gases such as sulfur dioxide, as demonstrated through stack testing. In addition, some metals will be contained in the bottom ash, which exits the boiler through the bottom ash removal system. Therefore, actual emissions out of the stack are expected to be much less than the equivalent emissions in the fuel.

3.4 DATA QUALITY OBJECTIVES

U.S. Sugar expects to follow the precision and accuracy that is required in the Boiler MACT requirements and the specific test methods in the rule. U.S. Sugar expects to have a complete set of performance test data, including calculations, as outlined in this test plan, by the time that the initial performance test plan reports are submitted. These reports will be submitted as part of the Notification of Compliance Status required by 40 CFR 63.7545(e) and 63.9(h)(2)(ii).

3.5 INTERNAL AND EXTERNAL QUALITY ASSURANCE

3.5.1 INTERNAL QUALITY ASSURANCE

U.S. Sugar has implemented the following quality assurance (QA) procedures, which will also be followed during the Boiler No. 8 performance testing:

- Equipment is calibrated at least annually;
- Gauges are checked at least annually;
- Systems are inspected prior to testing;
- Flow meters are calibrated at least annually; and
- Malfunctioning equipment is repaired and recalibrated as soon as practicable.

3.5.2 EXTERNAL QUALITY ASSURANCE

The stack testing company that will be performing the testing is Air Consulting & Engineering (ACE). The ACE quality assurance (QA) program is broken down into the following categories:

Pretest

Calibrations

ACE uses a Precision Analytical Model 63123 meter as a calibration standard. The wet test meter is operated at one cubic foot per revolution. Calibrations are performed at five points in triplicates according to United States Environmental Protection Agency (EPA) specifications. Calibration checks are performed annually at two calibration points in triplicate (EPA requires only one reading per point).

All original calibration data and updates as well as the calibration curve, are presented in the QA section of all ACE reports.

Field meters are calibrated against this standard annually or after 200 hours of use (whichever occurs first). The field meters are recalibrated anytime a post calibration test check yields results which deviate by more that two percent (EPA requires recalibration at ±5 percent). ACE participates in EPA's Emission Monitoring Laboratory voluntary audit program.

The thermometers, pyrometers, and thermocouples are calibrated annually and spot checked frequently (post test calibrations). When physically possible, field checks are made by comparison to a mercury-in-glass thermometer in the field under stack conditions.

Pitot tubes are constructed to EPA specifications and are calibrated by measurement technique. Each pitot is visually inspected for proper alignment and possible damage prior to each use.

All calibration data are included in the QA section of ACE reports. Calibration logs are maintained and are available for inspection at our office in Gainesville, Florida.

Analytical Instruments

All instruments used by ACE for compliance testing and CEM certification have been approved by the EPA for such use. Manufacturers' recommended calibration and maintenance procedures are strictly adhered to. Documentation of each instrument's Performance Specifications, Interference Response, and Accuracy Verification are included in each report.

Calibration Gases

ACE uses National Bureau of Standards (NBS) traceable calibration gases. These gases have been analyzed according to EPA Protocol 1. A Certification of Protocol Analysis for all calibration gases is provided in each report.

Tare Weights

Particulate filters and beakers are tare weighed in ACE's Gainesville, Florida, laboratory weight room. The weight room is humidity controlled and maintained at 30 to 50 percent relative humidity. Our balance is a Mettler H10 Model. It is services and calibrated annually or as needed by Weight Check, Inc. of Jupiter, Florida.

Filters are visually inspected for irregularities, numbered, oven fired at 200°F for two hours and desiccated for 24 hours.

Beakers are washed with warm, soapy water, rinsed with tap water, and, finally, rinsed with distilled water. They are then drip-dried, oven-dried at 200°F for two hours, and desiccated for 24 hours.

Prior to use the Mettler level bubble is checked and the balance is zeroed. Linearity is checked with 0.5, 10.0, and 100.0 gram Type S certified weights. The certified weight checks along with temperature, humidity, date, time, and technician's name performing the weighing are recorded in the tare weight book. Filters and beakers are then weighed and recorded in the tare weight book. The weighed items are then replaced in desiccators and reweighed at a minimum of six hours elapsed time. Weights that vary no more than 0.5 mg are considered constant. Two acceptable weighings are averaged for the final tare weight. One out of ten filters and beakers are later analyzed by the QA officer. Beakers are kept in desiccators until needed. Filters are either placed directly in sealed filter holders for field use or sealed in Petri dishes and Ziploc® bags for future use.

Sample Bottles

Sample bottles are washed with warm, soapy water, rinsed with tap water, and finally rinsed with distilled water. The bottles are then visually inspected for particulate residue and allowed to air-dry. They are then tightly sealed and taped for use in the field.

Silica Gel

Upon purchase, silica gel is inspected for proper color and mesh size. ACE pre-weighs all silica gel to exactly 200 grams in the field containers, including the lids. This prevents possible silica gel pre-test weight errors. The silica gel containers are then tightly sealed and stored for field use.

Acetone or Distilled Water

Before opening a new container of rinse reagent, it is thoroughly shaken, and three 100-milliliter aliquots are taken. These samples are treated as field blanks to ensure the quality of our cleanup reagents. Bad acetone is returned to the supplier.

In the Field

ACE's field team leader is responsible for all QA in the field.

Leak Checks

ACE places emphasis on pre-test leak checks. The meter box is leak-checked (inclusive of post-pump portions) at 15+ inches of H_2O pressure, respectively, to ensure meter integrity during transit.

Both sides of the pitot tube are leak-checked at 3+ inches of H_2O pressure.

The Orsat analyzer and integrated bag are checked under pressure by observation over a 10-minute period.

When the sampling train is assembled, all components are leak-checked at 15+ inches of Hg vacuum.

If any leaks are detected, they are corrected before any sampling is initiated. All required leak checks are repeated after each sampling run.

Nozzle Calibration

Nozzle calibration is performed in the field by the field team leader. Three different diameters of the nozzle opening are measured with calipers and averaged. These measurements are recorded on the first page of the field data sheet.

Field Testing

The numbers of the filter, silica gel, meter box, pyrometer, and pitot-thermocouple are recorded prior to testing. The names of the test participants, coordinator, and agency observers are also recorded on the field data sheets.

The barometric pressure is obtained from an aneroid barometer taken to the sampling platform. This eliminates need for altitude corrections. The barometer is calibrated against the mercury barometer used by the United States Weather Service at the Gainesville Regional Airport (approximately 1.5 miles from our laboratory) and is spot checked for accuracy after each test in the post test calibration.

Field calculations are made at the conclusion of each sample run to insure isokinetic limits have been met and that moisture content and flow rates are within the expected performance of the unit tested. This procedure detects any tube leaks and fan imbalances that can be detrimental in meeting compliance standards.

Sample Recovery

Upon completion of a sample run, the probe is placed in a secure position and the exterior of the nozzle is carefully wiped clean. After the leak check, the nozzle is removed and rinsed with acetone (or water) into a prepared sample bottle. The nozzle is then thoroughly brushed and rinsed until all particulate has been captured. The sample bottle is then securely closed and the liquid level is marked. The bottle is labeled with the plant name, source number, run number, and date. It is then placed in an upright position in the sample box.

The condensate collected in the first, second, and third impingers is carefully measured and recorded on the first page of the field data sheet. Any unusual characteristics (color, odor, etc.) are noted. The silica gel in the fourth impinger is carefully recovered and placed in its original container and labeled with the plant name, source name, run number, and date.

Used silica gel is also kept in the sample box.

The filter holder is then removed from the probe. It is securely sealed at both ends and labeled as the sample bottle. All filter recovery, if possible, is performed at ACE's laboratory.

If filter recovery in the field is required, the filter holder is taken to a clean environment, usually the mobile CEM lab or the sampler's motel room, and the exterior is cleaned to prevent contamination. The holder is carefully opened and the filter is removed. A spatula and nylon bristled brush are used to recover any pieces of the filter adhering to the gasket or filter holder. The filter is placed in a plastic Petri dish, sealed, and labeled. The sample side of the holder is then washed and thoroughly brushed. The wash is added to the nozzle wash sample bottle and the liquid level is remarked. All samples are kept in the sample box.

Blanks

A filter and acetone, sample blank are taken in the field during sample recovery. Care is taken to ensure the blank samples have received the same treatment as field samples. Blanks are transported and treated in the same manner as field samples.

<u>Post Test</u>

Analysis

Nozzle, probe, and filter holder washes are checked for liquid loss. They are then thoroughly shaken and poured into tared beakers. The container is rinsed with acetone or water and the contents are added to the beaker. The total volume is recorded on the laboratory data sheet. Beakers are evaporated to dryness at ambient temperature and pressure, oven dried at 200°F for two hours, and finally desiccated until cool.

Filters are placed in glass Petri dishes; oven dried at 200°F for two hours; and desiccated until cool. Final weights are determined using the same procedure as the tare weighing process. Time, date, temperature, humidity, Type S weight results, and the name of the technician are recorded on the laboratory data sheet for each weighing. Two such determinations and the average are shown on the laboratory data sheet.

Bagasse heat content and chlorine content will be determined by Hazen Research, Inc. Lab analysis for HCl for Method 26A will be performed by Pace Laboratories.

Chain of Custody

The chain of custody is initiated at the time of sample recovery. Run number, container number, liquid level check, color of sample, and comments are all noted on the chain of custody sheet. Silica gel data is also included on this sheet. Technicians performing recovery and analysis sign the bottom of the chain of custody sheet. This sheet is included in the QA section of all ACE's reports.

Post-test Calibrations

Post test calibration checks are performed on the dry gas meter, the meter temperature thermometer, the stack thermocouple, and the barometer. These checks are made under conditions approximating the actual field test.

The meter is checked in triplicate at the maximum vacuum encountered during sampling. The stack thermocouple is compared to a mercury-in-glass thermometer at the average stack temperature and the meter temperature is checked at ambient conditions prior to meter use. The post test calibration sheet is signed by the technician performing the calibrations and is included in all ACE stack reports.

Reports

ACE uses a report format that is acceptable to all regulatory agencies. ACE reports are written by a principal or engineer (of ACE) and are reviewed by a designated QA professional for data and document accuracy. Each report contains a signed statement by a principal or engineer of ACE attesting to the authenticity of the test and the report.

3.6 CALCULATIONS

The PM and HCl stack mass emission rates will be converted to lb/MMBtu units using the following equation:

E = lb/hr ÷ MMBtu/hr (lb/MMBtu)

Where:

E = the emission rate in terms of the MACT standard

lb/hr = the measured mass emission rate of PM or HCl

MMBtu/hr = the heat input to the boiler based on the F-factor

3.7 REPORTING

The results of the stack tests will be submitted to DEP within 45 days of completion of the tests while the results of the initial performance test will be submitted to the Administrator before the close of business on the 60th day following the completion of the performance test. The report will include:

- The PM and HCl emissions results for Boiler No. 8 determined from the initial performance test;
- The calculations and supporting documentation used to determine the PM and HCl emission rates;
- The minimum values for wet scrubber and ESP operating parameters, established during these initial performance tests; and
- Data and information demonstrating good quality assurance.

Table 3-1. Comparison of Proposed Boiler No. 8 Bagasse Fuel Sampling and Analysis Procedures With Final Boiler MACT Rule

Rule Citation	Boiler MACT Rule Requirement	U.S. Sugar's Procedures/Methods
	BAGASSE FUEL SAMPLING PROCEDURES	
63.7521(c)	**Must obtain at least 3 composite samples of each fuel type, following these procedures for a belt/screw feeder:**	Collect a composite sample during each individual test run.
	1. Stop belt and withdraw 6-inch wide sample from fuel cross-section of belt to obtain a minimum of 2 lbs. of sample. Collect all material in full cross-section. Transfer to clean plastic bag.	Grab samples will be taken from the access door located on each bagasse feeder feeding Boiler No. 8. These grab samples will be composited into a single sample. This will provide a representative sample of the bagasse directly entering the boiler. A total grab sample of approximately 1-gallon will be obtained (approx. 1.5 lbs). The samples will be collected and stored in a plastic bag and refrigerated until shipped to Golder for compositing.
	2. Each composite sample must consist of at least 3 samples collected at approximately equal intervals during testing period.	Each composite sample will consist of three (3) individual grab samples as described in Step 1 above, obtained at equal intervals over the test run.
63.7521(d)	**Prepare each composite sample according to these procedures:**	
	1. Thoroughly mix and pour entire composite sample over a clean plastic sheet.	Consistent with rule.
	2. Break sample pieces over 3 inches into smaller sizes.	Not necessary since bagasse fuel has already been ground in the sugar mill grinding mills.
	3. Make a pie shape with entire composite sample and subdivide it into 4 equal parts.	Consistent with rule.
	4. Separate one of 1/4 samples as first subset.	Consistent with rule.
	5. If subset is too large for grinding, repeat step #3.	Not applicable.
	6. Grind sample in a mill.	Will not grind the samples, since not necessary due to small particle size of bagasse fuel. Lab will cut the samples prior to digestion as necessary.
	7. Use step #3 to obtain a 1/4 subsample for analysis.	Consistent with rule.
	8. If 1/4 sample is too large, subdivide it further using same procedure.	Consistent with rule.
63.7521(e)	**Determine pollutant (Hg, HCl, and/or TSM) concentrations in fuel in lb/MMBtu of each composite sample.**	Proximate, ultimate, heat content, metals, and chlorine analyses will be performed. All pollutants will be calculated in lb/MMBtu based on heat content.
	BAGASSE FUEL ANALYTICAL PROCEDURES	
Table 6	1. Collect fuel samples--63.7521(c) or ASTM D6323-98 (2003) or equivalent	see above for differences in procedure
	2. Composite fuel samples--63.7521(d) or equivalent	see above for differences in procedure
	3. Prepare composited fuel samples--SW846-3050B or ASTM D5198-92 (2003) or equivalent	SW846-3050B
	4. Determine heat content of fuel type--ASTM E711-87 (1996) or equivalent	ASTM E711-87 (1996)
	5. Determine moisture content of fuel type--ASTM D3173-02 or ASTM E871-82 (1998) or equivalent	ASTM D3173-02
	6. Measure pollutant concentration in fuel sample:	
	--Mercury--SW-846-7471A	SW846-7471A
	--Total selected metals--ASTM E885-88 (1996)	SW846-6010B. This method is approved under Subpart DDDDD for use on coal. We therefore believe it is applicable to bagasse and is equivalent to ASTM E885-88. SW646-6010B is the industry standard beause it yields faster results and has lower detection limits.

Table 3-1. Comparison of Proposed Boiler No. 8 Bagasse Fuel Sampling and Analysis Procedures With Final Boiler MACT Rule

Rule Citation	Boiler MACT Rule Requirement	U.S. Sugar's Procedures/Methods
	--Chlorine--SW-846-9250 or ASTM E776-87 (1996) or equivalent	ASTM D-2361-02, with sodium hydroxide used in the oxygen bomb. Equivalent to ASTM E776-87, which allows sodium hydroxide instead of potassium hydroxide (see Note 3 in the method). The chloride excess is monitored and the endpoint found where the chloride content dissappears.
	7. Convert concentrations into units of lbs pollutant/MMBtu of heat content	Converted using concentrations in ppm and heat content.
	STACK TESTING PROCEDURES	
Table 5	**PARTICULATE MATTER AND HYDROCHLORIC ACID:**	
	1. Select sampling ports location and number of traverse points.--Method 1	Method 1
	2. Determine velocity and volumetric flow rate of stack gas--Method 2, 2F, or 2G.	Manual method (incorporated into pollutant emission Methods)
	3. Determine oxygen and carbon dioxide concentrations of the stack gas--Method 3A or 3B or ASME PTC 19, Part 10 (1981)	Manual method 3A (incorporated into pollutant emission Methods)
	4. Measure moisture content of stack gas--Method 4	Manual method (incorporated into pollutant emission Methods)
	5. Measure pollutant emission concentrations:	-
	--PM emission concentration--Method 5 or 17 (positive pressure fabric filters must use Method 5D)	Method 5
	--total selected metals emission concentration--Method 29	Not applicable; no testing for TSM.
	--hydrogen chloride emission concentration--Method 26 or 26A	Method 26A; also measures for chlorine gas
	--mercury emission concentration--Method 29, Method 101A (Appendix B), or ASTM Method D6784-02	Not applicable; no testing for mercury.
	6. Convert emissions concentration to lb/MMBtu emission rates--Method 19 F-factor methodology	Method 19 F-Factor methodology.

Table 3-2. Proximate, Ultimate, and Heat Content Analyses Results for Bagasse from U.S. Sugar Clewiston

Parameter	Units	Analysis Results (dry basis) for Sample Weeks (collection dates)										
		1/14 - 1/20/02	1/21 - 1/27/02	1/28- 2/03/02	2/4- 2/10/02	2/11- 2/17/02	2/18- 2/24/02	2/25- 3/3/02	3/4- 3/10/02	3/11- 3/17/02	3/18- 3/24/02	3/25- 3/31/02
No. of Samples Composited		39	42	41	42	43	39	41	42	41	42	41
Moisture	%, as received	52.86	52.01	50.49	50.06	48.99	50.31	50.18	50.84	51.32	51.60	52.56
Ash	%	4.04	2.95	5.32	5.04	5.14	3.61	3.15	2.61	3.90	3.23	3.74
Ash	lb/MMBtu	5.10	6.54	6.80	6.39	6.54	4.48	3.98	3.25	4.91	4.03	4.65
Volatiles	%	85.41	86.38	83.24	82.86	83.42	84.52	85.49	87.68	87.31	84.04	84.82
Fixed C	%	10.55	10.67	11.44	12.10	11.44	11.87	11.36	9.71	8.79	12.73	11.44
HHV	Btu/lb	7,922	7,978	7,824	7,884	7,852	8,073	7,911	8,037	7,953	7,994	8,058
MMF	Btu/lb	8,284	8,240	8,301	8,338	8,313	8,401	8,189	8,270	8,303	8,283	8,397
MAF	Btu/lb	8,256	8,220	8,264	8,303	8,277	8,376	8,168	8,253	8,276	8,261	8,372
Air Dry Loss	%	52.23	51.65	50.00	48.75	48.30	49.83	49.58	50.05	49.85	50 75	51.98
Carbon	%	47.50	47.65	47.06	46.94	46.78	47.75	48.12	48.26	47.63	48.34	47.54
Hydrogen	%	5.67	5.60	5.63	5.54	5.88	5.98	6.10	6.49	6.00	6.31	6.44
Nitrogen	%	0.36	0.38	0.36	0.38	0.33	0.40	0.36	0.41	0.38	0.38	0.41
Sulfur	%	0 06	0.05	0.07	0.03	0.07	0.07	0.04	0.04	0.04	0.05	0.07
Oxygen	%	42.37	43.37	41.56	42.07	41.80	42.19	42.23	42.19	42.05	41.69	41.80
SO_2	lb/MMBtu	0.15	0.13	0.18	0.08	0.18	0.18	0 10	0.10	0.10	0.13	0.18
F-Factor												
Fd	dscf/MMBtu	9,329	9,203	9,390	9,221	9,403	9,354	9,667	9,722	9,487	9,736	9,562

Parameter	Analysis Results (dry basis) for Sample Weeks (collection dates)										Range			
	11/25- 12/1/02	12/9- 12/15/02	12/23- 12/29/02	1/6- 1/12/03	1/20- 1/26/03	2/3- 2/9/03	2/17- 2/23/03	3/3- 3/9/03	3/17- 3/23/03	3/31- 4/6/03	Min	Max	Avg	Parameter
No. of Samples Composited	39	23	26	42	28	36	34	38	26	32	--	--	--	
Moisture	54.16	51.20	50.98	51.48	51.66	51.12	51.56	52.96	52.84	55.07	48.99	55.07	51.63	Moisture
Ash	0.87	8.40	6.39	7.30	6.65	3.31	4.19	4.12	5.56	5.60	0.87	8.40	4.53	Ash
Ash	6.00	10.96	8.09	9 54	8.75	4.17	5.02	5.21	7.05	7.16	3.25	10.96	6.12	Ash
Volatiles	83.75	79.86	80.89	81.43	81.59	83.90	83.65	85.91	82.98	82.33	79.86	87.68	83.88	Volatiles
Fixed C	11.38	11.74	12.72	11.27	11.76	12.79	12.16	9.97	11.46	12.07	8.79	12.79	11.40	Fixed C
HHV	8,118	7,664	7,900	7,658	7,602	7,936	8,356	7,896	7,878	7,827	7.602	8,356	7,920	HHV
MMF	8,568	8,428	8,486	8,313	8,190	8,230	8,752	8,264	8,381	8,330	8,189	8,752	8,346	MMF
MAF	8,533	8,366	8,440	8,261	8,143	8,208	8,722	8,236	8,342	8,291	8,143	8,722	8,313	MAF
Air Dry Loss	53.59	50.56	49.72	50.64	50.85	50.26	50.97	52.53	52.19	54.07	48.30	54.07	50.87	Air Dry Loss
Carbon	48.26	46.35	46.64	46 11	49.51	50.79	50.94	49.91	49.23	48.88	46.11	50.94	48.10	Carbon
Hydrogen	5.23	4.71	5.24	4.90	6.39	5.86	6.39	6.62	6.46	6.59	4.71	6.62	5.91	Hydrogen
Nitrogen	0.29	0.25	0.34	0.33	0.33	0.33	0.31	0.38	0.30	0.30	0.25	0.41	0.35	Nitrogen
Sulfur	0.09	0.05	0.05	0.07	0.07	0 09	0.08	0.06	0.07	0.09	0 03	0.09	0.06	Sulfur
Oxygen	41.26	40.24	41.34	41.29	37.05	39.62	38.09	38.91	38.38	38.54	37.05	43.37	40.86	Oxygen
SO_2	0.22	0.13	0.13	0.19	0.19	0.23	0.19	0.15	0.18	0.24	0.08	0.24	0.16	SO_2
F-Factor														
Fd	9,114	9,083	9,050	9,072	10.794	10,195	10,025	10,467	10,315	10,367	9,050	10,794	9.646	Fd

Note: % = percent.
Btu/lb = British thermal unit per pound
C = carbon.
HHV = higher heating value.
lb/MMBtu = pounds per million British thermal unit.
MAF = moisture and ash free; dry basis heating value without ash included.
MMF = mineral and matter free; heating value without sulfur and ash included.
SO_2 = sulfur dioxide.

Table 3-3. Metals and Chlorine Analyses for Bagasse from U.S. Sugar–Clewiston

Parameter	Units	Concentration (dry basis) for Sample Weeks (collection dates) 1/14-1/20/02	1/14-1/20/02 Duplicate	1/21-1/27/02	1/28-2/3/02	2/4-2/10/02	2/11-2/17/02	2/11-2/17/02 Duplicate	2/18-2/24/02	2/25-3/3/02	3/4-3/10/02	3/4-3/10/02 Duplicate	3/11-3/17/02	3/18-3/24/02	3/25-3/31/02	3/25-3/31/02 Duplicate	11/25-12/1/02	12/9-12/15/02	12/23-12/29/02	12/23-12/29/02 Duplicate	1/6-1/12/03	1/20-1/26/03	2/3-2/9/03
Chlorine	ppm	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	394.45	441.91	376.65	--	534.44	391.10	663.94
Arsenic	ppm	0.6	0.6	0.5	0.5	< 0.4	0.3	0.2	0.2	0.3	0.4	0.4	< 0.3	0.4	0.3	0.4	0.4	--	0.3	0.5	--	< 1.8	--
Beryllium	ppm	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	--	< 0.1	< 0.1	--	< 0.2	--
Cadmium	ppm	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	--	< 0.1	< 0.1	--	< 0.3	--
Chromium	ppm	0.4	0.6	0.2	0.3	0.6	0.5	0.4	0.2	0.3	0.5	0.8	0.2	0.3	0.2	0.2	0.8	--	0.5	0.6	--	0.6	--
Lead	ppm	0.3	0.2	< 0.3	< 0.3	< 0.4	< 0.3	< 0.3	< 0.3	0.2	< 0.3	0.3	< 0.3	< 0.3	< 0.3	< 0.3	< 0.2	--	0.4	0.4	--	< 1.8	--
Manganese	ppm	8.1	7.5	7.2	8.9	7.4	8.2	8.0	6.2	5.6	8.0	8.9	5.8	6.3	10.9	11.8	9.5	9.9	7.8	9.6	10.2	7.7	8.0
Nickel	ppm	< 0.2	0.2	< 0.2	< 0.2	0.5	0.2	< 0.2	0.2	< 0.2	0.3	0.2	< 0.2	< 0.2	0.2	0.3	0.4	--	0.5	0.6	--	< 1.5	--
Selenium	ppm	1.0	1.0	0.7	0.8	0.4	0.5	0.7	0.5	0.7	0.8	0.9	0.6	0.7	0.7	0.7	0.9	--	1.2	1.1	--	< 1.5	--
Mercury	ppm	< 0.1	< 0.1	< 0.1	< 0.1	< 0.22	< 0.2	< 0.17	< 0.1	< 0.1	< 0.2	< 0.2	< 0.22	< 0.02	< 0.02	< 0.02	< 0.2	--	< 0.19	< 0.19	--	< 0.02	--
Moisture	%	50.6	51.3	46.6	51.9	54.3	51.4	49.2	48.2	48.1	46	50.1	49.6	52.1	48.4	49.5	51.8	49.3	48.5	51.6	54.6	47.4	49.3
No. of Samples Composited		39	39	42	41	42	43	43	39	41	42	42	41	42	41	41	39	23	26	26	42	28	36

Parameter	Units	Concentration (dry basis) for Sample Weeks (collection dates) 1/14-1/20/02	1/14-1/20/02 Duplicate	1/21-1/27/02	1/28-2/3/02	2/4-2/10/02	2/11-2/17/02	2/11-2/17/02 Duplicate	2/18-2/24/02	2/25-3/3/02	3/4-3/10/02	3/4-3/10/02 Duplicate	3/11-3/17/02	3/18-3/24/02	3/25-3/31/02	3/25-3/31/02 Duplicate	11/25-12/1/02	12/9-12/15/02	12/23-12/29/02	12/23-12/29/02 Duplicate	1/6-1/12/03	1/20-1/26/03	2/3-2/9/03
HHV	Btu/lb	7,922	7,922	7,978	7,824	7,884	7,852	7,852	8,073	7,911	8,037	8,037	7,953	7,994	8,058	8,058	8,118	7,664	7,900	7,900	7,658	7,602	7,936
Chlorine	lb/MMBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0.049	0.058	0.048	--	0.070	0.051	0.084
Arsenic	lb/MMBtu	7.57E-05	7.57E-05	6.27E-05	6.39E-05	< 5.07E-05	3.82E-05	2.55E-05	2.48E-05	3.79E-05	4.98E-05	4.98E-05	< 3.77E-05	5.00E-05	3.72E-05	4.96E-05	4.93E-05	--	3.80E-05	6.33E-05	--	< 2.37E-04	--
Beryllium	lb/MMBtu	< 1.26E-05	< 1.26E-05	< 1.25E-05	< 1.28E-05	< 1.27E-05	< 1.27E-05	< 1.27E-05	< 1.24E-05	< 1.26E-05	< 1.24E-05	< 1.24E-05	< 1.26E-05	< 1.25E-05	< 1.24E-05	< 1.24E-05	< 1.23E-05	--	< 1.27E-05	< 1.27E-05	--	< 2.63E-05	--
Cadmium	lb/MMBtu	< 1.26E-05	< 1.26E-05	< 1.25E-05	< 1.28E-05	< 1.27E-05	< 1.27E-05	< 1.27E-05	< 1.24E-05	< 1.26E-05	< 1.24E-05	< 1.24E-05	< 1.26E-05	< 1.25E-05	< 1.24E-05	< 1.24E-05	< 1.23E-05	--	< 1.27E-05	< 1.27E-05	--	< 3.95E-05	--
Chromium	lb/MMBtu	5.05E-05	7.57E-05	2.51E-05	3.83E-05	7.61E-05	6.37E-05	5.09E-05	2.48E-05	3.79E-05	6.22E-05	9.95E-05	2.51E-05	3.75E-05	1.24E-05	2.48E-05	9.85E-05	--	6.33E-05	7.59E-05	--	7.89E-05	--
Lead	lb/MMBtu	3.79E-05	2.52E-05	< 3.76E-05	< 3.83E-05	< 5.07E-05	< 3.82E-05	< 3.82E-05	< 3.72E-05	2.53E-05	< 3.73E-05	3.73E-05	< 3.77E-05	< 3.75E-05	< 3.72E-05	< 3.72E-05	< 2.46E-05	--	5.06E-05	5.06E-05	--	< 2.37E-04	--
Manganese	lb/MMBtu	1.02E-03	9.47E-04	9.02E-04	1.14E-03	9.39E-04	1.04E-03	1.02E-03	7.68E-04	7.08E-04	9.95E-04	1.11E-03	7.29E-04	7.88E-04	1.35E-03	1.46E-03	1.17E-03	1.29E-03	9.87E-04	1.22E-03	1.33E-03	1.01E-03	1.01E-03
Nickel	lb/MMBtu	< 2.52E-05	2.52E-05	< 2.51E-05	< 2.56E-05	6.34E-05	2.55E-05	< 2.55E-05	2.48E-05	< 2.53E-05	3.73E-05	2.49E-05	< 2.51E-05	< 2.50E-05	2.48E-05	3.72E-05	4.93E-05	--	6.33E-05	7.59E-05	--	< 1.97E-04	--
Selenium	lb/MMBtu	1.26E-04	1.26E-04	8.77E-05	1.02E-04	5.07E-05	6.37E-05	8.91E-05	6.19E-05	8.85E-05	9.95E-05	1.12E-04	7.54E-05	8.76E-05	8.69E-05	8.69E-05	1.11E-04	--	1.52E-04	1.39E-04	--	< 1.97E-04	--
8-Metals Total		1.34E-03	1.29E-03	1.12E-03	1.39E-03	1.19E-03	1.27E-03	1.23E-03	9.35E-04	9.23E-04	1.28E-03	1.44E-03	8.93E-04	1.01E-03	1.55E-03	1.69E-03	1.50E-03	--	1.37E-03	1.63E-03	--	1.56E-03	--
8-Metals w/o Mn	lb/MMBtu	3.16E-04	3.41E-04	2.19E-04	2.49E-04	2.54E-04	2.23E-04	2.10E-04	1.67E-04	2.15E-04	2.80E-04	3.36E-04	1.63E-04	2.19E-04	1.92E-04	2.30E-04	3.33E-04		3.80E-04	4.18E-04		5.46E-04	
Mercury[b]	lb/MMBtu	< 1.26E-05	< 1.26E-05	< 1.25E-05	< 1.28E-05	< 2.79E-05	< 2.55E-05	< 2.17E-05	< 1.24E-05	< 1.26E-05	< 2.49E-05	< 2.49E-05	< 2.77E-05	< 2.50E-06	< 2.48E-06	< 2.48E-06	< 2.46E-05	--	< 2.41E-05	< 2.41E-05	--	< 2.63E-06	--
Manganese	lb/MMBtu	1.02E-03	9.47E-04	9.02E-04	1.14E-03	9.39E-04	1.04E-03	1.02E-03	7.68E-04	7.08E-04	9.95E-04	1.11E-03	7.29E-04	7.88E-04	1.35E-03	1.46E-03	1.17E-03	1.29E-03	9.87E-04	1.22E-03	1.33E-03	1.01E-03	1.01E-03

[a] For concentrations that are reported as below detection limit the minimum, maximum, average, and standard deviation were calculated by taking one-half of detection limit. Duplicate samples were not included in the calculations.

[b] Minimum, maximum, average, and standard deviation for mercury are based only on the individual samples with a lower detection limit.

[c] 90% confidence level calculated based on the following equation [40 CFR 63.7530(d)(2)]

P_{90} = mean + (SD * t); where,

P_{90} = 90% confidence level pollutant concentration (lb/MMBtu)

mean = average of fuel samples analyzed (lb/MMBtu)

SD = standard deviation of pollutant concentrations (lb/MMBtu)

t = t distribution critical value for 90% confidence probability (0.1) for n-1 degrees of freedom

n = number of samples

Table 3-3. Metals and Chlorine Analyses for Bagasse from U.S. Sugar Clewiston

Parameter	Units	2/17-2/23 03	3/3-3/9/03	3/3-3/9/03 Duplicate	3/17-3/23/03	3/31-4/6/03	3/31-4/6/03 Duplicate	Range [a] Min	Range [a] Max	Avg[a]	Parameter
Chlorine	ppm	558.86	681.00	--	605.89	719.74	--	376.65	719.74	536.80	Chlorine
Arsenic	ppm	0.5	--	--	0.3	--	--	0.15	0.90	0.39	Arsenic
Beryllium	ppm	< 0.2	--	--	< 0.2	--	--	< 0.05	< 0.10	< 0.06	Beryllium
Cadmium	ppm	< 0.4	--	--	< 0.4	--	--	< 0.05	< 0.20	< 0.08	Cadmium
Chromium	ppm	0.3	--	--	0.5	--	--	0.20	0.80	0.40	Chromium
Lead	ppm	0.3	--	--	0.3	--	--	0.10	0.90	0.24	Lead
Manganese	ppm	6.3	7.4	6.3	11	11.8	9	5.60	11.80	8.21	Manganese
Nickel	ppm	0.2	--	--	0.2	--	--	0.10	0.75	0.25	Nickel
Selenium	ppm	0.7	--	--	0.4	--	--	0.40	1.20	0.71	Selenium
Mercury	ppm	< 0.01	--	--	< 0.01	--	--	< 0.01	< 0.11	< 0.06	Mercury
Moisture	%	49.4	52.96	52.96	52.84	55.07	55.07	46	55.07	50.40	Moisture
No. of Samples Composited		34	38	38	26	32	32	--	--	--	

Parameter	Units	2/17-2/23 03	3/3-3/9/03	3/3-3/9/03 Duplicate	3/17-3/23/03	3/31-4/6/03	3/31-4/6/03 Duplicate	Range [a] Min	Range [a] Max	Avg[a]	Standard Deviation[a]	90% Confidence Level[c]	Parameter
HHV	Btu/lb	8,356	7,896	7,896	7,878	7,827	7,827	7,602	8,356	7,925	--	--	HHV
Chlorine	lb/MMBtu	0.067	0.086	--	0.077	0.092	--	0.048	0.086	0.065	0.015	0.093	Chlorine
											n =	10	
											t =	1.833	
Arsenic	lb/MMBtu	5.98E-05	--	--	3.81E-05	--	--	1.89E-05	1.18E-04	4.93E-05	--	--	Arsenic
Beryllium	lb/MMBtu	< 2.39E-05	--	--	< 2.54E-05	--	--	< 6.16E-06	< 1.32E-05	< 7.47E-06	--	--	Beryllium
Cadmium	lb/MMBtu	< 4.79E-05	--	--	< 5.08E-05	--	--	< 6.16E-06	< 2.54E-05	< 9.42E-06	--	--	Cadmium
Chromium	lb/MMBtu	3.59E-05	--	--	6.35E-05	--	--	1.24E-05	9.85E-05	4.96E-05	--	--	Chromium
Lead	lb/MMBtu	3.59E-05	--	--	3.81E-05	--	--	1.23E-05	1.18E-04	3.09E-05	--	--	Lead
Manganese	lb/MMBtu	7.54E-04	9.37E-04	7.98E-04	1.40E-03	1.51E-03	--	7.08E-04	1.40E-03	1.01E-03	--	--	Manganese
Nickel	lb/MMBtu	2.39E-05	--	--	2.54E-05	--	--	1.25E-05	9.87E-05	3.20E-05	--	--	Nickel
Selenium	lb/MMBtu	8.38E-05	--	--	5.08E-05	--	--	5.07E-05	1.52E-04	8.92E-05	--	--	Selenium
8-Metals Total		1.03E-03	--	--	1.65E-03	--	--	8.93E-04	1.65E-03	1.25E-03	2.46E-04	1.68E-03	8-Metals
											n =	16	
											t =	1.753	
8-Metals w/o Mn	lb/MMBtu	2.75E-04			2.54E-04			1.63E-04	5.46E-04	2.68E-04	9.44E-05	4.33E-04	
											n =	16	
											t =	1.753	
Mercury[b]	lb/MMBtu	< 1.20E-06	--	--	< 1.27E-06	--	--	< 5.98E-07	< 1.32E-06	< 1.01E-06	< 3.59E-07	< 1.77E-06	Mercury
											n =	5	
											t =	2.132	
Manganese	lb/MMBtu	7.54E-04	9.37E-04	7.98E-04	1.40E-03	1.51E-03	--	7.08E-04	1.40E-03	1.01E-03	2.13E-04	1.38E-03	Manganese
											n =	27	
											t =	1.706	

[a] For concentrations that are reported as below detection limit the minimum, maximum, average, and standard deviation were calculated by taking one-half of detection limit. Duplicate samples were not included in the calculations.

[b] Minimum, maximum, average, and standard deviation for mercury are based only on the individual samples with a lower detection limit.

[c] 90% confidence level calculated based on the following equation [40 CFR 63-7530(d)(2)].

P_{90} = mean + (SD * t), where:

P_{90} = 90% confidence level pollutant concentration (lb/MMBtu)

mean = average of fuel samples analyzed (lb/MMBtu)

SD = standard deviation of pollutant concentrations (lb/MMBtu)

t = t distribution critical value for 90% confidence probability (0.1) for n-1 degrees of freedom

n = number of samples

Table 3-4. Comparison of Historic U.S. Sugar Clewiston Mill Sampling and Analysis Procedures With Final Boiler MACT Rule

Rule Citation	Boiler MACT Rule Requirement	U.S. Sugar's Historic Procedures/Methods
	BAGASSE FUEL SAMPLING PROCEDURES	
63.7521(c)	**Must obtain at least 3 composite samples of each fuel type, following these procedures for a belt/screw feeder:**	Collected a composite sample during each shift during each day during each week of sampling.
	1. Stop belt and withdraw 6-inch wide sample from fuel cross-section of belt to obtain a minimum of 2 lbs. of sample. Collect all material in full cross-section. Transfer to clean plastic bag.	Grab samples were be taken at the point where bagasse exits the last mill in each milling tandem, as it transfers to the bagasse conveyor (there are two milling tandems). The locations of the samples spaned the the width of the bagasse stream. A total grab sample of approximately 1-quart was obtained (approx. 1 lbs) from each milling tandem. The two grab samples were then combined into one grab sample. The samples werer then collected and stored in a plastic bag and refrigerated until shipped to Golder for compositing.
	2. Each composite sample must consist of at least 3 samples collected at approximately equal intervals during testing period.	Each composite sample consisted of a weekly composite of all grab samples collected at approximately equal intervals during a sampling week.
63.7521(d)	**Prepare each composite sample according to these procedures:**	
	1. Thoroughly mix and pour entire composite sample over a clean plastic sheet.	Consistent with rule.
	2. Break sample pieces over 3 inches into smaller sizes.	Not necessary since bagasse fuel has already been ground in the sugar mill grinding mills.
	3. Make a pie shape with entire composite sample and subdivide it into 4 equal parts.	Consistent with rule.
	4. Separate one of 1/4 samples as first subset.	Consistent with rule.
	5. If subset is too large for grinding, repeat step #3.	Not applicable.
	6. Grind sample in a mill.	Samples were not ground since this is not necessary due to small particle size of bagasse fuel. Lab cut the samples prior to digestion as necessary.
	7. Use step #3 to obtain a 1/4 subsample for analysis.	Consistent with rule.
	8. If 1/4 sample is too large, subdivide it further using same procedure.	Consistent with rule.
63.7521(e)	**Determine pollutant (Hg, HCl, and/or TSM) concentrations in fuel in lb/MMBtu of each composite sample.**	Proximate, ultimate, heat content, metals, and chlorine analyses were performed. All pollutants were calculated in lb/MMBtu based on heat content.
	BAGASSE FUEL ANALYTICAL PROCEDURES	
Table 6	1. Collect fuel samples--63.7521(c) or ASTM D6323-98 (2003) or equivalent	see above for differences in procedure
	2. Composite fuel samples--63.7521(d) or equivalent	see above for differences in procedure
	3. Prepare composited fuel samples--SW846-3050B or ASTM D5198-92 (2003) or equivalent	SW846-3050B
	4. Determine heat content of fuel type--ASTM E711-87 (1996) or equivalent	ASTM D3286 (equivalent to E711-87)
	5. Determine moisture content of fuel type--ASTM D3173-02 or ASTM E871-82 (1998) or equivalent	ASTM D3173-02
	6. Measure pollutant concentration in fuel sample:	
	--Mercury--SW-846-7471A	SW846-7471A
	--Total selected metals--ASTM E885-88 (1996)	SW846-6010 (both SW846-6010 and ASTM E885-88 are ICP methods, but may use different equipment. 6010 is the industry standard because it yields faster results and has lower detection limits)
	--Chlorine--SW-846-9250 or ASTM E776-87 (1996) or equivalent	ASTM D4208 (both D4208 and E776-87 are oxygen bomb methods, although methods may differ somewhat)
	7. Convert concentrations into units of lbs pollutant/MMBtu of heat content	Converted using concentrations in ppm and heat content.

ATTACHMENT C

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

ATTACHMENT C
NATIONAL EMISSION STANDARDS
U.S. SUGAR BOILER NO. 8

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	**Sec. 63.7480 What is the purpose of this subpart?**	
Y	This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.	
Y	**Sec. 63.7485 Am I subject to this subpart?**	
Y	You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 63.2 or Sec. 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in Sec. 63.7491.	Clewiston is a major source of HAPs, and Boiler No. 8 has a heat input capacity of greater than 10 MMBtu/hr.
Y	**Sec. 63.7490 What is the affected source of this subpart?**	
Y	(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.	
N	(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in Sec. 63.7575.	
Y	(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in Sec. 63.7575.	Construction of Boiler No. 8 began after Jan. 13, 2003.
Y	(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.	Construction of Boiler No. 8 began after Jan. 13, 2003.
N	(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in Sec. 63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.	
N	(d) A boiler or process heater is existing if it is not new or reconstructed.	
N	**Sec. 63.7491 Are any boilers or process heaters not subject to this subpart?**	
N	The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.	
N	(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBB, subpart Cb or subpart Eb.	
N	(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.	
N	(c) An electric utility steam generating unit that is a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity, and supplies more than one-third of its potential electric output capacity, and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.	
N	(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE (e.g., hazardous waste boilers).	
N	(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCC or subpart DDDD.	
N	(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.	
N	(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.	
N	(h) A hot water heater as defined in this subpart.	
N	(i) A refining kettle covered by 40 CFR part 63, subpart X.	
N	(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.	
N	(k) Blast furnace stoves as described in the EPA document, entitled "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants--Background Information for Proposed Standards," (EPA-453/R-01-005).	

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
N	(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.	
N	(m) Any boiler and process heater specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).	
N	(n) Temporary boilers as defined in this subpart.	
N	(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.	
Y	**Sec. 63.7495 When do I have to comply with this subpart?**	
Y	(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.	Boiler No. 8 wil comply upon startup.
N	(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.	
N	(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.	
N	(1) Any new or reconstructed boiler or process heater at the existing facility must be in compliance with this subpart upon startup.	
N	(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.	
Y	(d) You must meet the notification requirements in Sec. 63.7545 according to the schedule in Sec. 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.	
Y	**Emission Limits and Work Practice Standards**	
Y	**Sec. 63.7499 What are the subcategories of boilers and process heaters?**	
Y	The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in Sec. 63.7575.	Boiler No. 8 is in the large solid fuel category.
Y	**Sec. 63.7500 What emission limits, work practice standards, and operating limits must I meet?**	
Y	(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.	
Y	(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under Sec. 63.7507.	Boiler No. 8 must meet MACT standards for new sources.
Y	Table 1: PM - 0.025 lb/MMBtu, or TSM - 0.0003 lb/MMBtu*	New source standard.
Y	HCl - 0.02 lb/MMBtu*	New source standard.
Y	Hg - 3E-06 lb/MMBtu	New source standard.
Y	CO - 400 ppmvd @ 7% O2, 30-day rolling average	New source standard.
Y	* May opt to demonstrate compliance with health-based alternative for HCl and TSM.	New source standard.
Y	(2) You must meet each operating limit in Tables 2 through 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under Sec. 63.8(f).	Boiler No. 8 uses the combination of wet scrubber and ESP control devices.
Y	Tables 2, 3 and 4: PM, TSM, Hg - if using ESP control with additional wet control system: maintain minimum voltage and secondary current or total power input to the ESP at or above compliance test values.	Boiler No. 8 will use ESP control with additional wet control system: maintain minimum voltage and secondary current or total power input to the ESP at or above compliance test values.

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	HCl - maintain minimum scrubber effluent pH, pressure drop and liquid flow rate at or above compliance test values.	Boiler No. 8 will maintain minimum scrubber effluent pH, pressure drop and liquid flow rate at or above compliance test values.
Y	Fuel Analysis - maintain fuel type such that Hg, TSM and HCl emission rates are less than applicable limits.	Boiler No. 8 will use Fuel Analysis and maintain fuel type such that Hg emission rate is less than applicable limit.
Y	(b) As provided in Sec. 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.	Boiler No. 8 is requesting some altenatives to test procedures.
Y	**General Compliance Requirements**	
Y	**Sec. 63.7505 What are my general requirements for complying with this subpart?**	
Y	(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.	
Y	(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in Sec. 63.6(e)(1)(i).	
Y	(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to Sec. 63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.	Boiler No. 8 will demonstrate compliance with Hg limits through fuel analysis.
Y	(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under Sec. 63.8(f).	Boiler No. 8 will demonstrate compliance with TSM and HCl limits through fuel analysis.
Y	(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan at least 60 days before your initial performance evaluation of your CMS.	A site-specific monitoring is being submitted.
Y	(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);	A site-specific monitoring is being submitted.
Y	(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and	A site-specific monitoring is being submitted.
Y	(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).	A site-specific monitoring is being submitted.
Y	(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.	A site-specific monitoring is being submitted.
Y	(i) Ongoing operation and maintenance procedures in accordance with the general requirements of Sec. 63.8(c)(1), (c)(3), and (c)(4)(ii);	A site-specific monitoring is being submitted.
Y	(ii) Ongoing data quality assurance procedures in accordance with the general requirements of Sec. 63.8(d); and	A site-specific monitoring is being submitted.
Y	(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of Sec. 63.10(c), (e)(1), and (e)(2)(i).	A site-specific monitoring is being submitted.
Y	(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.	A site-specific monitoring is being submitted.
Y	(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.	A site-specific monitoring is being submitted.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(e) If you have an applicable emission limit or work practice standard, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in Sec. 63.6(e)(3).	A SSM Plan will be developed prior to startup of Boiler No. 8.
Y	**Sec. 63.7506 Do any boilers or process heaters have limited requirements?**	
N	(a) New or reconstructed boilers and process heaters in the large liquid fuel subcategory or the limited use liquid fuel subcategory that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and maintain operating limits to demonstrate continuous compliance with the emission limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section and meet the CO work practice standard in Table 1 to this subpart.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in Sec. 63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in Sec. 63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in Sec. 63.9(b) (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(1) Existing large and limited use gaseous fuel units.	Boiler No. 8 is not in the gaseous fuel subcategory.
N	(2) Existing large and limited use liquid fuel units.	Boiler No. 8 is not in the liquid fuel subcategory.
N	(3) New or reconstructed small liquid fuel units that burn only gaseous fuels or distillate oil. New or reconstructed small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in Sec. 63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(1) Existing small solid fuel boilers and process heaters.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(2) Existing small liquid fuel boilers and process heaters.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(3) Existing small gaseous fuel boilers and process heaters.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	(4) New or reconstructed small gaseous fuel units.	Boiler No. 8 is not in the gaseous fuel or liquid fuel subcategories.
N	**Sec. 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?**	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(a) As an alternative to the requirement for large solid fuel boilers located at a single facility to demonstrate compliance with the HCl emission limit in Table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.	
N	(b) In lieu of complying with the TSM emission standards in Table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM emission standards in Table 1 based on the sum of emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions) under the procedures prescribed in appendix A to this subpart.	
Y	**Testing, Fuel Analyses, and Initial Compliance Requirements**	
Y	**Sec. 63.7510 What are my initial compliance requirements and by what date must I conduct them?**	
Y	(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to Sec. 63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to Sec. 63.7521 and Table 6 to this subpart, establishing operating limits according to Sec. 63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to Sec. 63.7525.	Boiler No. 8 will demonstrate compliance through a combination of methods.
Y	(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to Sec. 63.7521 and Table 6 to this subpart and establish operating limits according to Sec. 63.7530 and Table 8 to this subpart.	Boiler No. 8 will demonstrate compliance with the Hg limit through fuel analysis, …..
Y	(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to Sec. 63.7525(a).	Boiler No. 8 will be subject to the CO work practice standard.
N	(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in Sec. 63.7495 and according to the applicable provisions in Sec. 63.7(a)(2) as cited in Table 10 to this subpart.	Boiler No. 8 is not an existing affected source.
Y	(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and November 12, 2004, you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after November 12, 2004 or within 180 days after startup of the source, whichever is later, according to Sec. 63.7(a)(2)(ix).	Boiler No. 8 will demonstrate compliance with the promulgated emisison limits and work practice standards within 180 days of startup.
N	(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and November 12, 2004, and you chose to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after November 12, 2004 or within 3 years after startup of the affected source, whichever is later.	Boiler No. 8 will demonstrate compliance with the promulgated emisison limits and work practice standards within 180 days of startup.
N	(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.	Boiler No. 8 commenced construction prior to November 12, 2004.
Y	**Sec. 63.7515 When must I conduct subsequent performance tests or fuel analyses?**	
Y	(a) You must conduct all applicable performance tests according to Sec. 63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.	

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.	
Y	(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.	
Y	(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.	
N	(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.	Boiler No. 8 is not in any of the limited use subcategories, and has a heat input capacity less than 100 MMBtu/hr.
Y	(f) You must conduct a fuel analysis according to Sec. 63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in Sec. 63.7540.	
Y	(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to Sec. 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in Sec. 63.7550.	
Y	**Sec. 63.7520 What performance tests and procedures must I use?**	
Y	(a) You must conduct all performance tests according to Sec. 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in Sec. 63.7(c) if you elect to demonstrate compliance through performance testing.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.	
N	(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to Sec. 63.7506(a).	Boiler No. 8 is not in one of the liquid fuel subcategories.
Y	(d) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.	
Y	(f) You must conduct three separate test runs for each performance test required in this section, as specified in Sec. 63.7(e)(3). Each test run must last at least 1 hour.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	(g) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.	Boiler No. 8 will demonstrate compliance with the PM and HCl limits through performance testing.
Y	**Sec. 63.7521 What fuel analyses and procedures must I use?**	
Y	(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.	Boiler No. 8 will be required to conduct fuel analysis for TSM, Hg and HCl.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.	
Y	(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.	
Y	(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.	
Y	(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.	
Y	(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
N	(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.	Boiler No. 8 will not rely upon a fuel analysis from a fuel supplier.
Y	(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.	Boiler No. 8 will submit a site-specific fuel analysis plan for TSM, Hg and HCl.
Y	(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.	
Y	(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.	Boiler No. 8 will submit a request for an alternative test procedure since it is not practical to stop the belt feeder.
Y	(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.	
Y	(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.	
Y	(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.	
Y	(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.	
Y	(iii) Transfer all samples to a clean plastic bag for further processing.	
Y	(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.	
Y	(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.	
Y	(2) Break sample pieces larger than 3 inches into smaller sizes.	
Y	(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.	
Y	(4) Separate one of the quarter samples as the first subset.	
Y	(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.	

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(6) Grind the sample in a mill.	
Y	(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.	
Y	(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.	
N	**Sec. 63.7522 Can I use emission averaging to comply with this subpart?**	Boiler No. 8 is not eligible for the emissions averaging option.
N	(a) As an alternative to meeting the requirements of Sec. 63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.	
N	(b) For each existing large solid fuel boiler in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on November 12, 2004 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on November 12, 2004.	
N	(c) You may average particulate matter or TSM, HCl, and mercury emissions from existing large solid fuel boilers to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (d), (e), and (f) of this section.	
N	(d) The weighted average emissions from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in Sec. 63.7495.	
N	(e) You must demonstrate initial compliance according to paragraphs (e)(1) or (2) of this section.	
N	(1) You must use Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.	
N	Where:	
N	AveWeighted = Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Hm = Maximum rated heat input capacity of boiler, i, in units of million Btu per hour.	
N	n = Number of large solid fuel boilers participating in the emissions averaging option.	
N	(2) If you are not capable of monitoring heat input, you can use Equation 2 of this section as an alternative to using equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.	
N	Where:	
N	AveWeighted = Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Sm = Maximum steam generation by boiler, i, in units of pounds.	
N	Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.	
N	(f) You must demonstrate continuous compliance on a 12-month rolling average basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) and (2). The first 12-month rolling-average period begins on the compliance date specified in Sec. 63.7495.	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(1) For each calendar month, you must use Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual heat capacity for each existing large solid fuel boiler participating in the emissions averaging option.	
N	Where:	
N	AveWeighted Emissions = 12-month rolling average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate, calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Hb = The average heat input for each calendar month of boiler, i, in units of million Btu.	
N	n = Number of large solid fuel boilers participating in the emissions averaging option.	
N	(2) If you are not capable of monitoring heat input, you can use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.	
N	Where:	
N	AveWeighted Emissions = 12-month rolling average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Er = Emission rate, calculated during the most recent compliance test (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in Sec. 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.	
N	Sa = Actual steam generation for each calender month by boiler, i, in units of pounds.	
N	Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.	
N	(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory authority for review and approval according to the following procedures and requirements in paragraphs (g)(1) through (4).	
N	(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.	
N	(2) You must include the information contained in paragraphs g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:	
N	(i) The identification of all existing large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;	
N	(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;	
N	(iii) The specific control technology or pollution prevention measure to be used for each emission source in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple sources, the owner or operator must identify each source;	
N	(iv) The test plan for the measurement of particulate matter (or TSM), HCl, or mercury emissions in accordance with the requirements in Sec. 63.7520;	
N	(v) The operating parameters to be monitored for each control system or device and a description of how the operating limits will be determined;	
N	(vi) If you request to monitor an alternative operating parameter pursuant to Sec. 63.7525, you must also include:	
N	(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and	
N	(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.	
N	(3) Upon receipt, the regulatory authority shall review and approve or disapprove the plan according to the following criteria:	
N	(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and	
N	(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.	
N	(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:	
N	(i) Any averaging between emissions of differing pollutants or between differing sources; or	
N	(ii) The inclusion of any emission source other than an existing large solid fuel boiler.	
Y	**Sec. 63.7525 What are my monitoring, installation, operation, and maintenance requirements?**	
Y	(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in Sec. 63.7495.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR, part 60, appendix B, and according to the site-specific monitoring plan developed according to Sec. 63.7505(d).	Boiler No. 8 will be subject to the CO work practice standard.
Y	(2) You must conduct a performance evaluation of each CEMS according to the requirements in Sec. 63.8 and according to PS 4A of 40 CFR part 60, appendix B.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(4) The CEMS data must be reduced as specified in Sec. 63.8(g)(2).	Boiler No. 8 will be subject to the CO work practice standard.
Y	(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.	Boiler No. 8 will be subject to the CO work practice standard.
Y	(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.	Boiler No. 8 will be subject to the CO work practice standard.
N	(b) If you have an applicable opacity operating limit, you must install, operate, certify, and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of this section by the compliance date specified in Sec. 63.7495.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(2) You must conduct a performance evaluation of each COMS according to the requirements in Sec. 63.8 and according to PS 1 of 40 CFR part 60, appendix B.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(3) As specified in Sec. 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(4) The COMS data must be reduced as specified in Sec. 63.8(g)(2).	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in Sec. 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of Sec. 63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
N	(7) You must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.	Boiler No. 8 will not be subject to an opacity standard since it uses a wet scrubber in combination with an ESP.
Y	(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in Sec. 63.7495.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(5) Record the results of each inspection, calibration, and validation check.	Boiler No. 8 will have CMS for the wet scrubber and the ESP.
Y	(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(4) Conduct a flow sensor calibration check at least semiannually.	Boiler No. 8 will have a liquid flow measuring device on the wet scrubber.
Y	(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(4) Check pressure tap pluggage daily.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.	Boiler No. 8 will have a pressure measuring device on the wet scrubber.
Y	(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(2) Ensure the sample is properly mixed and representative of the fluid to be measured.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.	Boiler No. 8 will have a pH measuring device on the wet scrubber.
Y	(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.	Boiler No. 8 will be required to measure ESP operating parameters.
N	(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.	Boiler No. 8 will not utilize sorbent injection.
N	(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.	Boiler No. 8 will not utilize sorbent injection.
N	(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.	Boiler No. 8 will not utilize sorbent injection.

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.	Boiler No. 8 will not utilize sorbent injection.
N	(i) If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of this section.	Boiler No. 8 will not use a fabric filter.
N	(4) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.	Boiler No. 8 will not use a fabric filter.
N	(5) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA 454/R-98-015, September 1997.	Boiler No. 8 will not use a fabric filter.
N	(6) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.	Boiler No. 8 will not use a fabric filter.
N	(7) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.	Boiler No. 8 will not use a fabric filter.
N	(8) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.	Boiler No. 8 will not use a fabric filter.
N	(9) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.	Boiler No. 8 will not use a fabric filter.
N	(10) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.	Boiler No. 8 will not use a fabric filter.
N	(11) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.	Boiler No. 8 will not use a fabric filter.
Y	**Sec. 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?**	
Y	(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to Sec. 63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to Sec. 63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.	Boiler No. 8 will conduct initial performance tests for PM and HCl and fuel analysis for Hg.
N	(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to Sec. 63.7506(a).	Boiler No. 8 is not in one of the liquid fuel subcategories.
Y	(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in Sec. 63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to Sec. 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.	Boiler No. 8 will conduct initial performance tests for PM, PM and HCl and fuel analysis for Hg.
Y	(1) You must establish the maximum chlorine fuel input (Cinput) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.	Boiler No. 8 will conduct initial performance tests and fuel analysis for HCl.
Y	(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.	
Y	(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).	
Y	(iii) You must establish a maximum chlorine input level using Equation 5 of this section.	
Y	Where:	
Y	Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.	

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
Y	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
Y	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.	
N	(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level (TSMinput) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.	Boiler No. 8 will not choose to comply with the alternative TSM limit.
N	(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.	
N	(ii) During the performance testing for TSM, you must determine the fraction of total heat input from each fuel burned (Qi) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned (Mi).	
N	(iii) You must establish a baseline TSM input level using Equation 6 of this section.	
N	Where:	
N	TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.	
N	Mi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
N	Qi = Fraction of total heat input from based fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
N	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.	
N	(3) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.	Boiler No. 8 will comply with the Hg limit through fuel analysis.
N	(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.	
N	(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).	
N	(iii) You must establish a maximum mercury input level using Equation 7 of this section.	
N	Where:	
N	Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.	
N	HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
N	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
N	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.	

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.	
Y	(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in Sec. 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.	Boiler No. 8 will utilize a wet scrubber.
Y	(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in Sec. 63.7575, as your operating limits during the three-run performance test.	Boiler No. 8 will utilize an ESP.
N	(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in Sec. 63.7575, as your operating limit during the three-run performance test.	Boiler No. 8 will not utilize a dry scrubber.
N	(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in Sec. 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.	Boiler No. 8 will not utilize a fabric filter.
Y	(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to Sec. 63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.	Boiler No. 8 will comply with the Hg limit through fuel analysis.
Y	(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.	The worst case fuel will be bagasse.
Y	(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.	
Y	Where:	
Y	P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.	
Y	mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
Y	SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.	
Y	t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.	
Y	(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.	Boiler No. 8 will comply with the HCl limit through fuel analysis and a site-specific risk analysis.
Y	Where:	
Y	HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.	
Y	Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.	
Y	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
Y	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.	
Y	1.028 = Molecular weight ratio of HCl to chlorine.	

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Applicable?	What This Subpart Covers	Applicability Rationale
N	(4) To demonstrate compliance with the applicable emission limit for TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.	Boiler No. 8 will not choose to comply with the alternative TSM limit.
N	Where:	
N	TSM = TSM emission rate from the boiler or process heater in units of pounds per million Btu.	
N	Mi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.	
N	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
N	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.	
Y	(5) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must be less than the applicable emission limit for mercury.	Boiler No. 8 will comply with the Hg limit hrough fuel analysis.
Y	Where:	
Y	Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.	
Y	HGi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.	
Y	Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.	
Y	n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.	
Y	(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in Sec. 63.7545(e).	
Y	**Continuous Compliance Requirements**	
Y	**Sec. 63.7535 How do I monitor and collect data to demonstrate continuous compliance?**	
Y	(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by Sec. 63.7505(d).	
Y	(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.	
Y	(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.	Boiler No. 8 will have a CEMS for CO.
Y	**Sec. 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?**	
Y	(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.	
Y	(1) Following the date on which the initial performance test is completed or is required to be completed under Sec. 63.7 and 63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.	

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Y	(2) You must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).	
N	(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of Sec. 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.	Boiler No. 8 will demonstrate compliance with HCl by performance testing.
N	(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to Sec. 63.7521(b).	
N	(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.	
N	(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of Sec. 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.	
Y	(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel type or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 5 of Sec. 63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of Sec. 63.7530 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Sec. 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in Sec. 63.7530(c).	
N	(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 10 of Sec. 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.	Boiler No. 8 will not choose to comply with the alternative TSM limit.
N	(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to Sec. 63.7521(b).	
N	(ii) You must determine the new mixture of fuels that will have the highest content of TSM.	
N	(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 10 of Sec. 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.	
N	(6) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 6 of Sec. 63.7530. If the results of recalculating the maximum total selected metals input using Equation 6 of Sec. 63.7530 are higher than the maximum TSM input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Sec. 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in Sec. 63.7530(c).	Boiler No. 8 will not choose to comply with the alternative TSM limit.
Y	(7) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of Sec. 63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.	Boiler No. 8 will comply with the Hg limit through fuel analysis.
Y	(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to Sec. 63.7521(b).	
Y	(ii) You must determine the new mixture of fuels that will have the highest content of mercury.	
Y	(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of Sec. 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.	

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N	(8) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 7 of Sec. 63.7530. If the results of recalculating the maximum mercury input using Equation 7 of Sec. 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Sec. 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in Sec. 63.7530(c).	Boiler No. 8 will comply with the Hg limit through fuel analysis.
N	(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions according to your SSMP, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.	Boiler No. 8 will not utilize a fabric filter.
Y	(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to Sec. 63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.	Boiler No. 8 will have a CEMS for CO.
Y	(i) You must continuously monitor carbon monoxide according to Sec. 63.7525(a) and 63.7535.	
Y	(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.	
Y	(iii) Keep records of carbon monoxide levels according to Sec. 63.7555(b).	
Y	(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in Sec. 63.7550.	
Y	(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in Sec. 63.7505(e).	
Y	(d) Consistent with Sec. Sec. 63.6(e)and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in Sec. 63.6(e).	
N	**Sec. 63.7541 How do I demonstrate continuous compliance under the emission averaging provision?**	Boiler No. 8 is not eligible for the emissions averaging provision.
N	(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.	
N	(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in Sec. 63.7522(f) and (g);	
N	(2) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system, maintain opacity at or below the applicable limit;	
N	(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and	
N	(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.	

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N	(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (4) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.	
Y	**Notification, Reports, and Records**	
Y	**Sec. 63.7545 What notifications must I submit and when?**	
Y	(a) You must submit all of the notifications in Sec. Sec. 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.	
N	(b) As specified in Sec. 63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.	Boiler No. 8 will startup after Nov. 12, 2004.
N	(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by Sec. 63.9(b)(2).	
N	(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by Sec. 63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.	
Y	(c) As specified in Sec. 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.	Boiler No. 8 must submit the initial notification within 15 days of startup.
Y	(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.	Boiler No. 8 will submit the Notification of Intent at least 30 days prior to beginning testing.
Y	(e) If you are required to conduct an initial compliance demonstration as specified in Sec. 63.7530(a), you must submit a Notification of Compliance Status according to Sec. 63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to Sec. 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.	The Notification of Compliance Status will be submitted within 60 days following completion of the performance tests.
Y	(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.	
Y	(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.	
Y	(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.	
Y	(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.	
Y	(5) Identification of whether you plan to demonstrate compliance by emissions averaging.	
Y	(6) A signed certification that you have met all applicable emission limits and work practice standards.	
Y	(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.	
Y	(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.	

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Y	(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.	
Y	**Sec. 63.7550 What reports must I submit and when?**	
Y	(a) You must submit each report in Table 9 to this subpart that applies to you.	
Y	(b) Unless the EPA Administrator has approved a different schedule for submission of reports under Sec. 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.	
Y	(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in Sec. 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in Sec. 63.7495.	
Y	(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in Sec. 63.7495.	
Y	(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.	
Y	(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.	
Y	(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.	
Y	(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.	
Y	(1) Company name and address.	
Y	(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.	
Y	(3) Date of report and beginning and ending dates of the reporting period.	
Y	(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.	
Y	(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.	
Y	(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of Sec. 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of Sec. 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of Sec. 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).	

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Y	(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of Sec. 63.7530, the maximum TSM input operating limit using Equation 6 of Sec. 63.7530, or the maximum mercury input operating limit using Equation 7 of Sec. 63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.	
Y	(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.	
Y	(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in Sec. 63.10(d)(5)(i).	
Y	(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.	
Y	(11) If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in Sec. 63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period.	
Y	(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.	
Y	(1) The total operating time of each affected source during the reporting period.	
Y	(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.	
Y	(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.	
Y	(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.	
Y	(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c) (1) through (10) of this section and the information required in paragraphs (e) (1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in Sec. 63.7505(d).	
Y	(1) The date and time that each malfunction started and stopped and description of the nature of the deviation (i.e., what you deviated from).	
Y	(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.	
Y	(3) The date, time, and duration that each CMS was out of control, including the information in Sec. 63.8(c)(8).	
Y	(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.	
Y	(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.	
Y	(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.	
Y	(7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.	
Y	(8) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.	
Y	(9) A brief description of the source for which there was a deviation.	
Y	(10) A brief description of each CMS for which there was a deviation.	
Y	(11) The date of the latest CMS certification or audit for the system for which there was a deviation.	

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Y	(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.	
Y	(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.	
N	(g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in Sec. 63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.	Boiler No. 8 is not in the new gaseous fuel category.
N	(1) Company name and address.	
N	(2) Identification of the affected unit.	
N	(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.	
N	(4) Type of alternative fuel that you intend to use.	
N	(5) Dates when the alternative fuel use is expected to begin and end.	
Y	**Sec. 63.7555 What records must I keep?**	
Y	(a) You must keep records according to paragraphs (a)(1) through (3) of this section.	
Y	(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in Sec. 63.10(b)(2)(xiv).	
Y	(2) The records in Sec. 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.	
Y	(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in Sec. 63.10(b)(2)(viii).	
Y	(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.	
Y	(1) Records described in Sec. 63.10(b)(2) (vi) through (xi).	
Y	(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in Sec. 63.6(h)(7)(i) and (ii).	
Y	(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in Sec. 63.8(d)(3).	
Y	(4) Request for alternatives to relative accuracy test for CEMS as required in Sec. 63.8(f)(6)(i).	
Y	(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.	
Y	(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.	
Y	(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.	
Y	(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.	
Y	(2) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.	

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Applicable?	What This Subpart Covers	Applicability Rationale
Y	(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of Sec. 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 9 of Sec. 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.	
N	(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 6 of Sec. 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 10 of Sec. 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.	Boiler No. 8 is not choosing to comply with the alternative TSM limit.
Y	(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of Sec. 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of Sec. 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.	
N	(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.	Boiler No. 8 does not have a 10 percent capacity factor limitation.
N	(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.	
N	(2) Fuel use records for the days the boiler or process heater was operating.	
Y	**Sec. 63.7560 In what form and how long must I keep my records?**	
Y	(a) Your records must be in a form suitable and readily available for expeditious review, according to Sec. 63.10(b)(1).	
Y	(b) As specified in Sec. 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.	
Y	(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to Sec. 63.10(b)(1). You can keep the records off site for the remaining 3 years.	
Y	**Other Requirements and Information**	
Y	**Sec. 63.7565 What parts of the General Provisions apply to me?**	
Y	Table 10 to this subpart shows which parts of the General Provisions in Sec. Sec. 63.1 through 63.15 apply to you.	
Y	**Sec. 63.7570 Who implements and enforces this subpart?**	
Y	(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.	
Y	(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.	
Y	(1) Approval of alternatives to the non-opacity emission limits and work practice standards in Sec. 63.7500(a) and (b) under Sec. 63.6(g).	

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Y	(2) Approval of alternative opacity emission limits in Sec. 63.7500(a) under Sec. 63.6(h)(9).	
Y	(3) Approval of major change to test methods in Table 5 to this subpart under Sec. 63.7(e)(2)(ii) and (f) and as defined in Sec. 63.90.	
Y	(4) Approval of major change to monitoring under Sec. 63.8(f) and as defined in Sec. 63.90.	
Y	(5) Approval of major change to recordkeeping and reporting under Sec. 63.10(f) and as defined in Sec. 63.90.	
Y	**Sec. 63.7575 What definitions apply to this subpart?**	
Y	Terms used in this subpart are defined in the CAA, in Sec. 63.2 (the General Provisions), and in this section as follows:	
Y	**Annual capacity factor** means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.	
Y	**Bag leak detection system** means an instrument that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.	
Y	**Biomass fuel** means unadulterated wood as defined in this subpart, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.	
Y	**Blast furnace gas** fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.	
Y	**Boiler** means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.	
Y	**Coal** means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388-991 .\1\, ``Standard Specification for Classification of Coals by Rank \1\" (incorporated by reference, see Sec. 63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.	
Y	**Coal refuse** means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.	
Y	**Commercial/institutional boiler** means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.	
Y	**Construction/demolition material** means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.	
Y	**Deviation.** (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:	
Y	(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;	
Y	(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or	
Y	(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.	
Y	(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.	
Y	**Distillate oil** means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1" (incorporated by reference, see Sec. 63.14(b)).	

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Y	**Dry scrubber** means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.	
Y	**Electric utility steam generating unit** means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.	
Y	**Electrostatic precipitator** means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.	
Y	**Fabric filter** means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.	
Y	**Federally enforceable** means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.	
Y	**Firetube boiler** means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.	
Y	**Fossil fuel** means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.	
Y	**Fuel type** means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.	
Y	**Gaseous fuel** includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.	
Y	**Heat input** means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.	
Y	**Hot water heater** means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210[deg]F (99[deg]C).	
Y	**Industrial boiler** means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.	
Y	**Large gaseous fuel subcategory** includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.	
Y	**Large liquid fuel subcategory** includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.	
Y	**Large solid fuel subcategory** includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.	
Y	**Limited use gaseous fuel subcategory** includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.	

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Y	**Limited use liquid fuel subcategory** includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.	
Y	**Limited use solid fuel subcategory** includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.	
Y	**Liquid fossil fuel** means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.	
Y	**Liquid fuel** includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.	
Y	**Minimum pressure drop** means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.	
Y	**Minimum scrubber effluent pH** means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.	
Y	**Minimum scrubber flow rate** means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.	
Y	**Minimum sorbent flow rate** means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.	
Y	**Minimum voltage or amperage** means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.	
Y	**Natural gas** means:	
Y	(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or	
Y	(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, "Standard Specification for Liquid Petroleum Gases" (incorporated by reference, see Sec. 63.14(b)).	
Y	**Opacity** means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.	
Y	**Particulate matter** means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.	
Y	**Period of natural gas curtailment or supply interruption** means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.	
Y	**Process heater** means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.	
Y	**Residual oil** means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1" (incorporated by reference, see Sec. 63.14(b)).	
Y	**Responsible official** means responsible official as defined in 40 CFR 70.2.	
Y	**Small gaseous fuel subcategory** includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.	

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Applicable?	What This Subpart Covers	Applicability Rationale
Y	**Small liquid fuel subcategory** includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.	
Y	**Small solid fuel subcategory** includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.	
Y	**Solid fuel** includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.	
Y	**Temporary boiler** means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.	
Y	**Total selected metals** means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.	
Y	**Unadulterated wood** means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.	
Y	**Waste heat boiler** means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.	
Y	**Watertube boiler** means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.	
Y	**Wet scrubber** means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.	
Y	**Work practice standard** means any design, equipment, work practice, or operational standard, or combination thereof that is promulgated pursuant to section 112(h) of the CAA.	

ATTACHMENT D

SITE-SPECIFIC MONITORING PLAN

SECTION PAGE

APPENDICES

Appendix A Performance and Equipment Specifications for Custom Instrumentation Services Corporation (CISCO)

Appendix B Data Acquisition and Handling System (DAHS) Specifications by CISCO

1.0 INTRODUCTION

United States Sugar Corporation (U.S. Sugar) operates a sugar mill and sugar refinery located in Clewiston, Hendry County, Florida. The mill receives sugarcane by train from nearby cane fields and processes it into raw sugar. The facility is currently permitted under Title V operating permit no. 0510003-017-AV, issued October 18, 2004.

Boiler No. 8 at the Clewiston Mill will be regulated, upon startup, under Title 40 of the Code of Federal Regulations, Part 63 (40 CFR 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers and Process Heaters. Subpart DDDDD (Boiler MACT) regulates emissions of mercury (Hg), solid hazardous air pollutant (HAP) metals, inorganic HAPs, and organic HAPs. The regulation of solid HAP metals emissions is through a surrogate particulate matter (PM) emission standard, or alternatively a total selected metals (TSM) standard. The regulation of inorganic HAPs is through a surrogate hydrogen chloride (HCl emission standard.

The Boiler MACT regulates organic HAPs through a surrogate carbon monoxide (CO) work practice standard for new units only, which requires a continuous emission monitoring system (CEMS) to measure CO concentrations in the flue gas stream. The CO work practice standard for all fuels is 400 parts per million by volume, dry basis, corrected to 7 percent oxygen (ppmvd @ 7 percent O_2).

The Boiler MACT also sets operating limits for add-on control devices. Boiler No. 8 will employ a wet sand separator and an electrostatic precipitator (ESP) for control of PM emissions. For Boiler No. 8, the Boiler MACT requires the following parameters to be monitored continuously:

Work Practice Standard	Continuous Monitoring System (CMS) Parameter
CO	CO ppmvd @ 7% O_2: 30-day rolling average
Add-on Control Device	
Wet Scrubber	Liquid Flow, Pressure Drop, and pH
ESP	Voltage and Secondary Current, or Total Power Input

The Boiler MACT compliance date for Boiler No. 8 is upon startup. According to the Boiler MACT, for each continuous monitoring system (CMS) required, the facility must develop and submit a site-specific monitoring plan to the EPA Administrator for approval at least 60 days prior to the initial performance evaluation of the CMS. The site-specific monitoring plan must address the following:

1. Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g. on or downstream of the last control device);
2. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;
3. Performance evaluation procedures and acceptance criteria (e.g., calibrations);
4. Ongoing operation and maintenance procedures in accordance with the general requirements of Part 63.8(c)(1), (c)(3), and (c)(4)(ii);
5. Ongoing data quality assurance procedures in accordance with general requirements of Part 63.8(d); and
6. Ongoing recordkeeping and reporting procedures in accordance with the general requirements of Part 63.10(c), (e)(1), and (e)(2)(i).

The following sections represent the site-specific monitoring plan for Boiler No. 8.

2.0 PROCESS DESCRIPTION

2.1 BOILER NO. 8

Boiler No. 8 will fire bagasse as its primary fuel, with ultra-low sulfur No. 2 fuel oil used for startup, shutdown, and as a supplementary fuel. Boiler No. 8 is designed to produce 550,000 pounds per hour (lb/hr) steam as a 1-hour average and 500,000 lb/hr steam as a daily 24-hour average. The boiler is permitted to operate up to 365 days per calendar year [8,760 hour per year (hr/yr)].

Boiler No. 8 utilizes air pollution control equipment consisting of two wet cyclone scrubbers, an electrostatic precipitator (ESP) to remove particulate matter, and a selective non-catalytic reduction system (SNCR) to reduce nitrogen oxides emissions.

3.0 INSTALLATION OF CMS

The Boiler MACT rule requires the installation of the CMS sampling probe or other interface at a measurement location relative to Boiler No. 8 such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). The following sections describe the CMS probe location with respect to each CMS parameter.

3.1 CO CEMS

The CO CEMS will be installed to determine emissions from the boiler stack and shall have the capability to meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. In accordance with Performance Specification 4 and 4A, CEMS must be installed at an accessible location where the pollutant concentration or emission rate measurements are directly representative or can be corrected so as to be representative of the total emission from the affected facility or at the measurement location cross section.

The measurement location will be: (1) at least two equivalent diameters downstream for the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur; and (2) at least a half equivalent diameter upstream from the effluent exhaust or control device.

The measurement point should be: (1) no less than 1.0 meter (3.3 ft) from the stack or duct wall; or (2) within or centrally located over the centroidal area of the stack or duct cross section.

For Boiler No. 8, the location of the CO CEMS is provided in Appendix A.

3.2 WET SCRUBBER LIQUID FLOW METER

The flow meter for the wet scrubber liquid flow rate will meet the following requirements:

1. Locate the flow sensor and other necessary equipment in a position that provides a representative flow.
2. Flow or abnormal velocity distributions will be minimized due to upstream and downstream disturbances.

For Boiler No. 8, a flow meter will be located on the scrubber liquid supply line which flows to each of the two wet scrubbers.

3.3 WET SCRUBBER PRESSURE DROP

The pressure sensor for the wet scrubber will meet the following requirements:

1. Locate the pressure sensor and other necessary equipment in a position that provides a representative pressure.
2. Pulsating pressure, vibration, and internal and external corrosion will be minimized or eliminated.

For Boiler No. 8, pressure differential sensors will be located on each wet scrubber. The sensors will be located in the flue gas ductwork, one just upstream of the wet scrubber and one just downstream of the wet scrubber.

3.4 WET SCRUBBER pH

The pH sensor for the scrubber water will meet the following requirements:

1. The pH sensor will be located in a position that provides a representative measurement of scrubber effluent pH.
2. The location will be at a point where the fluid is properly mixed and representative.

For Boiler No. 8, a pH monitor will be located on each wet scrubber, on the scrubber effluent discharge line which flows to the spent scrubbing slurry pit.

3.5 ESP VOLTAGE AND SECONDARY CURRENT

Equipment will be used to continuously monitor and record voltage and secondary current to the ESP. Each of the fields of the ESP will be monitored individually. Total power input to the ESP will be calculated based on the product of the voltage and current readings for each field, and by summing the power inputs to each individual field. Data collection and reduction will be performed by the CISCO data acquisition system.

4.0 PERFORMANCE AND EQUIPMENT SPECIFICATIONS

The performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems are summarized below.

4.1 CO CEMS

The CO CEMS vendor is Custom Instrumentation Services Corporation (CISCO). Performance and equipment specifications are provided as Appendix A.

4.2 WET SCRUBBER LIQUID FLOW

The flow sensor will have a sensitivity of at least 2 percent of the flow rate. Performance and equipment specifications are provided as Appendix A.

4.3 WET SCRUBBER PRESSURE DROP

The pressure sensor will have a gauge with a minimum tolerance of 1.27 centimeters (0.5 inches) of water, or a transducer with a minimum tolerance of 1 percent of the pressure range. Performance and equipment specifications are provided as Appendix A.

4.4 WET SCRUBBER pH

pH sensors will be utilized to monitor the pH of the scrubber effluent from each wet scrubber. Data collection and reduction will be performed by the CISCO data acquisition system. Performance and equipment specifications are provided as Appendix A.

4.5 ESP VOLTAGE AND SECONDARY CURRENT

The Boiler MACT rule does not contain minimum specifications for the equipment used to monitor and record voltage and secondary current to the ESP. Power input will be calculated based on the voltage and current. Data collection and reduction will be performed by the CISCO data acquisition system. Performance and equipment specifications are provided as Appendix A.

5.0 PERFORMANCE EVALUATION PROCEDURES

The performance evaluation procedures and acceptance criteria (e.g., calibrations) are summarized in the following sections.

5.1 CO CEMS

The performance of the CO CEMS will be evaluated through the relative accuracy test audits (RATA). CO RATA testing will meet requirements of Performance Specification 4 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 10 for CO in Appendix A of 40 CFR 60.

An oxygen (O_2) monitor is also required in order to adjust the stack gas CO concentrations to 7 percent O_2. The O_2 content RATA testing will meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60.

5.2 WET SCRUBBER LIQUID FLOW

The performance of the wet scrubber liquid flow meter will be evaluated with calibrations as specified by the manufacture's operating and maintenance procedures. Data collection and reduction will be performed by the CISCO data acquisition system. A flow sensor calibration check will be performed at least semiannually.

5.3 WET SCRUBBER PRESSURE DROP

The performance of the wet scrubber pressure drop gauges will be evaluated with calibrations as specified by the manufacture's operating and maintenance procedures. Data collection and reduction will be performed by the CISCO data acquisition system. In addition, the following activities will be performed:

1. The pressure tap will be checked daily for pluggage.
2. A manometer will be used to check the gauge calibration quarterly, and the transducer monthly.

3. Calibration checks will be performed any time the sensor exceeds the manufacture's specified maximum operating pressure range or a new sensor will be installed.

5.4 WET SCRUBBER pH

The pH meter's calibration will be checked on at least two points every 8 hours of process operation. Data collection and reduction will be performed by the CISCO data acquisition system.

5.5 ESP VOLTAGE AND SECONDARY CURRENT

The performance of the ESP voltage and secondary current meters will be evaluated as specified by the manufacture's operating and maintenance procedures. Data collection and reduction will be performed by the CISCO data acquisition system.

6.0 OPERATION AND MAINTENANCE PROCEDURES

Ongoing operation and maintenance procedures shall be in accordance with the general requirements of 63.8(c)(1), (c)(3), and (c)(4)(ii).

63.8(c). Operation and maintenance of continuous monitoring systems.

(1) The owner or operator of an affected source shall maintain and operate each CMS as specified in this section, or in a relevant standard, and in a manner consistent with good air pollution control practices.

(i) The owner or operator of an affected source must maintain and operate each CMS as specified in §63.6(e)(1).

(ii) The owner or operator must keep the necessary parts for routine repairs of the affected CMS equipment readily available.

(iii) The owner or operator of an affected source must develop and implement a written startup, shutdown, and malfunction plan for CMS as specified in §63.6(e)(3).

(3) All CMS shall be installed, operational, and the data verified as specified in the relevant standard either prior to or in conjunction with conducting performance tests under §63.7. Verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system.

(4) Except for system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level calibration drift adjustments, all CMS, including COMS and CEMS, shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(ii) All CEMS for measuring emissions other than opacity shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

6.1 <u>CO/O_2 CEMS</u>

Operation and maintenance of the CO CEMS will be performed in accordance with the manufacture's specifications (Siemens Model 6E and Ametek O_2 monitor), and as described in the CISCO CEM System Operation Manual.

6.2 WET SCRUBBER LIQUID FLOW

The wet scrubber liquid flow monitors will be operated and maintained consistent with the manufacture's specifications and good operating practices.

6.3 WET SCRUBBER PRESSURE DROP

The wet scrubber pressure monitors will be operated and maintained consistent with the manufacture's specifications and good operating practices.

6.4 WET SCRUBBER pH

The wet scrubber pH monitors will be operated and maintained consistent with the manufacture's specifications and good operating practices.

6.5 ESP VOLTAGE AND SECONDARY CURRENT

The ESP voltage and secondary current monitors will be operated and maintained consistent with the manufacture's specifications and good operating practices.

7.0 DATA QUALITY ASSURANCE PROCEDURES

The ongoing data quality assurance procedures shall be in accordance with the general requirements of Part 63.8(d).

63.8 (d). Quality control program.

(1) The results of the quality control program required in this paragraph will be considered by the Administrator when he/she determines the validity of monitoring data.

(2) The owner or operator of an affected source that is required to use a CMS and is subject to the monitoring requirements of this section and a relevant standard shall develop and implement a CMS quality control program. As part of the quality control program, the owner or operator shall develop and submit to the Administrator for approval upon request a site-specific performance evaluation test plan for the CMS performance evaluation required in paragraph (e)(3)(i) of this section, according to the procedures specified in paragraph (e). In addition, each quality control program shall include, at a minimum, a written protocol that describes procedures for each of the following operations:

(i) Initial and any subsequent calibration of the CMS;

(ii) Determination and adjustment of the calibration drift of the CMS;

(iii) Preventive maintenance of the CMS, including spare parts inventory;

(iv) Data recording, calculations, and reporting;

(v) Accuracy audit procedures, including sampling and analysis methods; and

(vi) Program of corrective action for a malfunctioning CMS.

(3) The owner or operator shall keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. Where relevant, e.g., program of corrective action for a malfunctioning CMS, these written procedures may be incorporated as part of the affected source's startup, shutdown, and malfunction plan to avoid duplication of planning and recordkeeping efforts.

7.1 CO CEMS

Quality assurance procedures for all CEMSs shall conform to the requirements of Appendix F in 40 CFR 60, Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determinations. U.S. Sugar will follow the quality assurance program conforming to the requirements of Appendix F. U.S. Sugar personnel will perform daily quality assurance procedures. The Quality Control (QC) plan includes the following:

- Calibration of CEMS.
- Calibration drift (CD) determinations and adjustments of CEMS – must check, record, and quantify the CD at two concentration values at least once daily.
- Preventive maintenance of CEMS (including spare parts inventory). Data recording, calculations, and reporting.
- Accuracy audit procedures including sampling and analysis methods – Each CEMS must be audited at least once per calendar quarter.
- Program of corrective action for malfunctioning CEMS.

7.2 WET SCRUBBER LIQUID FLOW

On-going data quality assurance procedures for the liquid flow rate monitors will consist of semi-annual calibrations according to the manufacturer's procedures.

7.3 WET SCRUBBER PRESSURE DROP

The performance of the wet scrubber pressure drop gauges will be evaluated with calibrations as specified by the manufacture's operating and maintenance procedures. Data collection and reduction will be performed by the CISCO data acquisition system.

1. The pressure tap will be checked daily for pluggage.
2. A manometer will be used to check the gauge calibration quarterly, and the transducer monthly.
3. Calibration checks will be performed any time the sensor exceeds the manufacture's specified maximum operating pressure range or a new sensor will be installed.

7.4 WET SCRUBBER pH

To provide on-going data quality, the pH meter's calibration will be checked on at least two points every 8 hours of process operation. Data collection and reduction will be performed by the CISCO data acquisition system.

7.5 ESP VOLTAGE AND SECONDARY CURRENT

As part of the on-going quality control program, U.S. Sugar will operate and calibrate the voltage and secondary current meters according to the manufacturer's procedures. Calibrations will be performed at lest semi-annually.

8.0 RECORDKEEPING AND REPORTING PROCEDURES

Recordkeeping and reporting will be performed in accordance with the general requirements of Part 63.10(c), (e)(1), and (e)(2)(i).

63.10(c). Additional recordkeeping requirements for sources with continuous monitoring systems. In addition to complying with the requirements specified in paragraphs (b)(1) and (b)(2) of this section, the owner or operator of an affected source required to install a CMS by a relevant standard shall maintain records for such source of –

(1) All required CMS measurements (including monitoring data recorded during unavoidable CMS breakdowns and out-of-control periods);

63.10(e). Additional reporting requirements for sources with continuous monitoring systems –

(1) General. When more than one CEMS is used to measure the emissions from one affected source (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required for each CEMS.

(2) Reporting results of continuous monitoring system performance evaluations.

(i) The owner or operator of an affected source required to install a CMS by a relevant standard shall furnish the Administrator a copy of a written report of the results of the CMS performance evaluation, as required under §63.8(e), simultaneously with the results of the performance test required under §63.7, unless otherwise specified in the relevant standard.

U.S. Sugar is developing and will implement a data acquisition and handling system (DAHS) to record all data from the CMS. The DAHS specification, prepared by CISCO, is contained in Appendix B. The DAHS system is designed to retrieve and store all readings from the CMS associated with Boiler No. 8, convert the data to appropriate averages and averaging times, and provide written reports and records.

APPENDIX A

PERFORMANCE AND EQUIPMENT SPECIFICATIONS FOR CUSTOM INSTRUMENTATION SERVICES CORPORATION (CISCO)

1.0 GENERAL.

This specification covers the requirements a Continuous Emission Monitoring System (CEMS) and equipment for the U S Sugar Mill in Clewiston, Florida.

It is not the intent of McBurney to specify all the technical requirements in these specifications, nor to set forth all of the requirements covered by applicable codes, specifications and standards. The design of the equipment and standard accessories as well as materials used in the fabrication by the Vendor shall comply with all applicable Federal and local statutes in addition to the latest regulations, specifications and requirements in effect at date of purchase order.

The CEMS equipment will operate continuously with scheduled maintenance outages.

2.0 PROJECT SCHEDULE.

April 26, 2004	RFP submitted to Vendor
April 14, 2004	Vendor submits proposal to McBurney
April 18, 2004	McBurney selects vendor and issues purchase order
(By Vendor)	Submittal of drawing
(By Vendor)	Submittal of spare parts list
(By Vendor)	Submittal of operating manual
Aug. 15, 2004	Material required on site
January, 2005	Commercial operation
Jan. 30, 2006	End of mechanical warranty period

3.0 SITE CONDITIONS.

The equipment will be designed for the following ambient and environmental conditions at the jobsite:

Location		Indoors
Plant Elevation	(ft/ASL)	20

Outdoor Air Conditions:

Paper Mill	(yes/no)	No
Salt Laden	(yes/no)	No

4.0 GUARANTEES.

Vendor shall guarantee all equipment furnished to be free from defects in material, workmanship and design for the twelve-month warranty period from date of commercial operation. Vendor shall guarantee to repair or replace, at his own expense, the equipment or any part thereof found to be defective during said twelve-month period.

Vendor shall guarantee that equipment design complies with all requirements defined herein.

The equipment is to be the most advanced design possible based upon knowledge available at time of manufacture. Vendor shall be responsible for incorporating in equipment design the latest modifications and advancements which have been found necessary based upon operating experience with equipment furnished for similar application.

5.0 INTRODUCTION

General Background

This document is issued as an invitation to bidders for the supply and installation of continuous emission monitor system for U. S. Sugar Corporation (USSC) Boiler No. 8 located in Clewiston, Florida. This document describes the system requirements to be met in the bid responses of the CEM vendors to secure under contract all material, design, engineering, installation, supervision and training services for the CEMS components and systems

USSC has been authorized to construct Boiler No. 8 (EU-028), a new bagasse-fired boiler with a maximum heat input rate of 1,030 MMBtu/hr. USSC is authorized to perform the proposed work in accordance with the conditions of the air permit. The air permit is included as Attachment A. Certain of these conditions require that USSC install, calibrate, operate and maintain CEMS to continuously measure and record the following Boiler No. 8 exhaust concentrations:

Carbon Monoxide (CO);
Nitrogen Oxides (NOx); and
Oxygen (O2)

Various recordkeeping and reporting requirements associated with these systems are also required.

6.0 TERMS AND CONDITIONS OF BIDS

This is an invitation to submit a bid based on the materials, systems and equipment requirements described in this document. All bids must be submitted in accordance with the specification and information contained herein, as well as with any addenda, if required, issued by the purchaser.

It shall be the responsibility of each bidder, before submitting a bid, to:

6.1 Examine the bid documents and/or bid package thoroughly.

6.2 Become familiar with all local conditions that may affect costs, progress, performance or furnishing of the work.

6.3 Consider all federal, state and local laws and regulations that may affect cost, progress, performance or furnishing of the work.

6.4 Notify McBurney, in writing, of all conflicts, errors or discrepancies in the bid documents and or/ bid package.

7.0 INSTRUCTIONS TO THE BIDDER

7.1 The currency used for said bid will be in American Dollars.

7.2 The bidder shall consider the nature of the work to be done as well as the difficulties involved in its proper execution.

7.3 The bid shall include all costs deemed necessary to cover all contingencies essential to the supply and installation of the specified components and systems.

7.4 Any cost encountered, which is not specifically itemized in the bid, shall not be incurred unless specifically agreed upon, in writing, by McBurney.

7.5 No additional compensation will be allowed for extra work incurred on the part of the Contractor due to bidder's failure to notice any existing condition which may cause the additional labor.

7.6 Sealed Bid responses shall be concise following the format and numbering of this specification. Items not requiring responses shall be acknowledged by the bidder as being understood.

8.0 RIGHTS OF PURCHASER

8.1 The term "Purchaser" throughout the entirety of this Invitation To Bidders document shall be interpreted as McBurney and its designated agents.

8.2 The Purchaser reserves the right to accept any bid or, at its discretion, reject any or all bids for whatever reason it deems appropriate.

8.3 Receipt of a bid response does not obligate the Purchaser to pay any expenses incurred by the bidder in preparation of the bid response or obligate the Purchaser in any other respect.

8.4 The Purchaser reserves the right to modify the specifications contained in he Invitation To Bidders anytime during the bidding period.

8.5 Only changes issued as an addendum will be binding upon the Purchaser. No verbal instructions or interpretations of requirements shall be accepted.

9.0 SCOPE OF WORK

McBurney intends, by soliciting responses to this Invitation To Bidders, to contract with a company to supply a CEM system for USSC Boiler No. 8. The CEM installation will be a joint effort by McBurney Corp. construction personnel and McBurney electrical subcontractor performing main boiler installation. The CEM supplier will be required to provide technical support during the installation, calibration, start-up support, and certification testing. The CEM system will include equipment for measurement of the following exhaust gas concentrations:

- Carbon Monoxide (CO)
- Nitrogen Oxides (NOx)
- Oxygen (O2)

The project also includes the installation, and calibration of an in stack continuous volumetric flow and temperature monitor, which will be utilized to calculate mass emission rates from the measure pollutant concentrations. Due to the highly variable nature of bagasse fuel, EPA Method 19 will not be suitable for calculating continuous mass emissions.

9.1 The CEMS monitors and DAHS system will be housed in the Boiler No. 8 Precipitator Electrical room and will not require the bidder to provide a CEMS shelter. The Precipitator Electrical room will be located at grade adjacent to the stack. See CEMS location in Attachment B.

9.2 The CEMS must be capable of demonstrating compliance with the permitted emission limits for NOx and CO for Boiler No. 8, which are:

9.2.1 CO - 0.38 lb/MMBtu, 12-month rolling average, excluding periods of startup, shutdown, and malfunction.
9.2.2 CO -- 1,285 tons per 12-month rolling average, including periods of startup, shutdown, and malfunction.
9.2.3 NOx – 0.14 lb/MMBtu, 30-day rolling average, excluding periods of startup, shutdown, and malfunction.

9.3 Various recordkeeping and reporting requirements, associated with these systems are also required. The contract will also include follow-up training of specified U.S. Sugar employees on CEMS operation, quality assurance, and maintenance.

9.4 The NOx monitor shall be installed to determine emissions from the boiler stack and shall meet the requirement of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. As required by the air construction permit (see Attachment A), the monitor shall have a maximum span value of 250 ppmvd.

9.5 The CO process monitor shall be installed to determine emissions from the boiler stack and shall have the capability to meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60.

9.6 The oxygen monitor shall be installed at each CO and NOx monitor location to correct the measured CO and NOx concentrations to the required oxygen concentrations. The O2 monitor shall meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

9.7 Stack gas flow rate and temperature monitors shall be installed to calculate the mass emission rates of NOx and CO.

9.8 Data reporting criteria are also specified in the air permit. A data acquisition system must be installed to record 1-hour averages, 24-hour averages, 30-day averages, data exclusion parameters, and monitor availability have to be met by the CEMS.

9.9 Note that USSC has utilized a stack test firm in the past (Air Consulting & Engineering, Gainesville, Fl), and this firm may be used to perform the RATA. Bidders also have the option of using a different stack testing firm.

10.0 GENERAL REQUIREMENTS

10.1 Bidders are to deliver one original and signed hardcopy response to this Invitation To Bidders.

10.2 Responses to this Invitation To Bidders shall follow the format of this document and at minimum will contain the information requested herein.

10.3 Bidders shall provide catalogs, brochures and/or other technical information detailing system components and materials, standard and optional features, with Bidders response.

10.4 Bidders will supply a list of five (5) customer references that have equipment and services with comparable system specification as requested in this Invitation To Bidders

10.5 Bids shall contain best and final offers.

10.6 Responses shall contain one sample copy of any and all documents that will need to be executed by USSC.

10.7 Bidders shall include the current rate or charge for maintenance and repair service covering system adds, moves and changes as well as non-warranted damage on both a contract and time and materials basis. Bidder shall also state and guarantee annual, fixed, not to exceed, costs for these services for a period of five (5) years.

10.8 McBurney shall not be responsible for payment of any Add-Ons, Subsequent Additions or Deletions and/or Optional Equipment and Services that have not been authorized in writing by McBurney.

11.0 TECHNICAL REQUIREMENTS

11.1 NOx Monitor.
The NOx monitor shall be installed to determine NOx emissions from Boiler No. 8 and shall meet the requirement of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have a maximum span value of 250 ppmvd.

11.2 40 CFR 60 Appendix A Performance Specification 2, Specifications and Test Procedures for SO2 and NOx Continuous Emission Monitoring Systems in Stationary Sources.

11.2.1 Data Recorder Scale. The CEMS data recorder output range must include zero and a high-level value. The high-level value shall be 250 ppmvd as specified by Air Permit No. PSD-FL-333

11.2.2 The CEMS design should allow the determination of calibration drift at the zero and high-level values. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20% of the high-level value) and at a value between 50 and 100 % of the high-level value.

11.2.3 CEMS must be designed to meet the following calibration drift performance specification; CEMS calibration must not drift or deviate from the reference value of the cylinder gas, gas cell, or optical filter by more than 2.5 percent of the established span value.

11.2.4 CEMS must meet the following relative accuracy performance specifications of Section 13.2 of 40 CFR 60 Appendix A Performance Specification 2.

11.2.5 CEMS must be installed at an accessible location where the pollutant concentration or emission rate measurements are directly representative or can be corrected so as to be representative of the total emission from Boiler No.8, or at the measurement location cross section. The CEM measurement location will be determined by the contractor with approval by USSC.

11.2.6 It is suggested that the measurement location be (1) at least two equivalent diameters downstream from the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur and (2) at least a half equivalent diameter upstream from the effluent exhaust or control device.

11.2.7 Point CEMS. It is suggested that the measurement point be (1) no less than 1.0 meter (3.3 ft) from the stack or duct wall or (2) within or centrally located over the centroidal area of the stack or duct cross section.

11.2.8 Path CEMS. It is suggested that the effective path (1) be totally the inner area bounded by a line 1.0 meter (3.3 ft) from the stack or duct wall, or (2) at have at least 70 percent of the path within the inner 50 percent of the stack or duct cross-sectional area, or (3) be centrally located over any part of the centroidal area.

11.3 40 CFR 60 Appendix A, Method 7E

11.3.1 The NOx CEM shall be dilution or fully extractive. The bidder shall recommend the type of sample system and bid accordingly.

11.3.2 The NOx CEMS shall include a sample probe (dilution or fully extractive), sample line, calibration valve assembly, moisture removal system (fully extractive only), particulate filter, sample pump, sample flow rate control, sample gas manifold, and NO2 to NO converter, NOx analyzer, and data recorder.

11.3.3 Sample probe shall be glass or stainless steel or equivalent, of sufficient length to traverse the sample points. The sample probe shall be heated to prevent condensation.

11.3.4 If fully extractive system, the sample line shall be heated (sufficient to prevent condensation) stainless steel or Teflon tubing, to transport the sample gas to the moisture removal system.

11.3.5 All sample transport lines shall be Teflon or stainless steel tubing.

11.3.6 The sample probe shall include a three way valve assemble, or equivalent for blocking the sample gas flow and introducing calibration gases to the measurement system at the outlet of the sampling probe when in calibration mode

11.3.7 If required the moisture removal system shall be of the refrigerator-type condenser or similar device to remove condensate on a continuous basis while maintaining minimal contact between the condensate and the sample gas.

11.3.8 An in-stack or heated out of stack filter shall be borosilicate or quartz glass wool, or glass fiber mat.

11.3.9 If fully extractive system, a leak free sample pump shall be used to pull the sample gas through the system at a rate sufficient to minimize the response time of the measurement system. The sample pump shall be constructed of a material non-reactive to the sample gas.

11.3.10 A sample flow rate control valve and rotameter or equivalent shall be used to maintain a constant sampling rate within 10 percent

11.3.11 A sample gas manifold to divert a portion of the sample gas stream to the analyzer, and the remainder to the by-pass discharge vent. The sample manifold shall also include provisions for introducing calibration gases directly to the analyzer.

11.3.12 The CEMS shall include a NO2 to NO converter.

11.3.13 The NOx analyzer shall be based on the principles of chemiluminescence to determine continuously the NOx concentration in the sample gas stream. The analyzer shall have a calibration error of less than +- 2% of the span for the zero, mid-range, and high-range calibration gases. The sample system bias shall be less than +- 5% of the span for the zero, and mid- or high-range calibration gases. The zero and calibration drift shall be less than +- 3% of span.

11.3.14 NOx calibration gases shall be NO in N2. Three calibration gases shall be used: High-range equivalent to 80 to 100 percent of the span, Mid-range equivalent to 40 to 60 percent of the span, and a zero gas less than 0.25% of the span.

11.3.15 The data recorder shall record data at a resolution of at least 0.5% of the span.

11.4 Air Permit No. PSD-FL-333

11.4.1 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The CEMS must use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed to operate to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provision to determine moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0%

moisture). Final results shall be recorded in terms of lb/hr and lb/MMBtu.

11.4.2 Data exclusion. Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEM shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions. CEMS shall include boiler operational inputs to identify and record periods of startup, shutdown and malfunction and record boiler heat input (MMBtu/hr) back calculated from the steam generation. Although data shall be recorded during these periods, data during these periods will not be included in the 30-day rolling averages reported in the quarterly report.

11.4.3 CEMS shall be designed to meet monitor availability of 95% or greater in any calendar quarter.

11.4.4 30-Day Rolling Averages. The CEMS shall produce 30-day rolling averages by averaging all 1-hour averages for 30 successive boiler-operating days. The boiler-operating day begins and ends at midnight of each day and includes any day that fuel is combusted. Final results shall be recorded in terms of lb/MMBtu, and exclude data during startup, shutdown, and malfunction.

11.5 CO Process Monitor.

The CO process monitor shall be installed to determine CO emissions from Boiler No.8 and shall have the capability to meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have automatic dual span capabilities with maximum span values of 1,000 ppmvd and 10,000 ppmvd.

11.6 40 CFR 60 Appendix A Performance Specification 4
Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

11.6.1 Data Recorder Scale. The CEMS data recorder output range must include zero and a high-level value. The monitor shall have automatic dual span capabilities with maximum span values of 1,000 ppmvd and 10,000 ppmvd as specified by Air Permit No. PSD-FL-333

11.6.2 The CEMS design should allow the determination of calibration drift at the zero and high-level values. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20% of the high-level value) and at a value between 50 and 100 % of the high-level value.

11.6.3 CEMS must be designed to meet the following calibration drift requirements; CEMS calibration must not drift or deviate from the reference value of the calibration gas, gas cell, or optical filter by more than 5 percent of the established span value for 6 out of 7 test days.

11.6.4 CEMS must meet the following Relative Accuracy requirements; RA of the CEMS must be no greater than 10 percent when the average RM value is used to calculate RA or 5 percent when the applicable emission standard is used to calculate RA.

11.6.5 CEMS must be installed at an accessible location where the pollutant concentration or emission rate measurements are directly representative or can be corrected so as to be representative of the total emission from Boiler No. 8 or at the measurement location cross section. The CEM measurement location will be determined by the contractor with approval by USSC.

11.6.6 The CEM measurement location will be identical as that determined for the NOx CEM measurement location. The CO CEM shall share the sample system of the NOx CEM. The CO monitor shall pull its sample from the common sample gas manifold.

11.7 40 CFR 60 Appendix A, Method 10,
Determination of Carbon Monoxide Emissions from Stationary Sources.
The CO CEMS shall include the following components:

11.7.1 The CO CEM shall be dilution or fully extractive. The bidder shall recommend the type of sample system and bid accordingly.

11.7.2 Stainless steel probe or sheathed Pyrex glass, equipped with a filter to remove particulate matter. The CO CEM shall share the sample extraction system specified in the NOx CEM specification.

11.7.3 Air-cooled condenser or equivalent to remove any excess moisture. Shared with the NOx CEM.

11.7.4 Non-dispersive infrared spectrometer (NDIR), or equivalent carbon monoxide analyzer.

11.7.5 Silica gel drying tube.

11.7.6 Calibration gases at the same levels defined for NOx CEMS.

11.7.7 CO2 removal trap containing ascarite.

11.7.8 Needle valve to adjust sample flow.

11.7.9 Flow rate meter, rotameter or equivalent to adjust sample flow to 0 to 1.0 liter per minute through NDIR.

11.7.10 Data acquisition and handling system (DAHS), see Data Acquisition and Report Generation.

11.8 Air Permit No. PSD-FL-333.

11.8.1 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The CEMS must use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed to operate to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provision to determine moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of lb/MMBtu.

11.8.2 Data exclusion. Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEM shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions. CEMS shall include boiler operational inputs to identify and record periods of startup, shutdown and malfunction and record boiler heat input (MMBtu/hr) back calculated from the steam generation. Although data shall be recorded during these periods, data during these periods will not be included in the lb/MMBtu 12-month rolling averages reported in the quarterly report.

11.8.3 Determination of the 12-month rolling average CO TPY will include the emissions during startup, shutdown, and malfunction for comparison to the permit limit of 1,285 tons of CO during any consecutive 12-months.

11.8.4 CEMS shall be designed to meet monitor availability of 95% or greater in any calendar quarter.

11.8.5 12-Month Rolling Averages. The CEMS shall produce 12-month rolling averages for CO by averaging all valid 1-hour averages (in terms of lb/MMBtu) for each boiler operating day over each 12-month period. The initial 12-month averaging period begins upon boiler startup and ends 12 months later and includes any day that fuel is combusted. Thereafter, a 12-month average must be calculated for each subsequent month.

11.9 Diluent Monitors.

An oxygen monitor shall be installed to correct the measured CO and NOx concentrations to the required oxygen concentrations. The O2 monitor shall meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

11.9.1 The installation and measurement location specification calculations and data analysis shall be the same as those specified in 40 CFR 60 Appendix A Performance Specification 2.

11.9.2 CEMS must be designed to meet the following calibration drift requirements; CEMS calibration must not drift by more than 0.5 percent from the reference value of the calibration gas, gas cell, or optical filter.

11.9.3 CEMS must meet the following Relative Accuracy requirements; RA of the CEMS must be no greater than 1.0 percent of O2.

11.10 Stack Volumetric Flow Rate and Temperature Monitor

11.10.1 CEMS will include a continuous monitor for stack gas volumetric flow rate and temperature. Stack gas flow rate standard cubic feet per hour (SCFHD) will be recorded and utilized to calculate the mass emission rates (lb/hr). The lb/hr emission rates will be divided by the heat input (MMBtu/hr) to calculate lb/MMBtu on an hourly basis. All hourly averages will be stored in the data acquisition system for report preparation. The heat input will be provided by USSC as and electronic signal to the CEMS.

11.10.2 The volumetric flow monitor will be based on differential pressure measuring system or equivalent system, bidder to recommend and bid accordingly.

11.10.3 The measurement location will meet the minimum requirements of 40 CFR Part 60 Method 1. Location at least 8 diameters downstream and 2 upstream of any flow disturbance.

11.11 Data Acquisition and Handling System and Report Generation.

11.11.1 The CEMS shall include a data acquisition and handling system (DAHS) capable of producing and report generating system as described below:

11.11.2 The CEMS DAHS shall interface to the Boiler No. 8 control system (PLC) via ModBus RTU connection and CEMS will be ModBus slave in communication with the PLC, which will be through the ModBus communication link or hardwired analog inputs via vendor supplied data logger.

11.11.3 The CEMS DAHS shall monitor and record those parameters identified in Attachment C, USSC Boiler 8 Monitoring Requirements. Note that in addition to monitoring and recording CEM information, the CEM DAHS will also be required to record steam parameters, fuel parameters, ESP parameters, SNCR parameters, wet cyclone parameters, and Boiler 8 startup, shutdown, and malfunction data.

11.11.4 The CEM DAHS shall perform all short term (30day) and annual totalization and shall be based on Dell or equal PC with a minimum on line archive of 5 years. The CEMS system shall be capable of running without DAHS PC for up to 30 days and return of DAHS PC to operation through simple synchronization with data logger.

11.11.5 As an option please quote a DAHS with the capacity to integrate four additional boilers in the future.

11.11.6 The DAHS system shall be designed to operate and produce quarterly reports automatically with the least USSC operator or other personnel assistance as physically possible. An example of the required quarterly is provided in Attachment A, Appendix F.

11.11.7 The DAHS shall record 1-hr, 24-hr, 30-day, and 12-month rolling averages.

11.11.8 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The CEMS must use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed to operate to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provision to determine moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of lb/MMBtu.

11.11.9 Data Exclusion. Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEM shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions.

11.11.10 CEMS shall be designed to meet monitor availability of 95% or greater in any calendar quarter.

11.11.11 Periods of startup, shutdown, and malfunction shall not be included in the lb/MMBtu averages, however they shall be included in the tons per year calculation.

11.11.12 The bidder will work with USSC and the boiler manufacture McBurney to interface the CEMS to the Boiler No. 8 to obtain operating data necessary to program the CEMS to automatically produce quarterly reports with data excluded for startup shutdown and malfunction. The parameters likely to be used to determine Boiler operation are as follows:

- Super Heater Steam Temperature
- Bagasse fuel feed
- SNCR ammonia flow
- Others

11.12 Relative Accuracy Test Audits (RATA) Testing.

11.12.1 NOx CEM must be capable of meeting the RATA testing requirements of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60.

11.12.2 CO CEM must be capable of meeting the RATA testing requirements of Performance Specification 4 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60.

11.12.3 Diluent CEM must be capable of meeting the RATA testing requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60.

12.0 QUALITY ASSURANCE

Quality assurance procedures for all CEMS shall conform to the requirements of Appendix F in 40 CFR 60, Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determinations. The contractor will provide USSC with a written operation and maintenance and quality assurance program conforming to the requirements of Appendix F. The contractor will train USSC personnel to perform daily quality assurance procedures.

12.1 The first RATA must be completed by the date of the first performance test required by applicable regulations.

12.2 Develop a written quality control (QC) plan describing the step-by-step procedures of each of the following activities:

12.2.1 Calibration of CEMS, automatic and manual.
12.2.2 Calibration drift (CD) determinations and adjustments of CEMS – must check, record, and quantify the CD at two concentration values at least once daily. The CEMS must be designed to perform the daily CD determinations and adjustments automatically without assistance of USSC or other personnel.
12.2.3 Preventive maintenance of CEMS (including spare parts inventory).
12.2.4 Data recording, calculations, and reporting.
12.2.5 Accuracy audit procedures including sampling and analysis methods – Each CEMS must be audited at least once each calendar quarter

12.12.6 Program of corrective action for malfunctioning CEMS.
12.12.7 Complete schematic diagrams of all instrumentation.
12.12.8 Complete parts list of CEMS, including spare parts and calibration gases.

12.3 Boiler No. 8 Operating Data

12.3.1 USSC is authorized to construct a balanced draft, membrane wall spreader stoker boiler to generate superheated steam at design conditions of 600 psig and 750 deg. F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 550,000 pounds per hour based on a maximum 1-hour heat input of 1030 MMBtu per hour. Rotating feeders, pneumatic spreaders, a traveling gate, and overfire air will be used to fire the primary fuel of bagasse. Low NOx burners will be used to fire distillate oil as a restricted alternate fuel for startup and supplemental uses.

12.3.2 Boiler No. 8 will utilize the following air pollution control equipment:
- Wet cyclone collectors
- Electrostatic precipitator (ESP)
- Selective non-catalytic reduction (SNCR)

13.0 USSC CLEWISTON SITE CONDITIONS.

Attachment B to this document contains the Boiler No. 8 expected stack conditions as well as site layout drawings.

14.0 ENGINEERING AND OPERATING MANUALS.

The Vendor shall supply complete engingeering drawings with the system. As a minimum the following shall be supplied.

14.1 Equipment Arrangement Drawings

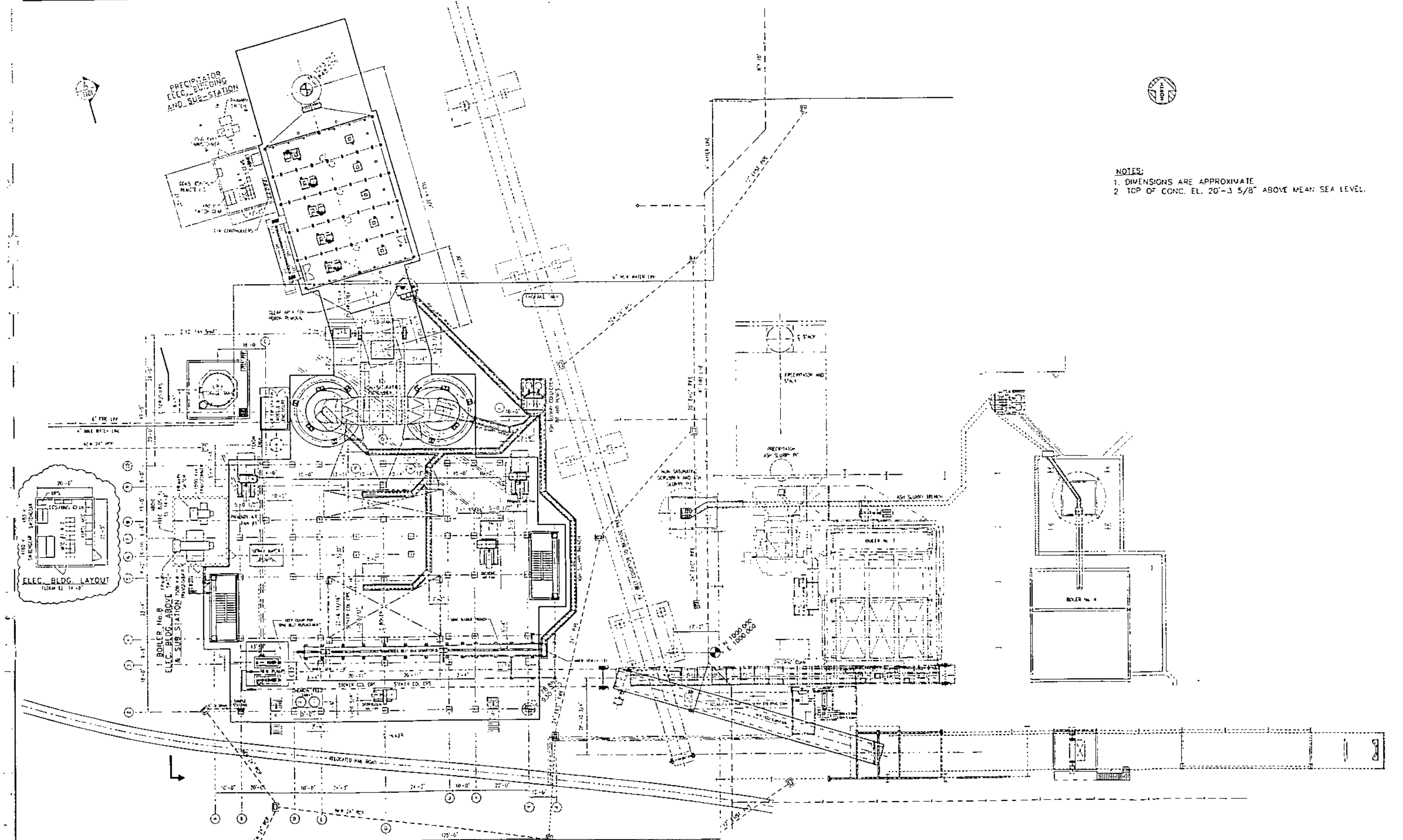
14.2 P& I D Drawings

14.3 Control Logic

14.4 Field Wiring Diagrams

14.5 28 Operation Manuals

Vendor shall tag each major piece of equipment with a stainless steel equipment number.



NOTES:
1. DIMENSIONS ARE APPROXIMATE
2. TOP OF CONC. EL. 20'-3 5/8" ABOVE MEAN SEA LEVEL.

NO.	DRWN	CHKD.	ENG.	APPVD	DATE	REVISION DESCRIPTION
4	SMW	TCG	TCG	TCG	3/18/94	REVISED DRAWING BORDER, SLURRY TRENCH, UNDERGROUND DRAINAGE PIPING, FIRE AND H.P. WATER LINES AND PRECIP. ELEC. BUILDING
						ALSO ADDED SUBMERGED ASH CONV. SLUDGE TRENCH AND LOCATED FANS AND PUMPS. ALSO REVISED FUEL FEED CONVEYORS
						RELEASED FOR DESIGN
1	SMW	TCG			2/3/93	RELOCATED CHEM. DOSE, ADDED SAMPLE STATIONS, REVISED RR TRACKS, REVISED ESP ELEC. BLDG., ADDED UREA STORAGE TANK
2	SMW	TJH			2/23/94	GENERAL REVISION
3	SMW	TJH			3/9/94	RELOCATED UREA TANK, SKID ENCLOSURE, AND RELOCATED ELECTRICAL BUILDINGS

NO	DRWN	CHKD.	ENG.	APPVD	DATE	REVISION DESCRIPTION

magasiner technology

500 000 LB/HR BOILER FOR
UNITED STATES SUGAR CORPORATION
CLEWISTON, FLORIDA.

Thermal Energy Systems

McBurney

BOILER No.8
GENERAL LOCATION
PLAN VIEW

E03022

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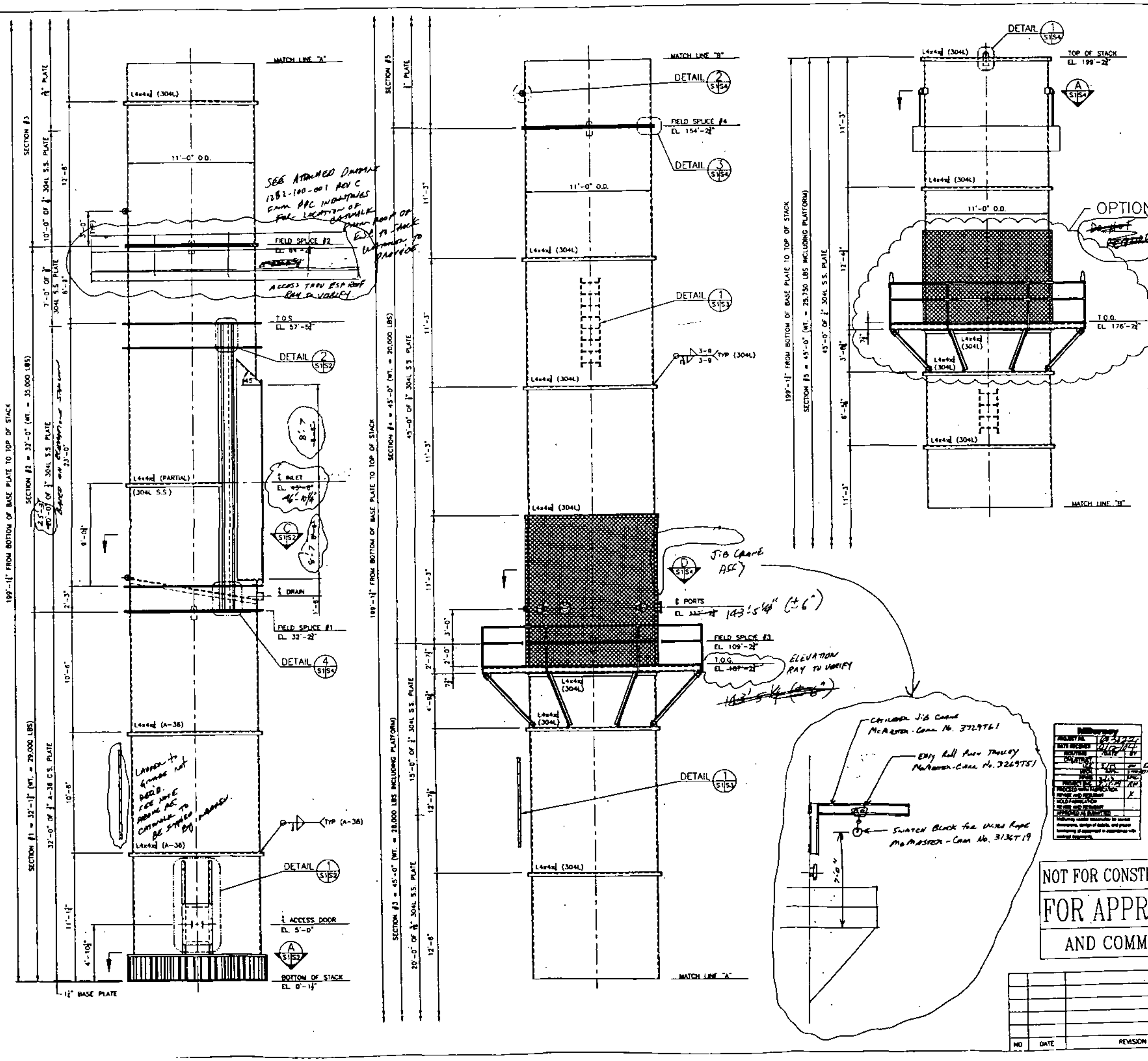


GENERAL NOTES

1. MATERIAL
A. STACK SECTION #1 SHELL PLATES AND ALL EXTERNAL COMPONENT PARTS SUCH AS ANCHOR BOLT CHAIR, STIFFENERS,INLET REINFORCING, AND TUNED MASS DAMPER SHALL CONFORM TO ASTM A-36 CARBON STEEL UNLESS NOTED OTHERWISE. STACK SECTION #2, #3, #4, AND #5 SHELL PLATES ALONG WITH THE OVALLING STIFFENERS, FALSE BOTTOM, AND LIFTING LUGS SHALL CONFORM TO ASTM A240 TYPE 304L STAINLESS STEEL UNLESS NOTED OTHERWISE.
B. ALL PLATFORMS AND LADDERS SHALL CONFORM TO ASTM A-36 AND SHALL BE HOT DIPPED GALVANIZED UNLESS NOTED OTHERWISE.
C. ALL FASTENERS FOR PLATFORMS, LADDERS, ACCESS DOORS, FIELD SPLICES AND ANY OTHER BOLTING REQUIREMENTS SHALL BE GALVANIZED ASTM A-325 FASTENERS UNLESS NOTED OTHERWISE.

2. FABRICATION
ALL WORK SHALL BE FABRICATED IN ACCORDANCE WITH AISC "SPECIFICATIONS FOR STRUCTURAL STEEL BUILDINGS", LATEST EDITION. ALL WELDS SHALL BE MADE ONLY BY WELDING OPERATORS WHO HAVE BEEN PREVIOUSLY QUALIFIED BY TESTS AS PRESCRIBED IN THE AWS "STRUCTURAL WELDING CODE", OR BY THE ASME WELDING CODE, TO PERFORM THE TYPE WORK REQUIRED. ALL BUTT WELDS SHALL BE PRE-QUALIFIED, FULL PENETRATION WELDS AND SHALL DEVELOP THE FULL STRENGTH OF THE SECTION. SHELL GIRTH AND VERTICAL SEAMS SHALL BE COMPLETE PENETRATION BUTT GROOVE WELDS AND TOTALLY WELDED EITHER AUTOMATICALLY OR SEMI-AUTOMATICALLY BY THE SUBMERGED ARC WELDING PROCESS. ALL WELDING ELECTRODES AND FLUX SHALL CONFORM TO THE AWS CODE AND BE EQUIVALENT TO THE BASE METAL IN STRENGTH, CORROSION RESISTANCE, AND WEATHERED APPEARANCE.

3. TOLERANCES
A. BASE RING AND SPLICES MUST BE PERPENDICULAR TO THE STACK CENTERLINE SUCH THAT THE ERECTION OF THE STACK CAN BE PLUMBED TO WITHIN A MAXIMUM DEVIATION OF 1" PER 100' OF HEIGHT.
B. MAXIMUM OUT-OF-ROUNDNESS OF ANY SECTION – DIFFERENCE BETWEEN MINIMUM AND MAXIMUM DIAMETER – LESS THAN 1% OF THE NORMAL DIAMETER.
C. MAXIMUM MISALIGNMENT OF PLATES AT ANY JOINT SHALL NOT TO EXCEED 25% OF THE NORMAL THICKNESS OR 1/8", WHICHEVER IS LESS.
D. ADJOINING PLATE SECTIONS SHALL BE PAIRED FOR FULL 100% DEVELOPMENT.
E. PEAKING OF VERTICAL JOINTS SHALL NOT EXCEED 1/4" AS MEASURED FROM THE TRUE RADIUS OF THE STACK.
F. TEST PORT FLANGES SHALL BE PERPENDICULAR TO THE CENTERLINE TO WITHIN 1/2 DEGREE. FIELD SPLICE FLANGES MUST BE PERPENDICULAR TO THE STACK SHELL WITHIN 1/16".
G. STRUCTURAL PLATES ARE TO BE PURCHASED OF SUFFICIENT LENGTH TO ALLOW FOR ONLY ONE VERTICAL SEAM PER GIRTH. VERTICAL SEAMS ON ADJACENT SECTIONS WILL BE OFFSET BY 90 DEGREES. IN SPECIAL CASES, A MAXIMUM OF TWO VERTICAL SEAMS WILL BE OFFSET AT LEAST BY 90 DEGREES.
H. ALL APPURTENANCES, INCLUDING PLATFORMS AND LADDERS, SHALL BE SHOP ATTACHED TO ENSURE A GOOD FIT. ALL FIELD CONNECTIONS ARE TO BE CLEARLY MATCH MARKED.

4. INSPECTION AND TESTING
MATERIAL TEST REPORTS FOR ALL MATERIAL UTILIZED FOR MAJOR COMPONENTS AND FASTENERS SHALL BE SUBMITTED TO WARREN. THE MATERIAL TEST REPORTS ARE TO BE REQUESTED WHEN THE MATERIAL IS ORDERED AND FORWARDED TO WARREN IMMEDIATELY UPON RECEIPT. THE MSDS SHEETS ON THE TOUCH-UP PAINTS, THINNERS AND ANY OTHER HAZARDOUS MATERIAL IS TO BE INCLUDED WITH THE SHIPMENT OF THE ITEMS.

5. SURFACE PREPARATION
A. ALL SHARP PROJECTIONS SHALL BE GROUND SMOOTH
B. ALL WELD FLUX AND SPLATTER SHALL BE REMOVED BY POWER TOOL CLEANING.
C. ALL CARBON STEEL SURFACES INCLUDING THE INTERIOR OF STACK SECTION #1 ARE TO BE CLEANED PER AN SSPC-SP6 SANDBLAST CLEANING.

6. PAINTING SPECIFICATION
APPLY ONE COAT OF SHERWIN WILLIAMS SILVER BRITE PAINT TO ALL CARBON STEEL SURFACES. INCLUDE 2 GALLONS OF TOUCH-UP PAINT WITH SHIPMENT. ALL TEMPORARY ITEMS THAT MUST BE REMOVED SHALL BE PAINTED YELLOW.

7. LOADING AND SHIPPING
THE STACK WILL BE LOADED AND SECURED ON TRUCKS SUCH THAT PLATES ARE NOT DEFORMED AND THE PAINT SYSTEM IS NOT COMPROMISED. STACK LOADS ARE TO BE DISTRIBUTED OVER LARGE AREAS. POINT LOADS ON PLATES ARE TO BE AVOIDED. TIMBERS USED TO SECURE LOADS ARE TO BE PLACED LONGITUDINALLY, SPANNING AT LEAST TWO STIFFENERS. THE ERECTOR IS TO REMOVE ALL TEMPORARY SPACERS AND BRACES BEFORE COMPLETING THE ERECTION.

FOUNDATION DESIGN LOADS	
DEAD LOAD OF STACK (MIN.)	125.0 KIPS
DEAD LOAD OF STACK (MAX.)	137.5 KIPS
WIND SHEAR AT BASE OF STACK	67.0 KIPS
WIND MOMENT AT BASE OF STACK	7,260 KIP-FT.
WIND CODE:	ASCE 7-98
WIND SPEED	120 MPH
IMPORTANCE FACTOR	1.0
EXPOSURE CATEGORY	EXP. C
SEISMIC LOADS DO NOT CONTROL	

NOT FOR CONSTRUCTION

FOR APPROVAL

AND COMMENT

U.S. SUGAR
P.O. # C203886
SINGLE WALL STACK
BOILER #8

CLEWISTON FLORIDA

STACK ELEVATION

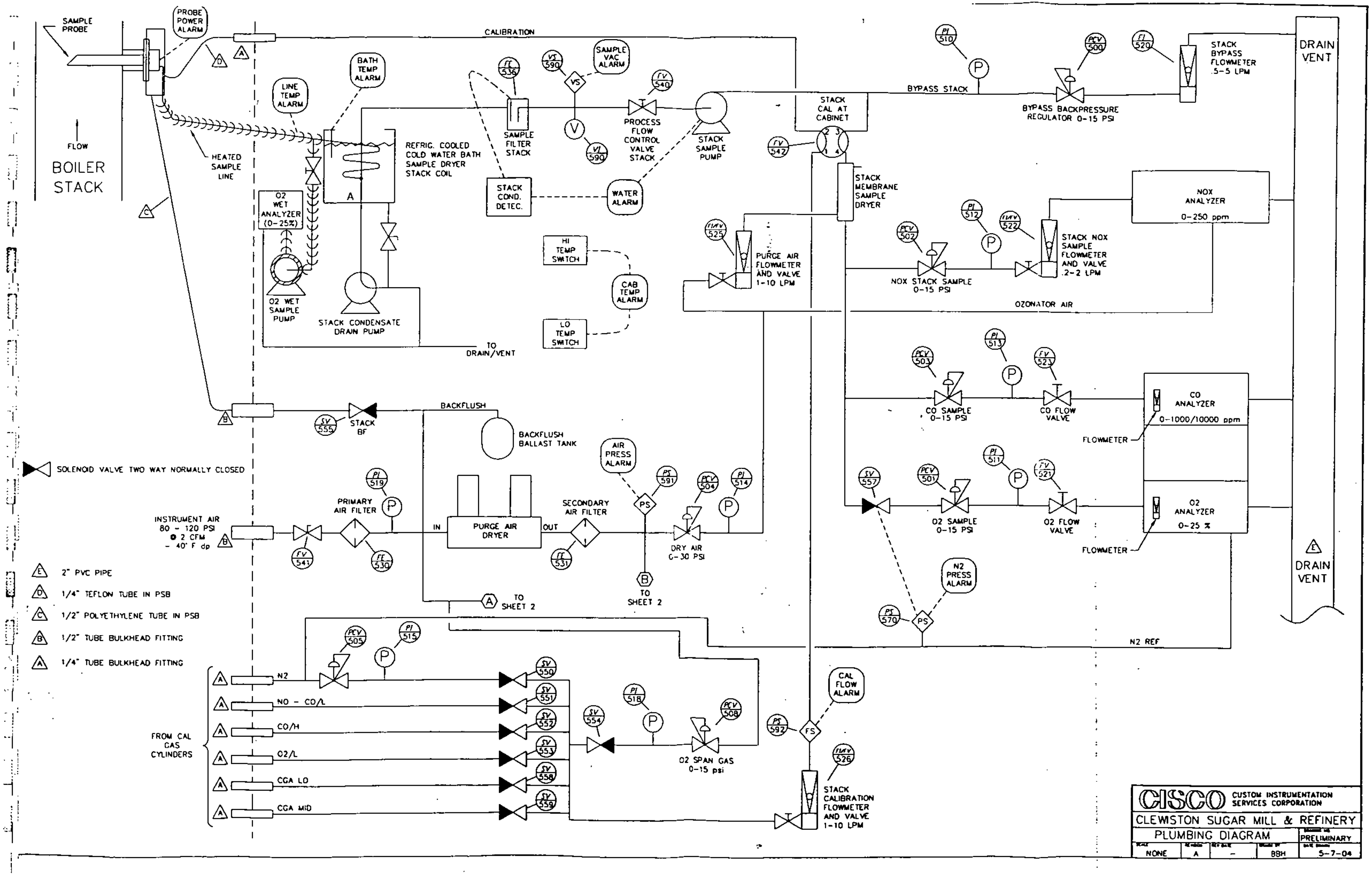
WARREN ENVIRONMENT, INC.
5075 ROSWELL ROAD ATLANTA, GA 30342

	MADE	CHK'D		MADE	CHK'D	
DRAWN:	KHH		DESIGN:			DATE: 01-14-04
						SCALE: AS SHOWN

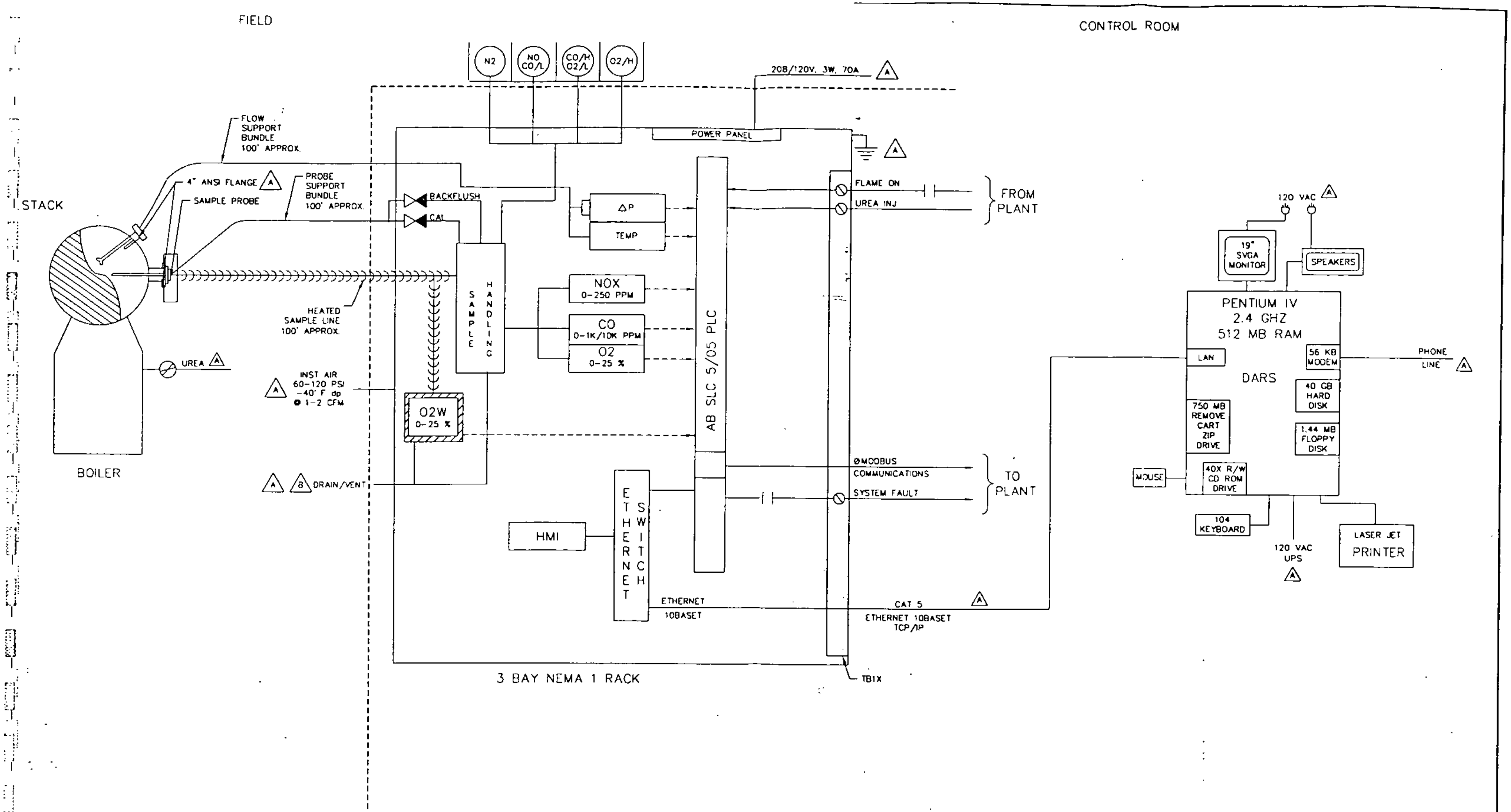
CUSTOMER DWG. NO.

WARREN DWG NO
D03-55-S1-0

NO	DATE	REVISION	MADE	CHK'D



SAMPLE PROBE
PROBE POWER ALARM
CALIBRATION
FLOW
BOILER STACK
HEATED SAMPLE LINE
LINE TEMP ALARM
BATH TEMP ALARM
REFRIG. COOLED COLD WATER BATH SAMPLE DRYER STACK COIL
O2 WET ANALYZER (0-25%)
O2 WET SAMPLE PUMP
STACK CONDENSATE DRAIN PUMP
TO DRAIN/VENT
FC 536
SAMPLE FILTER STACK
VS 590
SAMPLE VAC ALARM
VI 590
FV 540
PROCESS FLOW CONTROL VALVE STACK
STACK SAMPLE PUMP
STACK COND. DETEC.
WATER ALARM
HI TEMP SWITCH
CAB TEMP ALARM
LO TEMP SWITCH
STACK CAL AT CABINET
FV 542
STACK MEMBRANE SAMPLE DRYER
PI 510
BYPASS STACK
PCV 500
BYPASS BACKPRESSURE REGULATOR 0-15 PSI
FI 520
STACK BYPASS FLOWMETER .5-5 LPM
DRAIN VENT
NOX ANALYZER 0-250 ppm
PCV 502
PI 512
FI/FV 522
NOX STACK SAMPLE 0-15 PSI
STACK NOX SAMPLE FLOWMETER AND VALVE .2-2 LPM
FI/FV 525
PURGE AIR FLOWMETER AND VALVE 1-10 LPM
OZONATOR AIR
PCV 503
PI 513
FV 523
CO SAMPLE 0-15 PSI
CO FLOW VALVE
CO ANALYZER 0-1000/10000 ppm
FLOWMETER
SV 557
PCV 501
PI 511
FV 521
O2 SAMPLE 0-15 PSI
O2 FLOW VALVE
O2 ANALYZER 0-25 %
FLOWMETER
DRAIN VENT
N2 PRESS ALARM
PS 570
N2 REF
SV 555
STACK BF
BACKFLUSH
BACKFLUSH BALLAST TANK
SOLENOID VALVE TWO WAY NORMALLY CLOSED
INSTRUMENT AIR 80 - 120 PSI @ 2 CFM - 40° F dp
FV 541
PRIMARY AIR FILTER
PI 519
FC 530
IN
PURGE AIR DRYER
OUT
SECONDARY AIR FILTER
FC 531
AIR PRESS ALARM
PS 591
PCV 504
PI 514
DRY AIR 0-30 PSI
TO SHEET 2
TO SHEET 2
2" PVC PIPE
1/4" TEFLON TUBE IN PSB
1/2" POLYETHYLENE TUBE IN PSB
1/2" TUBE BULKHEAD FITTING
1/4" TUBE BULKHEAD FITTING
FROM CAL GAS CYLINDERS
N2
NO - CO/L
CO/H
O2/L
CGA LO
CGA MID
PCV 505
PI 515
SV 550
SV 551
SV 552
SV 553
SV 558
SV 559
SV 554
PI 518
PCV 508
O2 SPAN GAS 0-15 psi
CAL FLOW ALARM
PS 592
FI/FV 526
STACK CALIBRATION FLOWMETER AND VALVE 1-10 LPM
CISCO CUSTOM INSTRUMENTATION SERVICES CORPORATION
CLEWISTON SUGAR MILL & REFINERY
PLUMBING DIAGRAM
PRELIMINARY
NONE
A
-
BBH
5-7-04



NOTES:

A — SUPPLIED BY CUSTOMER

B — ROUTE TO OUTSIDE

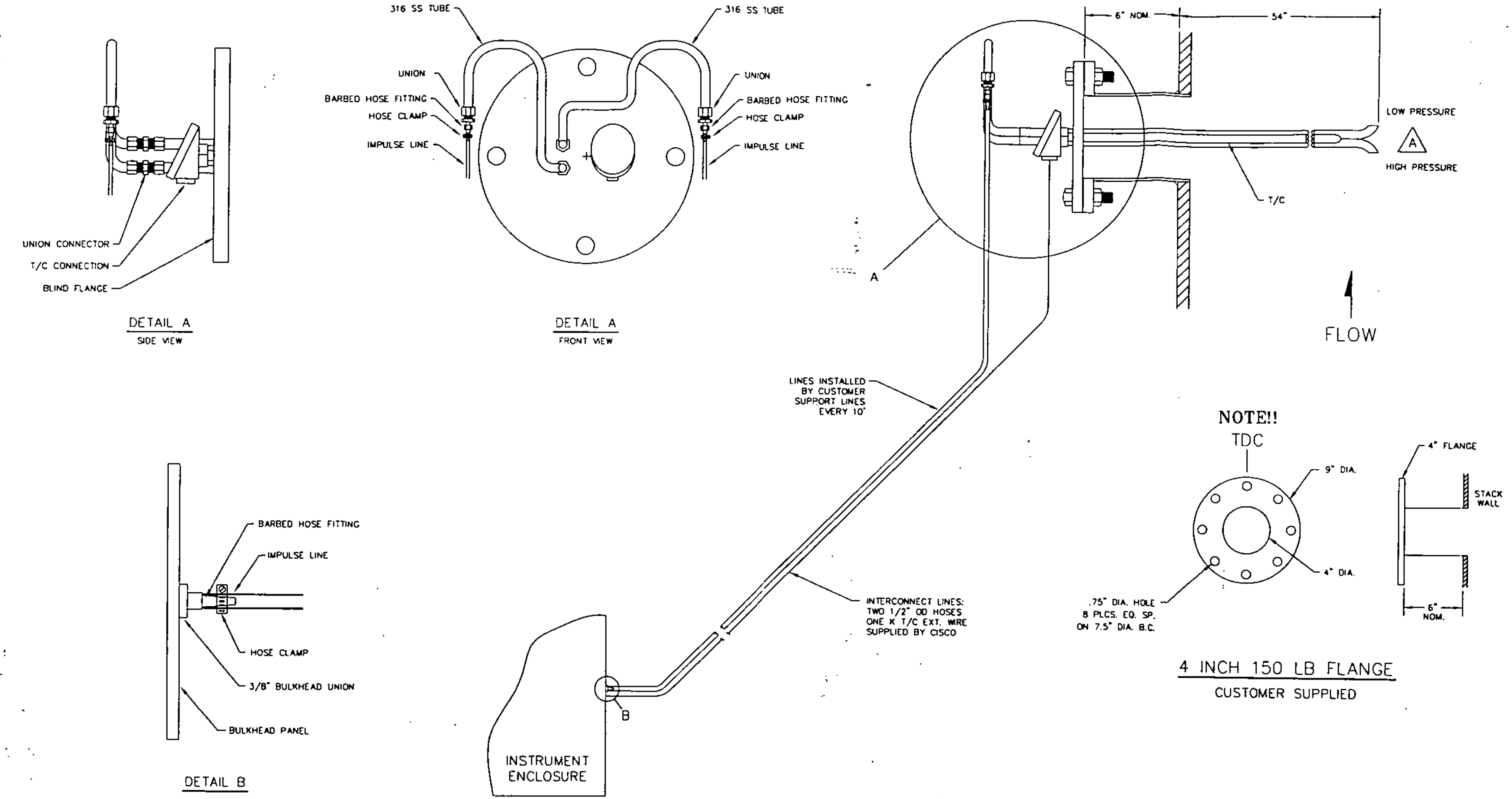
CISCO — CUSTOM INSTRUMENTATION SERVICES CORPORATION

CLEWISTON SUGAR MILL & REFINERY

ONE LINE DIAGRAM

SCALE	REVISION	REV DATE	DRAWN BY	DATE
NONE	A	-	BBH	5-1-04

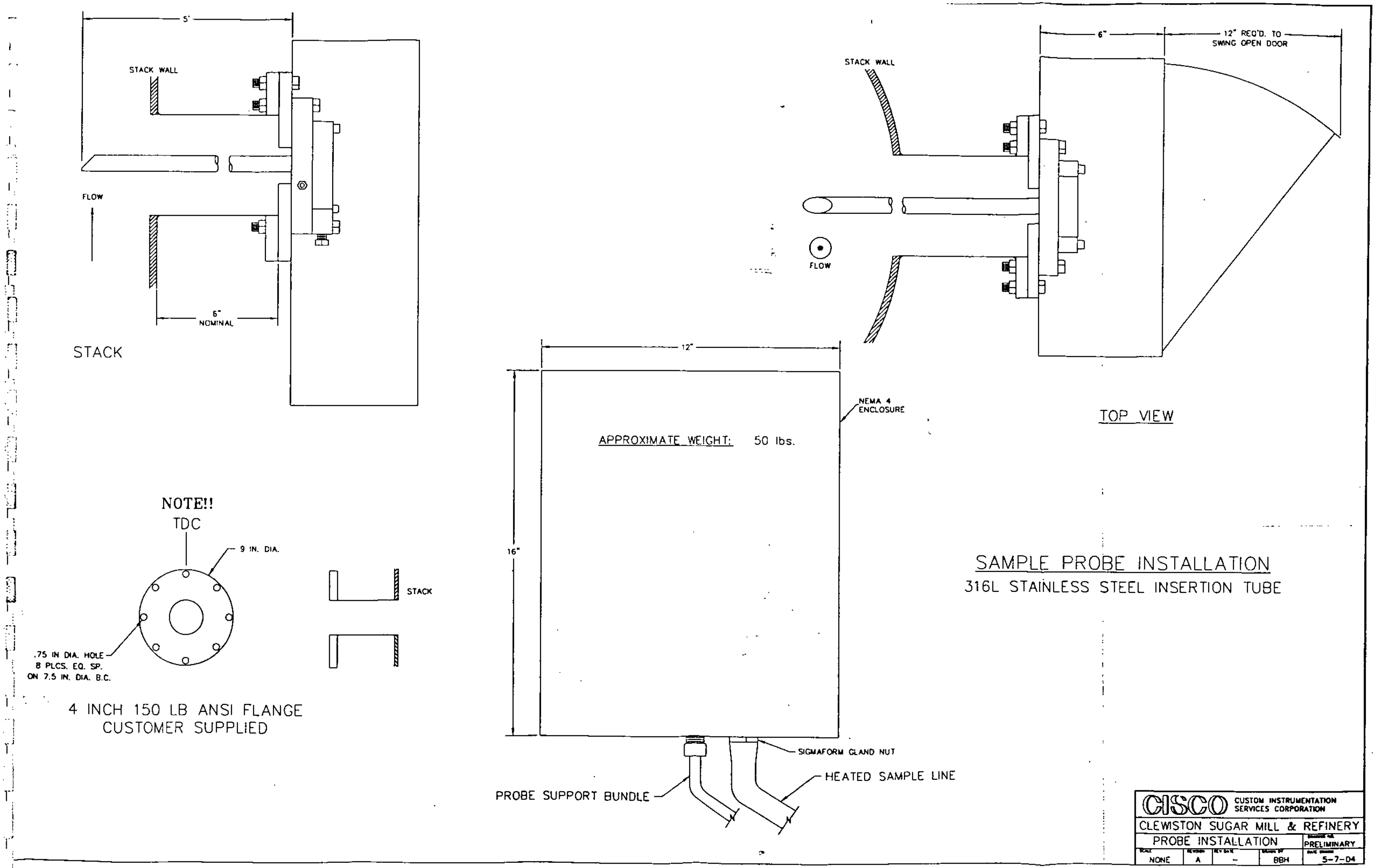
PRELIMINARY



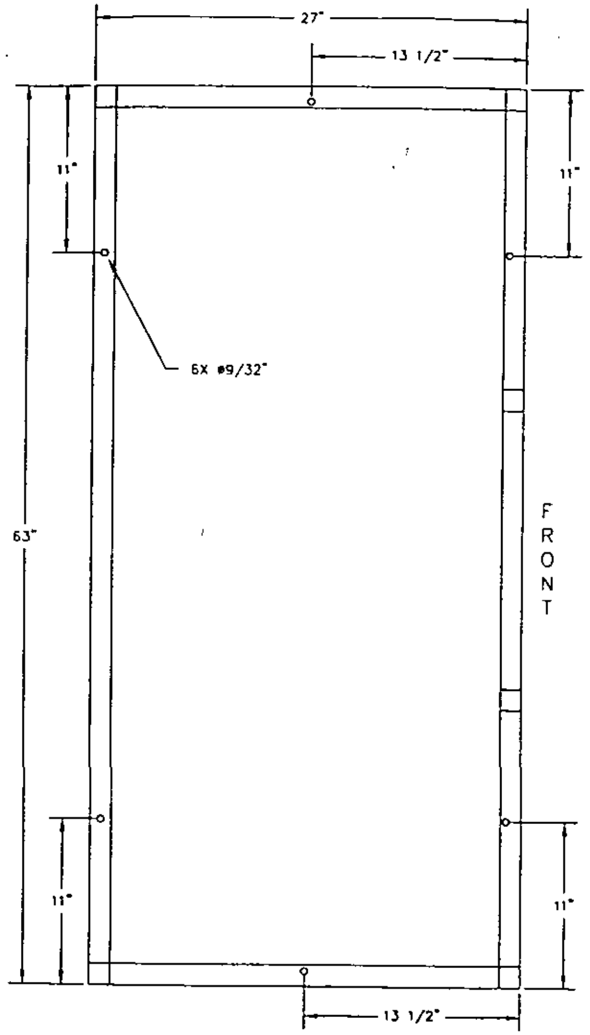
NOTES:

(A) FLOW PROBES TO BE MOUNTED SO THAT THEY DO NOT SLOPE UPWARD IN THE STACK

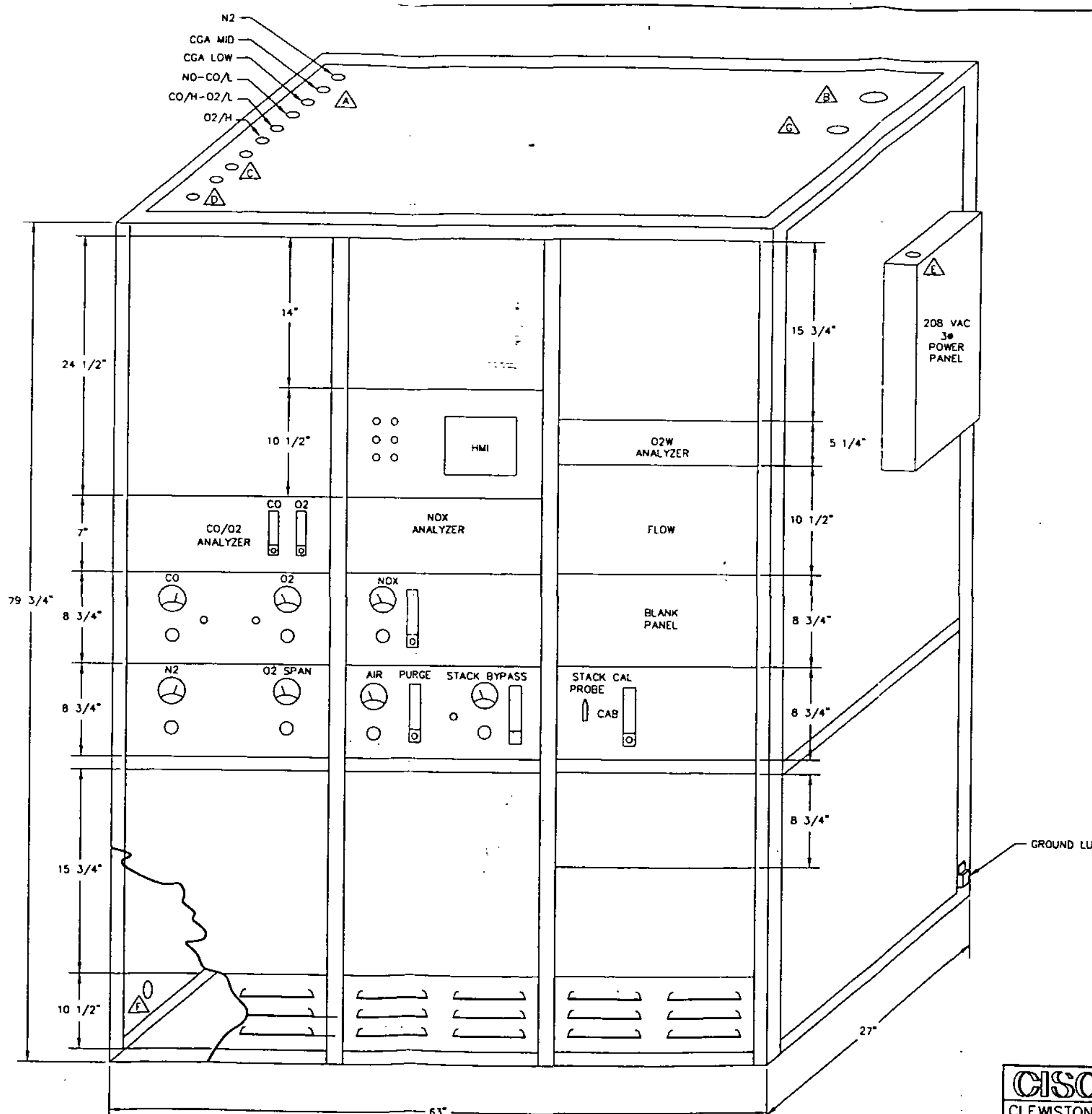
CISCO CUSTOM INSTRUMENTATION SERVICES CORPORATION					
CLEWISTON SUGAR MILL & REFINERY					
FLOW MONITOR INSTALL				PRELIMINARY	
NONE	A	-	BBH	5-7-04	



5'
STACK WALL
FLOW
6"
NOMINAL
STACK
6"
12" REQ'D. TO
SWING OPEN DOOR
STACK WALL
FLOW
TOP VIEW
12"
NEMA 4
ENCLOSURE
APPROXIMATE WEIGHT: 50 lbs.
16"
SIGMAFORM GLAND NUT
HEATED SAMPLE LINE
PROBE SUPPORT BUNDLE
NOTE!!
TDC
9 IN. DIA.
.75 IN DIA. HOLE
8 PLCS. EQ. SP.
ON 7.5 IN. DIA. B.C.
STACK
4 INCH 150 LB ANSI FLANGE
CUSTOMER SUPPLIED
SAMPLE PROBE INSTALLATION
316L STAINLESS STEEL INSERTION TUBE
CISCO
CUSTOM INSTRUMENTATION
SERVICES CORPORATION
CLEWISTON SUGAR MILL & REFINERY
PROBE INSTALLATION
PRELIMINARY
NONE
A
-
BBH
5-7-04



ANCHOR BOLT DETAIL



NOTES:

AMBIENT CONDITIONS REQUIREMENT 70° TO 85°F

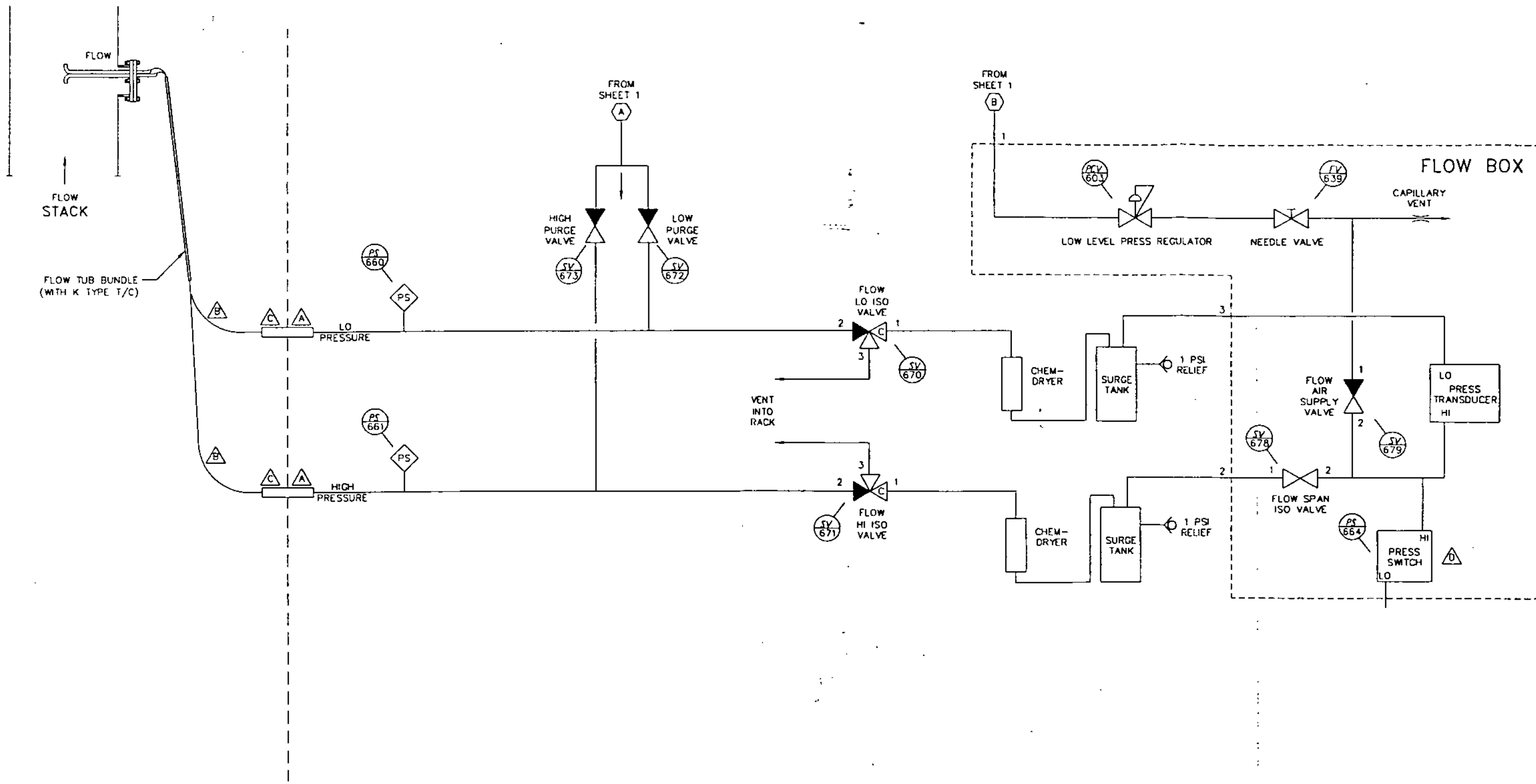
- A CAL GAS FITTINGS 1/4" TUBE BH (6)
- B HEATED SAMPLE LINE PENETRATIONS (1)
- C HRSG PROBE SUPPORT BUNDLE CONNECTIONS (3)
- D INSTRUMENT AIR 1/2" TUBE
- E POWER
- F 1 1/2" DRAIN PIPE
- G FLOW MONITOR SUPPORT PENETRATION

CISCO CUSTOM INSTRUMENTATION SERVICES CORPORATION

CLEWISTON SUGAR MILL & REFINERY

RACK LAYOUT — PRELIMINARY

SCALE	REVISION	REV DATE	DRAWN BY	DATE
NONE	A	–	BBH	5-7-04



NOTES:

A. 3/8" TUBE BULKHEAD FITTING

B. 1/2" RUBBER IMPULSE LINES (2)

C. 1/4" ID HOSE ADAPTER

D. ONCE THE FLOW SPAN PRESSURE IS REACHED DURING CALIBRATION, THE FLOW AIR SUPPLY VALVE CLOSES CAPTURING THE PRESSURE AND ACTIVATING THE FLOW HI SPAN READY.

CISCO CUSTOM INSTRUMENTATION SERVICES CORPORATION

CLEWISTON SUGAR MILL & REFINERY

PLUMBING DIAGRAM

PRELIMINARY

SCALE			DRAWN BY	DATE
NONE	A	-	BBH	5-7-04

APPENDIX B

DATA ACQUISITION AND HANDLING SYSTEM (DAHS) SPECIFICATIONS BY CISCO

DAHS SPECIFICATION

U.S. Sugar Corp: Boiler #8
Clewiston, Florida

October 2004
Rev. D

Custom Instrumentation Services Corporation

7325 SOUTH REVERE PARKWAY ❖ CENTENNIAL, COLORADO 80112
TEL: (303) 790-1000 FAX: (303) 790-7292

TABLE OF CONTENTS

1. DAHS SYSTEM OVERVIEW

Job Number:	20851	**System Number:**	10007180
Job Name:	US Sugar Clewiston Boiler #8	**Units:**	1
Location:	Clewiston, FL		
Regulations:	40CFR60, Subparts A, Db	**ORIS Code:**	N/A
Permit Number:	PSD–FL–333		
PLC Information:	Control Logix	**DARS PC Information:**	CeDAR
		Communication Type:	Ethernet
Analyzer Information:	NO_X: Rosemount 951C CO/O_2: Siemens 6E O_2(Wet): Ametek		

Description: The United States Sugar Corporation (USSC) operates the existing Clewiston sugar mill and refinery. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and passed through a series of presses to squeeze juice from the cane. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. Clewiston Boiler #8 will fire bagasse as the primary fuel Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Air pollution control equipment includes a wet cyclone/electrostatic precipitator (ESP) combination to remove particulate matter and a selective non-catalytic reduction system (SNCR) to reduce nitrogen oxides. Monitoring equipment will continuously monitor and record emissions of carbon monoxide and nitrogen oxides. The existing facility has no units subject to the acid rain provisions of the Clean Air Act.

CONTACT INFORMATION:

Company	Name	Title/Department	E-Mail	Phone	Fax
CiSCO	Donrich Ebuen	Project Engineer/ Engineering	debuen@ciscocems.com	303.790.7827x126	303.790.7292
CiSCO	Sarah Gray	Environmental Scientist/ Environmental	sgray@ciscocems.com	303.790.7827x144	303.790.7292
CiSCO	Brian Rezek	Programmer/ Software	bdrezek@ciscocems.com	303.790.7827x120	303.790.7292
CiSCO	Clif Peterson	PLC Programmer	cpeterson@ciscocems.com	303.790.7827x129	303.790.7292
McBurney	Steve Greene	Instrumentation, Control, Electrical Engineering	steveg@mcburney.com	770.925.7100x313	770.925.7400

QUESTIONS & COMMENTS:

1) Plant Signal – UREA Injection: CiSCO needs to know the percent NH_3 contained UREA solution. Also, what units will used for UREA injection?
   a) *CiSCO: The percent NH_3 contained in the UREA injection is required for calculation for Ammonia slip. However, the permit does not require the Ammonia slip to be calculated, the percent NH_3 is not needed.*
   b) *McBurney: Units and range for UREA → 0 –240 gph (email 11/16/04)*
2) Analog Output: Startups, Startup Duration, Shutdowns, Shutdown Duration, Malfunctions, Malfunction Duration, and Malfunction Emission are already being provided on the CEMS reports. Do you still require a analog signal for these parameters?
   a) *McBurney: Required for the site info. (Steve Greene 09/27/04)*
3) Please confirm how to determine "Boiler Startup" (please reference "Process Status Section"). The permit defines the desired temperature for the superheater steam temperature to be 500° F. Will the CEMS have an analog signal for this? The permit also references a 4 to 5 hour to reach this temperature. Do you want to use a timer for startup?
   a) *McBurney: Startup ends when 300,000 lb/hr Steam is attained (Increasing) (Steve Greene 09/27/04)*
4) Please confirm how to determine "Boiler Shutdown" (please reference "Process Status Section") The permit states "To initiate shutdown, the bagasse fuel feed is terminated." Will the CEMS be provided a signal for this determination?
   a) *Shutdown begins when steam drops below 300,000 lb/hr. (Decreasing) (Steve Greene 09/27/04)*
5) Bagasse – CiSCO will need a GCV value and quantity of bagasse burned for emission calculations. Also, you can provide a Heat Input value (Analog signal) or a constant User Setting for Heat Input.
   a) *See Question 19*
6) CiSCO needs additional clarification concerning "Block Average" See Permit pg. 24 (12.b.4).
   a) *Golder Associates Response: The permit limits the NOx emissions during periods of SSM to 0.28 lb/mmBtu for periods of the SSM. Each period of the SSM is a block of time and the average for that time is the block average. (email 10/21/04)*
7) Determination of Heat Input Based on Steam Pressure, Temperature, and Production Rate references a computer algorithm or look-up table to determine enthalpy of the steam and feedwater (Btu/lb). Please provide the algorithm or look-up table.
8) Process Status: Define Malfunction. Is it a CEMS malfunction, or is it a site input?
   a) *McBurney: CEM malfunction – (Steve Greene 09/27/04)*
9) Reports: Define "Number of hours of quality assurance calibration"?
   a) *Golder Associates Response: The quarterly report requires the reporting of the amount of time the CEM was in calibration mode and not sampling from the stack. (email 10/21/04)*
10) Equations: Stack Gas Flow Rate (p.11), please verify equation. Not sure why we divide by 100.
   a) *Golder Associates Response: In the equation: SCFM = ACFM x (528/T) x (1-%M)/100, we divide by 100 because the moisture content is in % not decimal form. I.e. 30% as apposed to 0.30.*
   b) *CiSCO Response: Agreed, however CiSCO believes that the divide by 100 should be contained inside the parentheses as appose to outside. SCFM = ACFM x (528/T) x (1-%M/100)*
   c) *McBurney: SCFM = ACFM x (528/T) x (1-(%M/100)) (email 10/29/04)*
11) Process Status: Will the site be providing a "Malfunction" Signal (p.12)?
12) Reports: Customer defined reports – Do these reports need to be in a "Excel" format, our standard is the create these reports in "Word" format.
   a) *McBurney: "Word" format will be sufficient. (Email 10/29/04)*

13) Golder Associates Comments: Section 4: Equations – Add averaging equations referenced in permit.
    a) *CiSCO – Added to Section 4.*
14) Golder Associates Comments: Section 6. Data Validation, Averaging and Summation: Need to include NOx block average during periods of SSM. Permit Condition 12 b. 4) "for the period of excluded data, NOx emissions shall not exceed 0.29 lb/mmBtu based on block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction. (Email 10/21/04)
    a) *CiSCO – Added to Section 6.*
15) Golder Associates Comments: Section 8. Reports: In addition to the Quarterly report US Sugar has requested that the system produce a Annual Operating Report. This report will summarize annual average data that US Sugar will utilized to complete FDEP's Annual Operating Report requirement. See attached for a table that summarizes the data to be produced in the quarterly and annual reports. (Email 10/21/04)
    a) *CiSCO – Added to Section 8.*
16) Reports: Customer defined reports – How is "Crop Season" defined? (Report Items 19& 20)
    a) *McBurney – Crop season is defined as the operation during the period from October 1 through April 30th. (email 10/29/04)*
17) Reports: Customer defined reports – How is days per week defined? Is this Sun-Sat, Mon-Sun, or other method? (Item 2)
    a) *McBurney – Sunday – Saturday (email 10/29/04)*
18) Reports: Customer defined reports – What is the definition of Percent Operation? (Items 5, 7, 9, & 11)
    a) *McBurney – (Hours of boiler operation in Dec, Jan, Feb) / (total hours boiler operated in year) x 100, similar for other quarters. (email 10/29/04)*
19) Reports: Customer defined reports – Bagasse is not entered into the CEMS, we need an entry for this if we are to report this on this report (Item 12)
    a) *McBurney – The amount of bagasse fired will be back calculated from the steam output as follows (email 10/29/04):*
        i) *Total Boiler heat input, MMBtu/hr = Bagasse heat input, MMBtu/hr + Fuel Oil heat input, MMBtu/hr*
        ii) *Therefore:*
            (1) *Bagasse heat input, MMBtu/hr = Total Boiler heat input, MMBtu/hr – Fuel Oil heat input, MMBtu/hr*
        iii) *Where:*
            (1) *Total Boiler heat input (MMBtu/hr) calculated base on the enthalpy of steam and feedwater as defined in DAHS Specification.*
            (2) *Fuel Oil heat input, MMBtu/hr = (Gallons fuel oil / hour) x (136,000 Btu/gal) x (1MMBtu/1000000Btu)*
            (3) *Bagasse hourly fire rate, lb/hr = (Bagasse heat input, MMBtu/hr) / (Heating value of Bagasse, MMBtu/lb)*
        iv) *Heating value of Bagasse will be determined quarterly and provided to CEM system for use in calculation. The approximate higher heating value of bagasse as fire 3,600 btu/lb.*
20) Reports: Customer defined reports – What is Petroleum Contaminated Soil? (Item 14)
    a) *McBurney – US Sugar currently burns a limited amount of solid fuel that can contain bagasse, oil, lime, and other constituents in existing boilers. If burned in Boiler 8, the amount burned will be provided by US Sugar personnel. The DAHS have an input to keep track of this fuel use as provided by US Sugar operators. (email 10/29/04)*
21) Reports: Customer defined reports – What is "On spec" used oil (Item 15)
    a) *McBurney – "On Spec" oil is used oil that meets specific limitations of content of arsenic, cadmium, chromium, lead, flash point, and halogens. If "On Spec" fuel oil is burned in boiler 8,*

the amount burned will be provided by US Sugar personnel. The DAHS should have an input to keep track of the "on Spec" fuel use as provided by US Sugar operators. (email 10/29/04)

22) Reports: Customer defined reports – How do we separate Hours of Operation/Heat Input of Oil vs Bagasse? Can both be burned at once (Items 17/18 AOR & 4/5 Fee)
    a) *McBurney – Remove item 17 and 18 from the AOR reporting. Total hours of operation of the boiler will be sufficient information to complet the annual operating report. (email 10/29/04)*
23) DAHS Config: Added to this project is a DAHS feature to indicate at what level the site should be running in order to ensure that the site is not exceeding their limits. However, a majority of the limits are based on a 12-month rolling number. CiSCO needs clarification on what interval do we need to be looking at: Yearly, monthly, daily, 3 hour average, hourly, etc. The larger the interval the more difficult it is for the prediciton value. If you need further information concerning this, please contact Walt Bastorn (Director of Software) ext. 112.

REVISION NOTES:

- Revision "A" – 08/25/04 by Donrich Ebuen
- Revision "B" – 08/27/04 CiSCO Review: Software & Engineering
- Revision "C" – 09/09/04 CiSCO Review: Software & Engineering
- Revision "D" – 10/22/04 Customer Comments – Email 10/21/04 from Steve Greene (McBurney)

2. DAHS SIGNALS

PLC Signals

Analog Input				
Parameter	**Range**	**Units**	**Signal**	**Source**
Stack O_2 (Dry)	0 – 25	%	4 – 20 mA	Analyzer
Stack O_2 (Wet)	0 – 25	%	4 – 20 mA	Analyzer
Stack NO_X	0 – 250	ppm	4 – 20 mA	Analyzer
Stack CO	0 – 1,000/10,000	ppm	4 – 20 mA	Analyzer
Stack Temperature	0 – 800	° C	4 – 20 mA	Flow Box
Stack Pressure	0 – 2	In H_2O	4 – 20 mA	Flow Box
Rack Temperature	0 – 150	° F	4 – 20 mA	CEMS
SCNR				
UREA Injection	0 – 240	gph	4 – 20 mA	Plant Signal
Steam Parameters				
Steam Temp	400 – 1,000	° F		Via Ethernet
Steam Pressure	500 – 1,000	psig		Via Ethernet
Steam Production Rate	0 – 600	klb/hr		Via Ethernet
Feed water Temp	50 – 500	° F		Via Ethernet
Feed water Pressure	0 – 1,500	psig		Via Ethernet
Fuel Oil Parameters				
Fuel Oil Flow	0 – 3,600	gph		Via Ethernet
ESP Monitoring #1				
Secondary Voltage	0 – 200	kVolts		Via Ethernet
Secondary Current	0 – 5,000	mADC		Via Ethernet
Minimum Secondary Power Input	0 – 9,999	KWx10		Via Ethernet
ESP Monitoring #2				
Secondary Voltage	0 – 200	kVolts		Via Ethernet
Secondary Current	0 – 5,000	mADC		Via Ethernet
Minimum Secondary Power Input	0 – 9,999	KWx10		Via Ethernet
ESP Monitoring #3				Source
Secondary Voltage	0 – 200	kVolts		Via Ethernet
Secondary Current	0 – 5,000	mADC		Via Ethernet
Minimum Secondary Power Input	0 – 9,999	KWx10		Via Ethernet

Analog Input				
Parameter	**Range**	**Units**	**Signal**	**Source**
ESP Monitoring #4				
Secondary Voltage	0 – 200	kVolts		Ethernet
Secondary Current	0 – 5,000	mADC		Ethernet
Minimum Secondary Power Input	0 – 9999	KWx10		Ethernet
ESP Monitoring #5				
Secondary Voltage	0 – 200	kVolts		Ethernet
Secondary Current	0 – 5,000	mADC		Ethernet
Minimum Secondary Power Input	0 – 9,999	KWx10		Ethernet
Wet Cyclone #1				
Water Flow Rate	0 – 45	kgph		Ethernet
Pressure Drop	0 – 10	in H2O		Ethernet
Wet Cyclone #2				
Water Flow Rate	0 – 45	kgph		Ethernet
Pressure Drop	0 – 10	in H2O		Ethernet

Analog Output				
Parameter	**Range**	**Units**	**Signal**	**Source**
CO	0 – 1,000 / 0 –10,000	ppmvd		Ethernet
CO		lb/MMBtu		Ethernet
CO		tons/yr		Ethernet
NO_X	0 – 250	ppmvd	4 – 20 mA	Ethernet/ TB1X
NO_X		lb/hr		Ethernet
NO_X		lb/MMBTU		Ethernet
O_2	0 – 25	%		Ethernet
Stack Gas Flow Rate		ACFM		Ethernet
Stack Gas Temperature		° F		Ethernet
Stack Gas Moisture		%		Ethernet
Startups		Qty (#)		Ethernet
Startup Duration		Min/ event		Ethernet
Shutdowns		Qty (#)		Ethernet
Shutdown Duration		Min/ event		Ethernet
Malfunctions		Qty (#)		Ethernet
Malfunction Duration		Min/ event		Ethernet
Malfunction Emission		lb/event		Ethernet
CEMS Availability	0 – 100	%		Ethernet

Digital Input		
Parameter	**State Logic**	**Source**
Flame On	Flame On = 1	Plant Signal
Power Fail	(24 VDC Off =Alarm)	CEMS
Probe Power	Power On (Closed=Alarm)	CEMS
Shelter High Temp	Temp <= 105° F (Open=Alarm)	CEMS
Shelter Low Temp	Temp < 60° F (Closed=Alarm)	CEMS
Instrument Air Pressure	Pressure < 70 psi (Closed=Alarm)	CEMS
(Stack) HSL Temp	Temp < 350° F (Closed=Alarm)	CEMS
(Stack) Water in sample	Water in sample (Closed=Alarm)	CEMS
(Stack) High Vacuum	7 to 8 in Hg Max (Closed=Alarm)	CEMS
Bath Temp	Temp < 40° F (Open=Alarm)	CEMS
Stack Cal Flow	Flow >5 liter/min (Open=Alarm)	CEMS
Stack N_2 Pressure	40 psig Min (Closed=Alarm)	CEMS
Stack CO Analyzer not ready	When ready (Open=Not Ready)	CEMS
Stack O_2 Analyzer not ready	When ready (Open=Not Ready)	CEMS
Smoke	Smoke in shelter (Closed=Alarm)	CEMS

Digital Output	
Parameter	**State Logic**
System Fault	Fault = 0
NOX Valid	High = 1
Stack CO Range	High = 1
Smoke Alarm	Alarm = 0
Stack Sample Pump	Pump On = 1
Loss of Communication	Comm Loss = 0
Backflush Valve	On = 1
Zero Valve	On = 1
NO/CO/L Span Valve	On = 1
CO/H – O_2/L Span Valve	On = 1
O_2/H Span Valve	On = 1
CGA Low Valve	On = 1
CGA Mid Valve	On = 1

3. PERMIT LIMITS

Measured Parameter Limits

Unit(s)	Parameter	Limit	Duration	Notes
Boiler #8	CO, lb/MMBtu	0.38	Consecutive 12 months excluding periods of startup, shutdown, and malfunction	Pg. 23
Boiler #8	CO,Tons/yr	1285	Consecutive 12 months including periods of startup, shutdown, and malfunction	Pg. 24
Boiler #8	NO_X, lb/MMBtu	0.14	30 – Day rolling average excluding startup, shutdown, and malfunction	Pg. 24
Boilter #8	NO_X, lb/MMBtu	0.28	Block average for the periods of excluded data (startup, shutdown, and malfunction)	Pg. 24

Emission Factors and Limits

NOTE: The default values for GCV, F-Factor used in calculations are:

Oil

- GCV = 134,000 Btu/gal
- F-Factor = 9190 dscf/mmBtu
- Fuel Density = 7.1 lb/gal

OPERATING LIMITS

- Authorized Fuels: Boiler 8 shall fire bagasse as the primary fuel and distillate oil as a restricted alternate fuel for startup and supplemental uses.
- Boiler 8 shall not exceed the following operational levels:
    - 12,000,000 pounds of steam per day.
    - $3.6135 \times 10^{+09}$ pounds of steam per consecutive 12 months
    - 99,864 gallons of distillate oil per day
    - 6,073,600 gallons of distillate oil per consecutive 12 months

4. EQUATIONS

Correction of Pollutant Concentrations to Desired Percent O_2

To calculate emission concentration corrected to a particular Oxygen concentration. $$C_{adj} = C_d \times \frac{20.9 - XO_2}{20.9 - \%O_2}$$ Units: ppmvd Reference: 40CFR60 Appendix A, Method 20, Eq. 20-4 CiSCO Formula ID 0010	• C_{adj} = Emission concentration corrected to C percent O_2 • C_d = Emission concentration measured dry, ppmvd • X_{O2} = Desired O_2% correction value. Typically 15% for turbines and 3% or 7% for boilers • %O_2 = Oxygen percentage in flue gas, for 0 < O2 % < 20.0 %

Volumetric Stack Flow From Stack Gas Velocity

To calculate dry standard volumetric stack flow using stack gas velocity in ft/sec $$Q_{sd} = 3600 \times (1 - B_{ws}) \times V_s \times A \times \left[\frac{T_{std}}{T_s} \times \frac{P_s}{P_{std}}\right]$$ Units: dscf/hr Reference: 40CFR60 Appendix A, Method 2, Eq. 2-10 To calculate stack gas velocity using a delta pressure meter $$V_s = K_p \times C_p \times \sqrt{\Delta P} \times \sqrt{\frac{T_s}{P_s \times MW_s}}$$ Units: ft/sec Reference: 40CFR60 Appendix A, Method 2, Eq. 2-9 To calculate wet gas molecular weight from dry gas density. $$MW_s = MW_d \times (1 - B_{ws}) + (18 \times B_{ws})$$ Reference: 40CFR60 Appendix A, Method 2, Eq. 2-5 CiSCO Formula ID 0060	• Q_{sd} = Dry standard volumetric stack flow, dscf/hr • B_{ws} = Proportion by volume of H_2O in stack gas (%H_2O/100) ($0 \le B_{ws} \le 1$) (constant, measured using Formula 0130 or Formula 0180, or calculated using psychometric chart or saturated vapor pressure tables -- see 40CFR60 Appendix A, Method 4 sect 1.2) • V_s = Average Stack Velocity, ft/sec • A = Stack Area, square feet • T_s = Stack Absolute Temperature, °R = °F + 460 • T_{std} = Standard Absolute Temperature, 528 °R • P_s = Stack Pressure absolute (barometric pressure + stack static pressure), inches Hg • P_{std} = Standard absolute pressure, 29.92 inches Hg • K_p = Flow Monitor Constant, 85.49 ft/sec[(lb/lb-mol)(in. Hg)/((°R)(in. H2O))]^0.5 • C_p = Flow Monitor Coefficient (Typical - 84 S-pitot Tube: 1 on Air monitor) • ΔP = Delta Pressure or velocity head of stack gas, inches H_2O • MW_s = Molecular weight of wet stack gas • MW_d = Molecular weight of dry stack gas (29.0 lb/lb-mol if air or 29.0 < MW_d < 30 lb/lb-mol if stack gas)

Mass Emissions Rate From Flow Monitor

To calculate mass emissions rate in lb/hr when a stack flow monitor is used $$M_i = 1.0\mathrm{E}-6 \times C_d \times \frac{(Q_{sd} \times MW_i)}{385.3}$$ Units: lb/hr Reference: CISCO Formula ID 0090	• M_i = Mass emission rate of pollutant i, lb/hr • 1.0E-6 = conversion for ppm • C_d = Emission concentration of pollutant I, ppmvd • Q_{sd} = Dry standard volumetric stack flow, dscf/hr • MW_i = Molecular weight of pollutant I, lb/lb-mol (SO_2 64 lb/lb-mol, NO_2 46 lb/lb-mol, CO 28 lb/lbmol, NH_3 17 lb/lb-mol) • 385.3 = Conversion constant, dscf/lb-mol (use 379.0 for South Coast AQMD)

Percent Moisture Calculation

Calculate moisture content using a wet oxygen monitor and a dry oxygen monitor. $$\%H_2O = \left[\frac{O_2d - O_2w}{O_2d}\right] \times 100$$ Reference: EDR Version 2.1, Table 16, Code M-1 CISCO Formula ID 0130	• $\%H_20$ = Percent moisture • O_2w = Oxygen diluent concentration (percent of effluent gas, wet basis) • O_2d = Oxygen diluent concentration (percent of effluent gas, dry basis)

Annual Average Emission Rate lb/mmBtu

Use the following equation to calculate the annual average emission rate for each calendar year. $$E_a = \sum_{i=1}^{m} \frac{E_i}{m}$$ Units: lb/mmBtu Reference: 40CFR75 Appendix F 3.4 **CISCO Formula ID F-10**	• E_a = Average NO_x or CO emission rate for the calendar year, lb/mmBtu. • E_i = Average hourly NO_x or CO emission rate during unit operation, lb/mmBtu. • m = Number of hours for which E_i is available in the calendar year.

Heat Input

Use the following equation to calculate the Heat Input Based on Steam Pressure, Temperature, and Production Rate Net Enthalpy (Btu/lb) = Enthalpy of Steam – Enthalpy of Feedwater Heat Content of Steam = Net Enthalpy (Btu/lb) x Steam Production Rate (lb/hr) Heat Input to Boiler (MMBtu/hr) = heat content of Steam/ Efficiency of Boiler, 62% Units: MMBtu/Hr Reference: US Sugar RFQ	• Steam Pressure, psia • Steam Temperature, deg F • Steam Production, lb/hr • Feedwater temperature, deg F • Feedwater pressure, psia

Stack Gas Flow Rate

Use the following equation to calculate Stack Gas Flow Rate SCFMD = ACFM x (528/T) x (1-(%M/100)) Convert to SCFHD Units: SCFHD Reference: US Sugar RFQ	• %M → Stack gas moisture fraction, % • T → Stack Gas Temperature Monitor, deg F • Flow Monitor, ACFM

1-Hour Average

Use the following equation to calculate the Hourly emission average. $E_{hr} = \sum_{i=1}^{n} \frac{E_i}{n}$	• E_{hr} = Hourly average (NO_x or CO) emission rate, lb/mmBtu. • E_i = Valid Minute Reading (NO_x or CO) emission rate, lb/mmBtu. • n = Number of valid minute readings during given hour.

24-Hour Average

Use the following equation to calculate the 24-Hour emission average. $$E_{24hr} = \sum_{i=1}^{n} \frac{E_i}{n}$$	• E_{24hr} = 24-Hour block average CO emission rate, (lb/mmBtu or lbs/day) beginning a midnight of each operating day. • E_i = One Hour average CO emission rate, (lb/mmBtu or lbs/day). • n = Number of valid 1-hour readings during given 24-Hour block.

30-Day Average

Use the following equation to calculate the 30-Day emission average. $$E_{30day} = \sum_{i=1}^{n} \frac{E_i}{n}$$	• E_{30day} = 30-Day rolling average NO_x emission rate, lb/mmBtu. • E_i = Hourly average NO_x emission rate, lb/mmBtu. • n = Number of hours for 30 successive boiler operating days when fuel was combusted

Annual Average

Use the following equation to calculate the Annual emission average. $$E_{annual} = \sum_{i=1}^{n} \frac{E_i}{n}$$	• E_q = 12-month rolling total of CO for the 12-month . • E_i = Daily CO mass emission rates (pounds per day) for a the 12-month period. • n = Number of days for the 12-month period

5. PROCESS STATUS AND EMISSION MONITORING

PROCESS STATUS

Process Codes (PC) describes the operating condition of the unit in relation to permit exemptions and conditions. They are different from monitor codes, which define the status and validity of the data associated with each individual parameter. In general the PLC uses the plant information such as fuel flow, electric load generated and flame on signal to generate a process code. Each unit has their own process code.

Following are the process codes used for this project and how they are defined:

1) PC 01 (Fuel Transfer)
   -

2) PC 03 (Startup)
   - ***Begin Startup*** – "Flame On" Signal is on.
   - ***End Startup*** – ~~From Permit: Timer: 5 hours after "Flame On" signal is high or Steam temperature is 500° F. From RFQ:~~ Startup ends when 300,000 lb/hr Steam is attained (Increasing)

3) PC 04 (Shutdown)
   - ***Begin Shutdown*** – ~~From Permit: Bagasse fuel feed is terminated. (Customer to provide signal).~~ From RFQ: Shutdown begins when steam drops below 300,000 lb/hr. (Decreasing)
   - ***End Shutdown*** – "Flame On" signal is off.

4) PC 07 (Equipment Cleaning)
   -

5) PC 08 (Normal Operation)
   Process code 08 is used for all periods of aux boiler being offline and normal operating time.

Notes from RFQ:
Boiler Status

Determination of Status of Boiler as Follows:
A) Steam Production Rate > 300,000 lb/hr
B) Steam Production Rate is < 300,000 lb/hr and increasing
C) Steam Production Rate is < 300,000 lb/hr and decreasing
D) Malfunction Yes or No

CEM Boiler status logged with time as follows:
A) Normal Operation if A = Yes, B = No, C = No, and D = No
B) Startup if A = No, B = Yes, C = No, and D = No
C) Shutdown if A = No, B = No, C = Yes, and D = No
D) Malfunction if D = Yes

6. DATA VALIDATION, AVERAGING AND SUMMATION

40CFR60 Minute
Two 'VALID' 10-second reads are required for a valid minute average. Two 'DOWN' 10 second reads constitutes a down minute average.

40CFR60 Block Hour
Averaging will be done based on the NORMAL quadrant averaging rules. A quadrant must have at least one valid reading to be considered a valid quadrant. <u>Four quadrants (*Permit defines Two*) must be valid for a valid hour average</u>. <u>If there is maintenance or calibration done in the hour then only two quadrants are required for a valid hour</u>.

40CFR60 Block Day
Averaging will include all valid 40CFR60 hours for the previous 24-hour period. The average will be updated at the end of the day. For further details, please consult 40CFR60.49a.

40CFR60 Block Month
Averaging will include all valid 40CFR60 days for the previous 1-month period. The average will be updated at the end of the month. For further details, please consult 40CFR60.49b.3(d).

40CFR60 Rolling 12 Month
Averaging will include all valid 40CFR60 months for the previous 12-month period. The average will be updated at the end of the month.

Permit Defined Averages

1-Hour Averages (CO and NO_X)
1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of "lb/MMBtu"

24-Hour Averages (CO)
Each 24-hour block shall begin at midnight of each operating day and shall be determined by averaging 24 consecutive 1-hour averages for each operating day. If the boiler operates less than 24 hours during the block, the 24-hour average shall be determined by averaging the available valid 1-hour block averages for actual boiler operation. Final results shall be recorded in terms of "lb/MMBtu" and "pounds per day".

30-Day Averages (NO_X)
The 30-day rolling average shall be determined by averaging all 1-hour averages for 30 successive boiler operating days. A boiler operating day begins and ends at midnight of each day and includes any day that fuel is combusted. Final results shall be recorded in terms of "lb/MMBtu".

Annual Averages (CO)
The 12-month rolling total shall be determined by summing the daily CO mass emission rates (pounds per day) for the 12-month period. The result shall be reported in terms of "tons per consecutive 12 months".

Excess Emissions (NO_X)
For the period of excluded data, NO_X emissions shall not exceed 0.28 lb/MMBtu based on a block average of the excluded CEMS data for the period identified as startup, shutdown, or malfunction.

MONITOR CODES

Description

Monitor codes indicate the validity of the associated values. Monitor codes (00) & (38) are codes that indicate valid data. All other monitor codes represent invalid data and some indication of the cause of invalidation.

Note: *Monitor codes are used to represent data validity and are not to be confused with Process Codes that are used to indicate a plant process status.*

MC	Description	Validity
00	Normal (valid)	VALID
11	Excess Primary Analyzer Drift (a pollutant analyzer is out-of-control)	INVALID
12	Excess Ancillary Analyzer Drift (a diluent analyzer is out-of-control)	INVALID
13	Process Down	DOWN
14	Calibration	INVALID
15	Preventative Maintenance (MCs 15 and 20 are interchangeable, except in PA)	INVALID
16	Primary Analyzer Malfunction (malfunction of a pollutant analyzer)	INVALID
17	Ancillary Analyzer Malfunction (malfunction of a diluent analyzer)	INVALID
18	DAHS Malfunction (also used as the default code for invalid values)	INVALID
19	Sample Handling System Malfunction (dryer fault, etc.)	INVALID
20	Corrective Maintenance (MCs 15 and 20 are interchangeable, except in PA)	INVALID
21	Other	INVALID
22	I/O Communications Problem	INVALID
23	Process Down and Sample Point Not Selected (this MC is down and applies to time share systems)	DOWN
25	Backflush	INVALID
26	Value is calculated or derived from substituted data	VALID
27	ODBC Data Not Available (data missing in an external database)	INVALID
28	Formula Input Value Out-Of-Range (and invalid)	INVALID
29	Process Down And Calibration (this MC is down)	DOWN
30	Sample Point Not Selected (used for timeshare systems)	INVALID
31	Value Out-Of-Range (and invalid)	INVALID
32	Value Out-Of-Range And Down (this MC is down)	DOWN
33	Data Not QA (used when 26 hours have passed without a calibration check)	INVALID
34	Not Sufficient Data (used when there is insufficient data to create an average, but creating an invalid MC would be difficult or irrelevant; example: subpart Da and Db 30-operating-day averages)	INVALID
37	Invalid Data (invalid data generated by PLC or other non-CeDAR source)	INVALID
38	Valid Data (valid data generated by PLC or other non-CeDAR source)	VALID
39	Down Data (down data generated by PLC or other non-CeDAR source)	DOWN
40	Substituted Data: average of hour before and hour after	VALID
41	Substituted Data: average of X hours before and X hours after, where the missing data period is X hours	VALID
42	Substituted Data: max value in the previous 30 calendar days	VALID

MC	Description	Validity
43	Substituted Data: max value in the previous 365 calendar days	VALID
44	Substituted Data: max value since CEMS certification date	VALID
45	Substituted Data: other method	VALID

7. CALIBRATIONS AND LINEARITY/CGA TESTS

Daily Calibrations

Unit(s)	Analyzer Range	Regulation
Boiler #8	STK NO_X Single Range	40CFR60
Boiler #8	STK CO Low and High Range	40CFR60
Boiler #8	STK O_2 Single Range	40CFR60

Quarterly Linearity/CGA Tests

Unit(s)	Points/Parameters	Reg/Type	Gas Levels*	# Runs
	STK NO_X Single Range	40CFR60 CGA	L,M	3
	STK CO Low Range	40CFR60 CGA	L,M	3
	STK CO High Range	40CFR60 CGA	L,M	3
	STK O2 Single Range	40CFR60 CGA	L,M	3

* Gas Levels – Zero(Z), Low(L), Mid(M)

8. REPORTS

Following reports are provided for this project:

For each unit

- Hourly Emissions and Operations Report – displays minute data in the hour with hourly average and/or total values at the bottom of the report.
- Daily Emissions and Operations Report – displays hourly data for the day with daily average and/or total values at the bottom of the report.
- Monthly Emissions and Operations Report – displays daily data for the month with monthly average and/or total values at the bottom of the report. For the parameters with 12-month rolling total (facility) limit, a 12-month rolling total is also reported.
- Startup and Shutdown Episodes Report - displays durations of all the startup and shutdown in the time period selected.
- Calibration Report (Standard CiSCO format) - automatically printed out after calibration is complete.
- Downtime Report (Standard CiSCO format) – displays the downtime of the parameter with hourly emission limit. For each emission parameter that has a limit and based on a analyzer reading, the monitor code of the data is checked every hour for validity. If the monitor code is invalid, the downtime occurrence for that parameter is recorded in the database. The report will display the total number of inoperative hours and percent availability for the specified emission parameter.
- Excess Emission Report (Standard CiSCO format) – displays the excess emissions of the parameter selected. The report will display the reason and duration for each exceedence. The user using the Database Editor can enter reason codes. If no reason code is entered, the entry on the report will be blank. A summary line will describe the total time of exceedence, the total operating time, and total operating time with exceedence for the time frame entered.

Permit Defined Reports

- Monthly Operations Summary – By the tenth calendar day of each month, the permittee shall record the following for each fuel in a electronic log for the previous month of operation: Hours of operation, distillate oil consumption, pounds of steam per month, and the updated 12-month rolling totals for each of these parameters.
- Quarterly CO and NO_X Emissions Report – Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Aurthority summarizing CO and NO_X emissions including periods of startups, shutdowns, malfunctions, and CEMS systems monitor availability for the previous quarter. If CO or NO_X CEMS data is excluded from a compliance determination during the quarter due to a malfunction, ther permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction.

Customer Defined Reports

- Quarterly Report – At the end of each quarter the CEM data acquisition system (DAS) must produce the following summary of information for preparation of the quarterly report

1	Calendar quarter identification 1, 2, 3, or 4		______	Qtr
2	Hours operation in Calendar Quarter		______	Hrs/Qtr
3	Monitor Manufacture	CO	______	Mfg Name
		NOX	______	Mfg Name
		O2	______	Mfg Name
4	Monitor Model Number	CO	______	Model No.
		NOX	______	Model No.
		O2	______	Model No.
5	Date of last certification or audit		______	Date
6	CO CEM Emission Standards, Permit Limit	0.38 lb/mmBtu –12 month rolling		
7	NOX CEM Emission Standards, Permit Limit	1,285 tons – 12 consecutive months		

Excess Emissions

8	Number of startup/shutdown hours in quarter		______	Hrs
9	Number of hours of control equipment problems		______	Hrs
10	Number of hours of process problems		______	Hrs
11	Number of hours of other known problems		______	Hrs
12	Number of hours of unknown problems		______	Hrs
13	Total hours of excess emissions		______	Hrs
14	Percent time of total hours of excess emissions = (total hours of excess)/(total hours of operating time)*100%		______	%

CEMS Operation

15	Number of hours of CEM monitor equipment malfunctions		______	
		CO	______	Hrs
		NOX	______	Hrs
		O2	______	Hrs
16	Number Hours of non-monitor CEM equipment malfunction		______	Hrs
17	Number of hours of quality assurance calibration		______	Hrs
		CO	______	Hrs
		NOX	______	Hrs
		O2	______	Hrs
18	Number of hours of other known CEM problems		______	Hrs
19	Number of hours of unknown CEM problems		______	Hrs
20	Total hours of CEM downtime		______	Hrs

CEMS Data Exclusion

21	Number of 1-hr emission avg. excluded due to Startups		______	Hrs
22	Number of 1-hr emission avg. excluded due to Shutdowns		______	Hrs
23	Number of 1-hr emission avg. excluded due to Malfunction		______	Hrs
24	Number of 1-hr emission avg. excluded due to Total		______	Hrs
25	Each rolling 12-month total tons of Co emissions for each month in the quarter	Attached 12 – month rolling Average		
26	Each 30-day rolling NOX average (ppm @7% oxygen) for each compliance period in the quarter	Attached 30-day rolling Average		

Customer Defined Reports continued

- USSC Annual Operating Report (AOR) – At the end of each year the CEMS DAS must produce the following summary of information for preparation of the AOR.

	Parameter	Units	Boiler No. 8
1	Average annual operation, hours per day	(hrs per day)	
2	Average annual operation, days per week	(days per week)	
3	Total hours of operation during the year	(hrs)	
4	Total hours of operation in December, January, and February	(days)	
5	Percent operation in December, January, and February	(%)	
6	Total hours of operation in March, April, and May	(days)	
7	Percent operation in March, April, and May	(%)	
8	Total hours of operation in June, July, and August	(days)	
9	Percent operation in June, July, and August	(%)	
10	Total hours of operation in September, October, and November	(days)	
11	Percent operation in September, October, and November	(%)	
12	Annual amount of bagasse burned in boiler	(1000 lbs)	
13	Anuual amount of fuel oil burned in boiler	(1000 gal)	
14	Annual amount of petroleum contaminated soil	(cubic yards)	
15	Annual amount of "on spec" used oil	(1000 gal)	
17	Hours of operation with bagasse firing	(hrs)	
18	Hours of operation with fuel oil firing	(hrs)	
19	Crop Season Sulfur content of fuel oil	(% S)	
20	Off Crop Season Sulfur content of fuel oil	(% S)	

- USSC Annual Title V Fee Form – At the end of each year the CEMS DAS must produce the following summary of information for Fee Form Preparation

	Parameter	Units	Boiler No. 8
1	Annual steam production	(lbs/yr)	
2	Heat content of steam	(Btu/lb)	
3	Total heat input for year	(MMBtu/yr)	
4	Total heat input for year from fuel oil	(MMBtu/yr)	
5	Total heat input for year from bagasse	(MMBtu/yr)	
6	Fuel oil SO2 Content – Crop Season	(% S)	
7	Fuel oil SO2 Content – Off Crop Season	(% S)	