Florida Power
CORPORATION

November 12, 1991

RECEIVED

NOV 13 1991

Bureau of
Air Regulation

Mr. Clair Fancy
Bureau of Air Regulation
Florida of Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Fancy:

RE: University of Florida Cogeneration Project

Enclosed please find five copies of the University of Florida Cogeneration Air Permit Application. Also enclosed is a check for the application fee of five thousand dollars ($5,000).

Florida Power Corporation is proposing to locate a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW. The steam generated by heat recovery steam generators (HRSGs) will be used for injection into the turbine for emission control and exported to the UF thermal distribution system. 100 percent of UF's steam requirements will be supplied by the cogeneration plant with existing UF boiler No. 4 and 5 utilized for back-up capacity.

The cogeneration plant will be located west of the existing UF Heat Plant #2 in the open area between the FPC substation and fuel oil storage tank farm. As part of the project, the large fuel oil tank (500,000 gallon) will be dismantled and removed.

Design specifications and emissions data are provided in the application. If you have any questions during the review process, please contact me at (813) 866-4511.

Sincerely,

W W Vierday

W.W. Vierday
Environmental & Licensing

CC: K. Kosky
E. Coffin
G. Reynolds
E. Holladay
A. Kutyna, NE Dist
J. Barsch, NE Dist Branch
G. Harper, EPA
C. Shaver, NPS

$5,000 pd.
11-13-91
Rcpt.#180712

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

RECEIVED
NOV 13 1991
Bureau of
Air Regulation

AC 01-204652
PSD-FL-181

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Facility* [X] New[1] [ ] Existing[1]

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

COMPANY NAME: *Florida Power Corporation* COUNTY: *Alachua*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *UF Cogeneration Project*

SOURCE LOCATION: Street *Mowry Road, University of Florida* City *Gainesville*

UTM: East *369.4 km* North *3,279.3 km*

Latitude *29* ° *38* ' *23* "N Longitude *82* ° *20* ' *55* "W

APPLICANT NAME AND TITLE: *Florida Power Corporation; R.W. Neiser, Senior Vice President*

APPLICANT ADDRESS: *3201 34th Street South, St. Petersburg, FL 33733*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Florida Power Corporation*

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

*Attach letter of authorization

Signed: Patricia K. Blizzard

R.W. Neiser, Sr VP, Legal and Gov Affairs
Name and Title (Please Type)

Date: 11/12/91 Telephone No. *(813) 866-5784*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

[1]See Florida Administration Code Rule 17-2.100(57) and (104)

Florida Power
CORPORATION

Richard W. Neiser
Senior Vice President
Legal and
Governmental Affairs

March 8, 1991

TO WHOM IT MAY CONCERN

Subject: Letter of Authorization

Please be advised that Patricia K. Blizzard, Director Environmental Services Department, and Mr. W. Jeffrey Pardue, Manager, Environmental Programs - Regulatory, are authorized to represent Florida Power Corporation in matters relating to necessary permits and reporting documentation required from regulatory authorities in the areas of air, water, power plant site certifications and transmission line certifications, or hazardous and solid materials issues.

Sincerely,

Richard W. Neiser

RWN:sp

Post Office Box 14042, St. Petersburg, Florida 33733 · 813-866-5784
A Florida Progress Company

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed Kennard F. Kosky

Kennard F. Kosky
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *14996* Date: 11/5/91 Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

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

Construction of a cogeneration facility that consists of one combustion turbine and associated heat recovery steam generator; see Section 2.0 in PSD Application

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

Start of Construction *February 1, 1992* Completion of Construction *April 1, 1994*

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

The cost of control is integral to the design of the project; low NO_x *combustors using wet injection and natural gas will reduce emission of air pollutants.*

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

The facility will include five boilers, three of which will be shut down. The permit numbers for these sources are: A001-136997 (Boiler 1), A001-136998 (Boiler 2), A001-136999 (Boiler 3), A001-136570 (Boiler 4) and A001-136570 (Boiler 5). See discussion in Section 2.3 of PSD Application.

E. Requested permitted equipment operating time: hrs/day *24*; days/wk *7*; wks/yr *52*;
If power plant, hrs/yr *8,760*; if seasonal, describe:
See Section 2.0

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

1. Is this source in a non-attainment area for a particular pollutant? *NO*

a. If yes, has "offset" been applied?

b. If yes, has "Lowest Achievable Emission Rate" been applied?

c. If yes, list non-attainment pollutants.

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *YES*

3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *YES*

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *YES*

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? *NO*

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? *NO*

a. If yes, for what pollutants?

b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

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

PSD Permit Application is attached.

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

A. Raw Materials and Chemicals Used in your Process, if applicable: ***Not applicable***

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) ***Not applicable***

1. Total Process Input Rate (lbs/hr): ____________________

2. Product Weight (lbs/hr): ____________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) ***See Table 2-1 in PSD Permit application***

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*197.5*	*20.0*	*0.8% Sulfur*	*316.1*	*197.5*	*20.0*	***See***
PM	*10*	*49.9*	*NA*	*NA*	*10*	*49.9*	***Figure 2-1***
NO_x	*66.3*	*234*	*126 ppmvd*	*198.9*	*66.3*	*234*	***in PSD***
CO	*70.5*	*415.2*	*NA*	*NA*	*70.5*	*415.2*	***Application***
VOC	*4.03*	*39.2*	*NA*	*NA*	*4.03*	*39.2*	

[1]See Section V, Item 2.
[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input) ***NSPS--0.8% sulfur oil and 75 ppmvd NO_x corrected for heat rate, i.e., 126 ppmvd; FDER Rule 17-2.660.***
[3]Calculated from operating rate and applicable standard.
[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) *See Section 4.0 in PSD Application*

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels *See Table A-1 in PSD Permit Application*

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas-CT	*<367,818.5 CF*[a]	*367,818.5 CF*	*348 @ Operating Conditions*
Natural Gas-DB	*197,907.0 CF*[b]	*197,674.4 CF*	*187*
Fuel Oil-CT	*1,039.6 lb*[c]	*20,792.4 lb*	*382.6 Operating*

CT = comubstion turbine; DB = duct burner
*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.
[a]*8,760 hr/yr;* [b]*7,884 hr/yr;* [c] *438 hr/yr*
Fuel Analysis:

Percent Sulfur: *NG = 1 grain/100 CF; oil = 0.5% sulfur* Percent Ash: *<0.1*

Density: *~7.2 for oil* lbs/gal Typical Percent Nitrogen: *<0.015*

Heat Capacity: *NG = 946 Btu/CF; Oil = 18,400* BTU/lb *132,480 (Oil)* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD Permit Application*

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

All wastewaters generated from the plant will be discharged to the University of Florida wastewater treatment plant.

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

Stack Height: ___93___ ft. Stack Diameter: ___9.75___ ft.

Gas Flow Rate: ___325,200[a]___ ACFM ___320,364[a]___ DSCFM Gas Exit Temperature: ___257___ °F.

Water Vapor Content: ___11.25 (Gas) 8.54 (Oil)___ % Velocity: ___72.6 (Gas) 71.5 (Oil)___ FPS

[a] *Gas Firing--see Table A-1 for more detail.*

SECTION IV: INCINERATOR INFORMATION

Not applicable

Type of Waste	Type O (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

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

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ______

Date Constructed ______ Model No. ______

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

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

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ______

Brief description of operating characteristics of control devices: ______________________

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

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   See Table A-1 in the PSD Application
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. ***See Appendix A in PSD Application***
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Appendix A in the PSD Application
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Table A-1 in the PSD Application
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See Appendix A in the PSD Application
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-1 in the PSD Application
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in the PSD Application
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 2-1 in the PSD Application

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
Application fee attached

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

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source? *See Section 4.2 in PSD Application.*

[X] Yes [ ] No *40 CFR Part 60 Subpart GG; Subpart Db.*

Contaminant	Rate or Concentration
NO_x - CT	*75 ppmvd corrected to 15% O_2 and heat rate*
SO_2 - CT	*0.8% sulfur*
NO_x - DB	*0.2 lb/10^6 Btu heat input*

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[X] Yes [ ] No *See Section 4.0 in PSD Application*

Contaminant	Rate or Concentration

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

Contaminant	Rate or Concentration
See Section 4.0 in PSD Application	

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

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

See Section 4.0 in PSD Application

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

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

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

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

3.

a. Control Device:
b. Operating Principles:

c. Efficiency:[1]
d. Capital Cost:

e. Useful Life:
f. Operating Cost:

g. Energy:[2]
h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

4.

a. Control Device:
b. Operating Principles:

c. Efficiency:[1]
d. Capital Cost:

e. Useful Life:
f. Operating Cost:

g. Energy:[2]
h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

F. Describe the control technology selected:

1. Control Device:
2. Efficiency:[1]

3. Capital Cost:
4. Useful Life:

5. Operating Cost:
6. Energy:[2]

7. Maintenance Cost:
8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:
(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

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

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data *Not applicable--see Sections 3.4.2.2 and 5.2 in PSD Application.*

1. ________ no. sites ________ TSP ________ ( ) SO^{2*} ________ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded ____________________

Attach all data or statistical summaries to this application.

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

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling *See Section 6.0 in PSD Application*

1. ______ Year(s) of data from ________/____/________ to ________/____/________
month day year month day year

2. Surface data obtained from (location)________________________________

3. Upper air (mixing height) data obtained from (location) ________________

4. Stability wind rose (STAR) data obtained from (location) ________________

C. Computer Models Used *See Section 6.0 in PSD Application*

1. ________________________________ Modified? If yes, attach description.

2. ________________________________ Modified? If yes, attach description.

3. ________________________________ Modified? If yes, attach description.

4. ________________________________ Modified? If yes, attach description.

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

D. Applicants Maximum Allowable Emission Data *See Section 6.0 in PSD Application*

Pollutant	Emission Rate
TSP	________________ grams/sec
SO^2	________________ grams/sec

E. Emission Data Used in Modeling *See Section 6.0 in PSD Application*

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

F. Attach all other information supportive to the PSD review. *PSD Application attached*

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. *See Section 4.0 in PSD Application*

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. *See Section 4.0 in PSD Application*

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR THE PROPOSED UNIVERSITY OF FLORIDA COGENERATION FACILITY

Prepared For:

Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

Prepared By:

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, FL 32605

November 1991
91062C1

TABLE OF CONTENTS
Page 1 of 3

TABLE OF CONTENTS
Page 2 of 3

TABLE OF CONTENTS
Page 3 of 3

LIST OF TABLES

LIST OF TABLES

LIST OF FIGURES

ACRONYMS AND ABBREVIATIONS
(Page 1 of 2)

AAQS	Ambient Air Quality Standards
As	arsenic
BACT	best available control technology
Be	beryllium
10^6 Btu/hr	million British thermal units per hour
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FL	Fluoride
FPC	Florida Power Corporation
ft	foot/feet
ft^3/yr	cubic feet per year
g/s	grams per second
GE	General Electric
GEP	good engineering practice
H_2SO_4	sulfuric acid
Hg	mercury
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term
ISCST	Industrial Source Complex Short-Term
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
kW	kilowatt
kWh/yr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW	megawatt
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service

ACRONYMS AND ABBREVIATIONS
(Page 1 of 2)

AAQS	Ambient Air Quality Standards
As	arsenic
BACT	best available control technology
Be	beryllium
10^6 Btu/hr	million British thermal units per hour
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FL	Fluoride
FPC	Florida Power Corporation
ft	foot/feet
ft^3/yr	cubic feet per year
g/s	grams per second
GE	General Electric
GEP	good engineering practice
H_2SO_4	sulfuric acid
Hg	mercury
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term
ISCST	Industrial Source Complex Short-Term
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
kW	kilowatt
kWh/yr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW	megawatt
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service

ACRONYMS AND ABBREVIATIONS
(Page 2 of 2)

PM	particulate matter
PM(TSP)	total suspended particulate matter
PM10	particulate matter less than or equal to 10 micrometers
ppm	parts per million
ppmvd	parts per million volume, dry
PSD	prevention of significant deterioration
SIP	State Implementation Plan
SO_2	sulfuric dioxide
TPH	tons per hour
TPY	tons per year
$\mu g/m^3$	micrograms per cubic meter
UF	University of Florida
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound

1.0 INTRODUCTION

Florida Power Corporation (FPC) is proposing to locate a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed site, which is located in Gainesville, Alachua County (Figure 1-1), will be under the common control of FPC when the cogeneration plant becomes operational. This includes the central heat plant that consists of 5 existing boilers; 3 boilers will be taken out of service and 2 boilers will be used as back-up. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW (Table 1-1). Steam generated by heat recovery steam generators (HRSGs) will be used to supply steam for UF. A plot plan for the facility is presented in Figure 1-2.

KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted by FPC to provide air permitting services for the facility. Initially, preliminary analyses were performed to determine compliance with prevention of significant deterioration (PSD) increments and preconstruction _de minimis_ monitoring levels for the proposed plant only. A full PSD review was then performed to determine whether significant air quality deterioration will result from the proposed facility and other PSD increment-consuming sources and to determine compliance with ambient air quality standards (AAQS). The PSD review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses.

The proposed project will be a major facility because emissions of at least one regulated pollutant exceeds 250 tons per year (TPY). PSD review is required for these emissions and for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. The potential emissions from the proposed project will exceed the PSD significant emission rates for carbon monoxide (CO), particulate matter with an aerodynamic diameter of 10 micrometers (PM10), and arsenic (As). Therefore, the project is subject to PSD review for these pollutants.

Table 1-1. Characteristics of the University of Florida Cogeneration Facility

Characteristic	Data
Capacity (kW)	
Combustion Turbine	43,262
Equipment Characteristics	
Type of CT	GE LM 6000
CT Heat Input (10^6 Btu/hr)	348
Duct Burner (10^6 Btu/hr)	187
Nitrogen Oxides Injection Steam, Natural Gas Firing (lb/hr)	31,402
Nitrogen Oxides Injection Water, Oil Firing (lb/hr)	22,504
Fuels	
CT, Natural Gas, Primary (ft^3/hr)	367,818.5
CT, Distillate Oil, Emergency Backup (gas curtailment only)(lb/hr)	20,792.4
Duct Burner, natural gas only (ft^3/hr)	197,674.4

Note: 10^6 Btu/hr = British thermal units per hour
CT = Combustion turbine
ft^3/hr = cubic feet per hour
GE = General Electric
HRSG = heat recovery steam generator
kW = kilowatt
lb/hr = pounds per hour

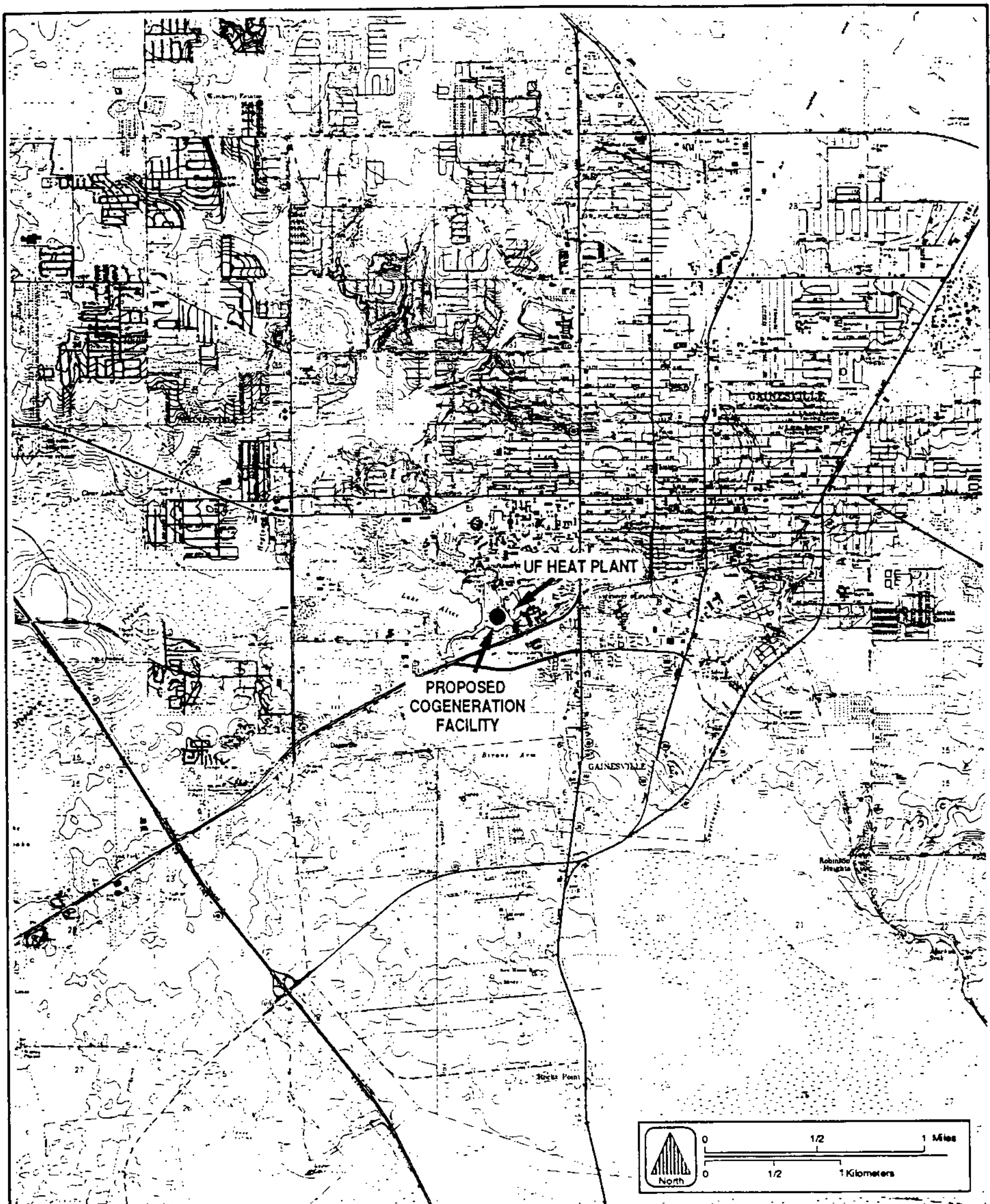

Figure 1-1 LOCATION OF UF COGENERATION FACILITY

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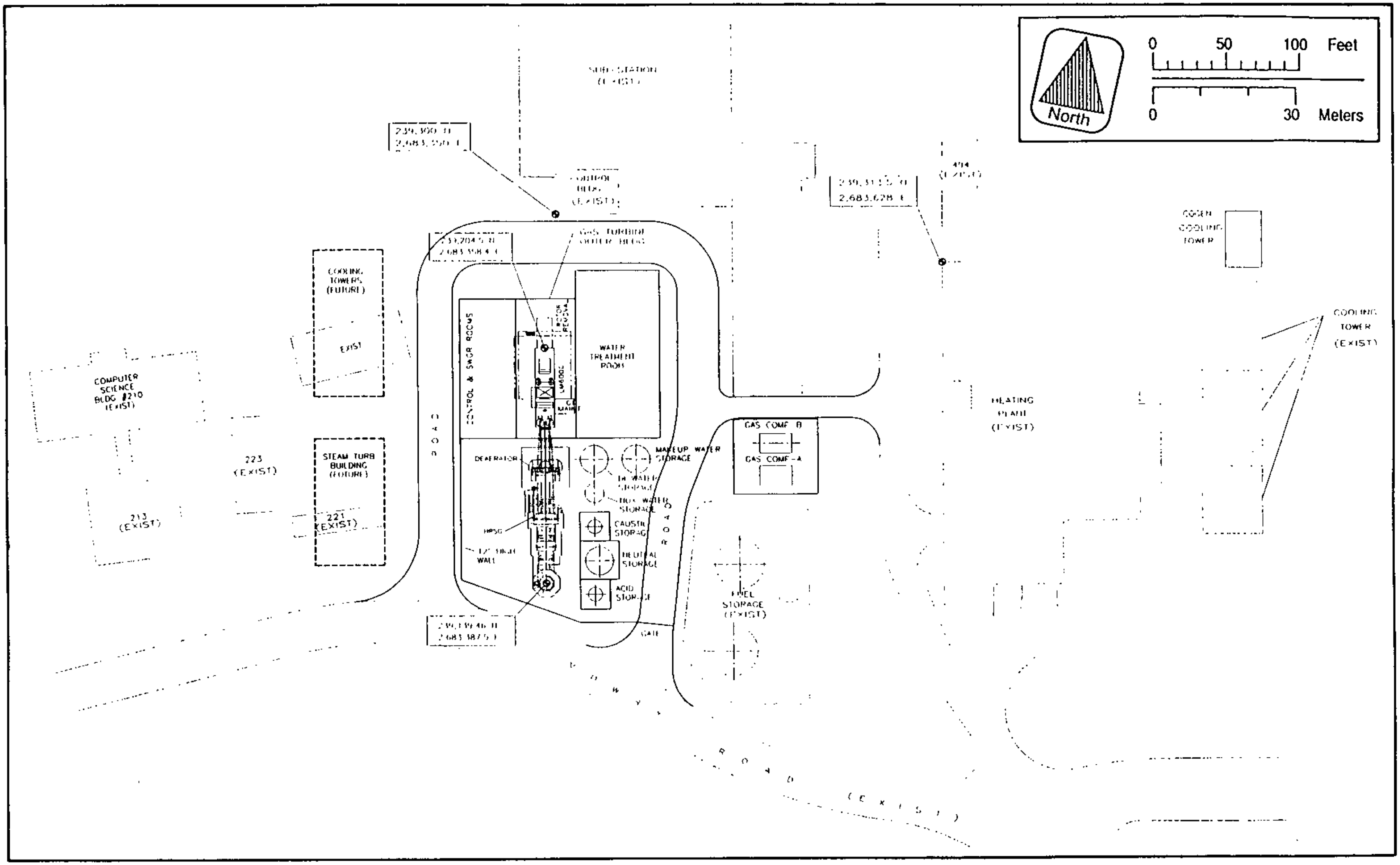

Figure 1-2 PLOT PLAN FOR UF COGENERATION FACILITY

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This report is presented in seven sections. A general description of the proposed operation is given in Section 2.0. The air quality review requirements and applicability of the project to the PSD and nonattainment regulations are presented in Section 3.0. The control technology review for the project applicable under the U.S. Environmental Protection Agency's (EPA's) current top-down approach is discussed in Section 4.0. A discussion of the need for air quality monitoring data to satisfy the PSD preconstruction monitoring requirements is presented in Section 5.0. The air source impact analysis approach is presented in Section 6.0. The results of the air quality analyses and additional impact analyses associated with the project's impacts on vegetation, soils, and associated growth are discussed in Section 7.0.

2.0 PROJECT DESCRIPTION

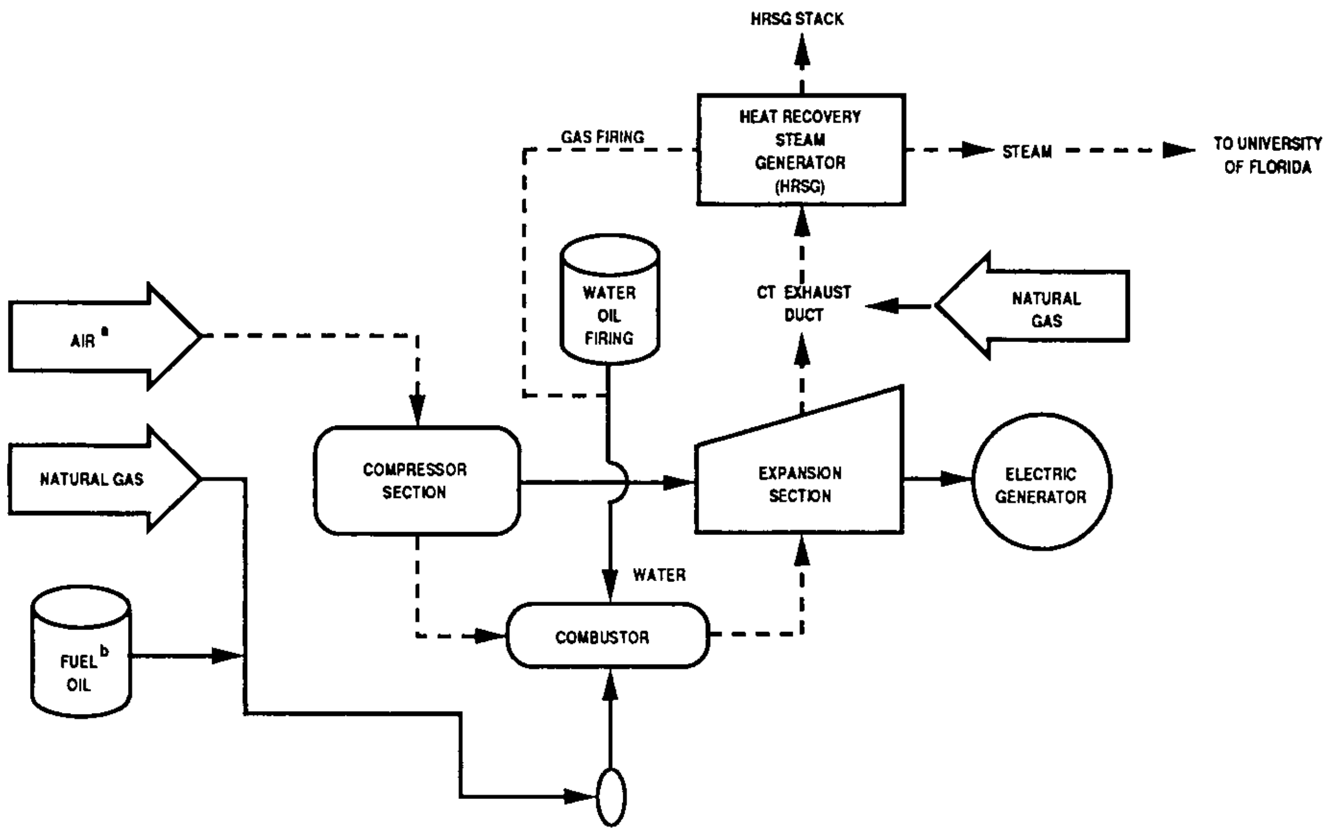
2.1 GENERAL DESCRIPTION

The proposed project will consist of installing one CT and one HRSG at the UF Central Heat Plant. The UF Central Heat Plant has five existing boilers which are primarily fired with natural gas with residual oil used as backup. The project will replace existing boilers 1, 2, and 3; Boilers 4 and 5 will be operated as back-up for the cogeneration plant. The existing boilers and cogeneration plant will be under the common control of FPC. Therefore, the "facility" for which PSD approval is requested includes the existing Central Heat Plant and the cogeneration plant. This is consistent with the term defined in Florida Department of Environmental Regulation (FDER) Rule 12-2.100(78) Florida Administrative Code (F.A.C.).

The CT will be the new General Electric (GE) LM 6000 machine. The LM 6000 is a newly developed aircraft derivative machine that has thermal efficiency of approximately 40 percent. This efficiency, developed from advanced aircraft compressor and turbine technology, makes the LM 6000 more efficient than the advanced heavy frame combustion turbine being offered by certain manufacturers (e.g., the GE Frame combustion turbine). A description of this machine is presented in Appendix A. The CT exhaust will go through the HRSG and exit to the atmosphere through an individual stack. There will be no bypass stack on the CT for simple cycle operation. A flow diagram of the project is presented in Figure 2-1.

The primary fuel for firing the CT will be natural gas; distillate fuel oil will be used as emergency backup when natural gas is curtailed. Operation with distillate oil will not exceed 438 hours per year. There will be supplementary firing of natural gas only in the HRSG.

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Wet injection will be used to control



NOTES:

(a) COOLED FROM AMBIENT
(b) EMERGENCY BACKUP ONLY - 10 DAYS/YEAR

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED UNIT

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emissions of nitrogen oxides (NO_x) from the CT. The use of natural gas or low-sulfur (0.5-percent sulfur maximum) distillate fuel oil will minimize the emissions of sulfur dioxide (SO_2) from the unit.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The emissions and stack parameters for the CT are presented in Table 2-1. These data represent the maximum emissions since air inlet coolers may be installed on the CT to maintain a compressor temperature of 51°F, which will increase generating capability and regulate temperature. Maximum potential annual emissions for the project are presented in Table 2-2. Performance information and maximum emission rates for regulated criteria pollutants, regulated noncriteria pollutants, and nonregulated pollutants from the CT are presented in Tables A-1 through A-5 of Appendix A.

Supplemental firing with natural gas will take place in the duct between the CT and the HRSG. The supplemental firing, at a maximum rate of 187 million British thermal units per hour (x 10^6 Btu/hr), will allow the HRSG to produce additional steam. The firing of natural gas will produce additional air emissions, as shown in Tables 2-1 and 2-2, for the maximum firing rate. These emissions will combine with the CT exhaust gases only during natural gas firing and exhaust through the HRSG stack. Supplemental firing will be limited to an equivalent of 7,884 hours per year at maximum capacity (i.e., 1,474,308 x 10^6 Btu).

2.3 EXISTING FACILITY EMISSIONS

The proposed facility will include the existing Central Heat Plant which consists of five boilers firing natural gas and residual oil. Boilers 1, 2 and 3 will be taken out of service when the cogeneration plant becomes operational. Boilers 1 and 2 have heat input capacities of 88.5 million Btu per hour. Boiler 3 has a heat input capacity of 160.6 x 10^6 Btu/hr. Boilers 4 and 5 have heat input capacities of 71.7 and 172.2 x 10^6 Btu/hr and will be used only as back-up for the cogeneration plant. These boilers will be operated at lower capacity factors than in previous years. In addition, the use of residual oil in these boilers will be eliminated and

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 1 of 2)

Parameter	Fuel Type: Fuel Oil[a] Gas Turbine	Fuel Type: Natural Gas Gas Turbine[b]	Fuel Type: Natural Gas Duct Burner[c]
Stack Data (ft)			
Height	93	93	d
Diameter	9.75	9.75	d
Operating Data			
Temperature (°F)	257	257	d
Velocity (ft/sec)	71.5	72.59	d
Building Data (ft)			
Height	57	57	d
Length	54	54	d
Width	14	14	d
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	197.5	1.05	0.56
Particulate Matter	10.0	2.5	1.87
Nitrogen Oxides	66.3	35.0	18.7
Carbon Monoxide	70.5	69.5	28.1
Volatile Organic Compounds	4.03	1.59	8.04
Sulfuric Acid Mist	3.3	Neg	Neg
Lead	0.0034	Neg	Neg
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	43.3	4.6	2.23
Particulate Matter	2.2	10.95	7.37
Nitrogen Oxides	14.5	153.4	73.72

DB: $\frac{18.7 \text{ lb/hr}}{185 \text{ mmBtu/hr}} = .1$ lb/mmBtu

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 2 of 2)

	Fuel Type		
	Fuel Oil[a]	Natural Gas	
Parameter	Gas Turbine	Gas Turbine[b]	Duct Burner[c]
Carbon Monoxide	15.4	304.4	110.57
Volatile Organic Compounds	0.9	7.0	31.7
Sulfuric Acid Mist	3.5	Neg	Neg
Lead	0.00075	Neg	Neg

Note: °F = degrees Fahrenheit.
ft = feet.
ft/second = feet per second.
lb/hr = pounds per hour.
TPY = tons per year.

[a] Performance based on nitrogen oxide emissions of 42 parts per million by volume dry (corrected to 15 percent O_2); sulfur dioxide emissions based on an average sulfur content of 0.5 percent sulfur; annual emission data based on 438 hours per year.
[b] Performance based on nitrogen oxide emissions of 25 parts per million volume dry (corrected to 15 percent O_2); annual emissions data based on 8,760 hours/year (365 days per year) operation.
[c] Performance based on 187 x 10^6 Btu/hr heat input per heat recovery steam generators and 7,884 hours per year operation.
[d] Same as gas turbine natural gas; duct burners will not fire No. 2 oil.

Table 2-2. Maximum Annual Potential Emissions From Proposed Cogeneration Project

Pollutant	Fuel (TPY) Distillate Oil[a]	Natural Gas[b] Gas Turbine	Duct Burner	Total (TPY)
Sulfur Dioxide	43.3	4.4	2.2	49.9
Particulate Matter[c]	2.2	10.4	7.4	20.0
Nitrogen Oxide	14.5	145.7	73.7	233.9
Carbon Monoxide	15.4	289.2	110.6	415.2
Volatile Organic Compounds	0.9	6.7	31.7	39.2
Sulfuric Acid Mist	3.5	Neg	Neg	3.5
Lead	0.00075	Neg	Neg	0.00075

Note: Neg = negative.
PM10 = particulate matter with an aerodynamic diameter less than or equal to 10 micrometers.
TPY = tons per year.

[a]438 hours/year.
[b]95% capacity factor for gas turbine and 90% capacity for duct burner.
[c]PM10.

distillate oil, which will also be used as backup for the CT, will be used. Copies of the FDER permits are contained in Appendix B.

Because the facility consists of the Central Heat Plant, the net emissions decreases are creditable when evaluating PSD applicability [FDER Rule 17-2.500(2)(e)]. For the Central Heat Plant, the actual emissions representative of operation are presented in Table 2-3 for Boilers 1, 2, and 3, and Table 2-4 for Boilers 4 and 5. These emissions represent an average of the last complete 3-years (1988-90). A 3-year average is considered representative because operation of the Central Heat Plant is affected by meteorological conditions, i.e. heating and cooling requirements. A 3-year average is statistically more representative of the range of meteorological conditions that can influence steam demands. Copies of the annual operation reports are contained in Appendix B.

Since Boilers 4 and 5 will be operated as back-up for the cogeneration plant, the operation of these sources will be restricted based on the fuel use listed in Table 2-5. Also, the emission estimates in this table reflect the use of distillate oil rather than residual oil. This table also provides emissions for the fuel use proposed for these sources in the facility. These fuel limits will provide net emission decreases for the facility which are presented in Table 2-6.

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 1 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	208		368		
No. 6 Fuel Oil[c]					
(gal/yr)		0		12,519	
(% sulfur)		0.964		1.85	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	12.64[d]	3	21.5[d]	
Particulate Matter (PM10)	3	8.97[d]	3	15.27[d]	
Sulfur Dioxide	0.6	151.3[e]	0.6	290.5[e]	
Nitrogen Oxides	140	55	550	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	1	0.3	0.28	
Volatile Organic Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	2.32	Neg.	6.57	
Emission Rate (TPY)					
Particulate Matter	0.31	0.00	0.55	0.13	1.00
Particulate Matter (PM10)	0.31	0.00	0.55	0.10	0.96
Sulfur Dioxide	0.062	0.00	0.110	1.82	1.99
Nitrogen Oxides	14.57	0.00	101.28	0.42	116.26
Carbon Monixide	3.64	0.00	7.37	0.03	11.04

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 2 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (methane)	0.31	0.00	0.06	0.00	0.37
Volatile Organic Compounds (nonmethane)	0.29	0.00	0.26	0.00	0.55
Lead	Neg.	0.0000	Neg.	0.0000	0.000
Total Fluorides	Neg.	0.000	Neg.	0.000	0.000
Mercury	Neg.	0.00000	Neg.	0.00000	0.000
Beryllium	Neg.	0.00000	Neg.	0.00000	0.00000
Arsenic	Neg.	0.0000	Neg.	0.0000	0.0000
Sulfuric Acid Mist	Neg.	0.00	Neg.	0.04	0.04

Note: ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per milimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matte
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boilers 1 and 2 have heat input capacities less than 100 x 10^6 British thermal units per hour; therefore, emission factors for industrial boilers were used.
[b] Boiler 3 has a heat input capacity of greater than 100 x 10^6 British thermal units per hour; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned					
(MM ft^3/yr)	156		453		
No. 6 Fuel Oil					
(gal/yr)		55,207		190,515	
(% sulfur)		1.623		1.97	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	19.23[d]	3	22.7[d]	
Particulate Matter (PM10)	3	13.65[d]	3	16.12[d]	
Sulfur Dioxide	0.6	254.8[e]	0.6	309.3[e]	
Nitrogen Oxides	140	55	550	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic					
Compounds (methane)	3	1	0.3	0.28	
Volatile Organic					
Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	3.98	Neg.	7.0	
Emission Rate (TPY)					
Particulate Matter	0.23	0.53	0.68	2.16	3.61
Particulate Matter (PM10)	0.23	0.38	0.68	1.54	2.82
Sulfur Dioxide	0.05	7.03	0.14	29.46	36.68
Nitrogen Oxides	10.89	1.52	124.47	6.38	143.26
Carbon Monoxide	2.72	0.14	9.05	0.48	12.39
Volatile Organic					
Compounds (methane)	0.23	0.03	0.07	0.03	0.36

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (nonmethane)	0.22	0.01	0.32	0.07	0.61
Lead	Neg.	0.0001	Neg.	0.0004	0.0005
Fluorides	Neg.	0.0014	Neg.	0.0050	0.006
Mercury	Neg.	0.00001	Neg.	0.00005	0.00006
Beryllium	Neg.	0.00002	Neg.	0.00006	0.00008
Arsenic	Neg.	0.0001	Neg.	0.0003	0.0004
Sulfuric Acid Mist	Neg.	0.11	Neg.	0.67	0.78

Note: ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per milimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	75		210		
No. 2 Fuel Oil[c]					
(gal/yr)		25,000		100,000	
(% sulfur)		0.5		0.5	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	8[d]	3	8[d]	
Particulate Matter (PM10)	3	5.68[d]	3	5.68[d]	
Sulfur Dioxide	0.6	78.5[e]	0.6	78.5[e]	
Nitrogen Oxides	140	20	550	24	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	0.052	0.3	0.052	
Volatile Organic Compounds (nonmethane)	2.8	0.2	1.4	0.2	
Lead	Neg.	0.0013	Neg.	0.0042	
Fluorides	Neg.	0.0049	Neg.	0.052	
Mercury	Neg.	0.00045	Neg.	0.00048	
Beryllium	Neg.	0.00038	Neg.	0.00063	
Arsenic	Neg.	0.00063	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	1.225	Neg.	1.225	
Emission Rate (TPY)					
Particulate Matter	0.11	0.10	0.32	0.40	0.93
Particulate Matter (PM10)	0.11	0.07	0.32	0.28	0.78
Sulfur Dioxide	0.02	0.98	0.06	3.93	4.99
Nitrogen Oxides	5.25	0.25	57.75	1.22[f]	64.47
Carbon Monoxide	1.31	0.06	4.20	0.25	5.83

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Volatile Organic Compounds (methane)	0.11	0.00	0.03	0.00	0.15
Volatile Organic Compounds (nonmethane)	0.11	0.00	0.15	0.01	0.26
Lead	Neg.	0.0000	Neg.	0.0002	0.0002
Fluorides	Neg.	0.0001	Neg.	0.0026	0.003
Mercury	0.0000	0.0000	0.0000	0.0000	0.00003
Beryllium	Neg.	0.0000	Neg.	0.0000	0.00004
Arsenic	Neg.	0.0000	Neg.	0.0001	0.0002
Sulfuric Acid Mist	Neg.	0.02	Neg.	0.06	0.08

Note: ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per milimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has a heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (See Appendix A).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Nitrogen oxides emissions based on ratio of residual and distillate oil emission factors.

Table 2-6. Net Emission Reductions From Boilers 1 through 5 at UF Central Heating Plant

	Net Emission Reduction (TPY)		
Pollutant	Boilers[a] 1, 2 and 3	Boilers[b] 4 and 5	Total
Particulate Matter	-1.00	-2.68	-3.68
Particulate Matter (PM10)	-0.96	-2.04	-3.00
Sulfur Dioxide	-1.99	-31.69	-33.68
Nitrogen Oxides	-116.26	-78.79	-195.05
Carbon Monoxide	-11.04	-6.56	-17.60
Volatile Organic Compounds (methane)	-0.37	-0.21	-0.58
Volatile Organic Compounds (nonmethane)	-0.55	-0.35	-0.90
Lead	-0.0000	-0.0003	-0.0003
Fluorides	-0.0003	-0.0037	-0.0041
Mercury	-0.00000	-0.00003	-0.00003
Beryllium	-0.00000	-0.00004	-0.00005
Arsenic	-0.0000	-0.0002	-0.0002
Sulfuric Acid Mist	-0.0411	-0.6999	-0.7410

Note: TPY = tons per year.

[a]Based on emissions in Table 2-1.
[b]Based on subtracting emissions in Table 2-2 from emissions in Table 2-3.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed project. These regulations must be satisfied before the proposed cogeneration plant can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the FDER.

A "major facility" is defined as any one of 28 named source categories that has the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels (μg/m³)

Pollutant	Averaging Time	AAQS[a] National Primary Standard	AAQS[a] National Secondary Standard	AAQS[a] State of Florida	PSD Increments[a] Class I	PSD Increments[a] Class II	Significant Impact Levels[b]
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

[a] Short-term maximum concentrations are not to be exceeded more than once per year.
[b] Maximum concentrations are not to be exceeded.
[c] Proposed October 5, 1989.
[d] Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

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

In addition to these analyses, a new facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated, based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks,

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations (Page 1 of 2)

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 tons per year[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	[c]	NM
Radionuclides	NESHAP	[c]	NM
Inorganic Arsenic	NESHAP	[c]	NM

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations (Page 2 of 2)

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)

[a] Short-term concentrations are not be be exceeded.
[b] No de minimis concentration; an increase in volatile organic compounds emissions of 100 tons per year or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below de minimis monitoring concentrations.

NAAQS - National Ambient Air Quality Standards.
NM - No ambient measurement method.
NSPS - New Source Performance Standards.
NESHAP - National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ - micrograms per cubic meter.
TPY - tons per year.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration as a result of emissions of NO_x and established PSD increments for nitrogen dioxide (NO_2) concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDER has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP)

concentrations, and after February 8, 1988, for NO_2 concentrations; and

2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2,
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application, and
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.).

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that Best Available Control Technology (BACT) be applied to control emissions from the source [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C., as:

> An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT), (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDER may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised) (EPA, 1987b). The source impact analysis for criteria pollutants may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be used for impact analysis. A S-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDER [Chapter 17-2.270, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m) (213 feet), or
2. A height established by applying the formula: Hg = H + 1.5L
   where: Hg = GEP stack height,
   H = Height of the structure or nearby structure, and
   L = Lesser dimension (height or projected width) of nearby structure(s), or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all volatile organic compound (VOC) sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

The project site is located in Alachua County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Alachua County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The site is located more than 100 km from the closest PSD Class I areas, i.e., the Chassahowitzka National Wilderness Area and Okefenokee National Wilderness Area.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a modification to a major facility because the potential emissions of any regulated pollutant exceed 250 TPY; therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for CO, PM10, and inorganic As. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

Based on the net increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for PM10, CO, and As. However, if the net increase in impact of a pollutant is less than the *de minimis* monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement is provided for in the FDER regulations [FDER Rule 17-2.500(3)(e)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data (e.g., FDER) or the collection of on-site data.

Maximum predicted impacts as a result of the net increase associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum net increase in impact is below the respective *de minimis* monitoring concentration for all pollutants. There is no acceptable ambient monitoring method for As; therefore, monitoring is not required for this pollutant.

Table 3-3. Net Increase in Emissions Due To the UF Cogeneration Facility Compared to the PSD Significant Emission Rates

	Emissions (TPY)				
Pollutant	Potential Emissions From Proposed Turbines	Net Emission Reduction From Boilers 1-5	Increase Net Emissions	Significant Emission Rate	PSD Review
Sulfur Dioxide	49.9	33.7	16.2	40	No
Particulate Matter (TSP)	20.0	3.68	16.3	25	No
Particulate Matter (PM10)	20.0	3.00	17.0	15	Yes
Nitrogen Dioxide	233.9	195.1	38.8	40	No
Carbon Monoxide	415.2	17.6	397.6	100	Yes
Volatile Organic Compounds	39.2	0.90	38.3	40	No
Lead	0.00075	0.0003	0.00045	0.6	No
Sulfuric Acid Mist	3.5	0.74	2.8	7	No
Total Fluorides	0.0027	0.0041	-0.0014	3	No
Total Reduced Sulfur[a]	Neg	Neg	Neg	10	No
Reduced Sulfur Compounds[a]	Neg	Neg	Neg	10	No
Hydrogen Sulfide[a]	Neg	Neg	Neg	10	No
Asbestos[a]	Neg	Neg	Neg	0.007	No
Beryllium	0.00021	0.00005	0.0002	0.0004	No
Mercury	0.00025	0.00003	0.0002	0.1	No
Vinyl Chloride[a]	Neg	Neg	Neg	1	No
Benzene[a]	Neg	Neg	Neg	0	No
Radionuclides[a]	Neg	Neg	Neg	0	No
Inorganic Arsenic	0.00035	0.0002	0.00015	0	Yes

Note: Neg = Negligible.
TPY = tons per year.
All calculations based on 59°F peak load condition.

[a]Emissions of these pollutants considered not to have any emission rate increase.
[b]Based on a maximum sulfur content specification of 0.1 percent in fuel oil.

Table 3-4. Predicted Net Increase in Impacts Due To the UF Cogeneration Facility Compared to PSD De Minimis Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$) Predicted Net Increase Impacts[a]	Concentration ($\mu g/m^3$) De Minimis Monitoring Concentration
Particulate Matter (PM10)	4.63 (2.22)	10, 24-hour
Carbon Monoxide	42.4 (58.7)	575, 8-hour
Inorganic Arsenic	NA	NM

Note: NA - Not applicable.
NM - No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by EPA.

[a] TSP and PM10 impacts based on maximum emissions at 100-percent load and 100-percent capacity factor when firing oil, which will be limited to no more than about 18 days per year. Impacts for natural gas, the primary fuel, are shown in parentheses. Concentrations indicate the highest predicted values.

3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The proposed stack for the proposed turbine will be 93 feet (ft) in height (28.35 m) and, therefore, do not exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.3 NONATTAINMENT REVIEW

The project site is located in Alachua County, which is classified as an attainment area for all criteria pollutants. The plant is also located more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has promulgated guidelines (FDER, 1991) to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. All regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to No Threat Levels (NTL) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered not to pose a significant health risk.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of PM10, CO, and inorganic As (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring the top-down approach.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbine are codified in 40 CFR 60, Subpart GG. These regulations apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided.

Table 4-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 British thermal units per hour.
[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase Nitrogen Oxide Percent By Volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

For the proposed CT, the NSPS emission limit would be 126 ppm corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent. The applicable NSPS for the duct burners will be 40 CFR 60, Subpart Db. The applicable requirements are presented in Table 4-2.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 CARBON MONOXIDE (CO)

4.3.1.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project.

Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. When wet NO_x control systems are employed, the amount of water or steam injected in the combustion zone also affects combustion efficiency. For the CTs being evaluated and with wet injection NO_x control, CO emissions will not exceed 75 ppm, corrected to dry conditions when firing either natural gas or distillate fuel oil. These emission limits are based on calculated CO levels with margins added to account for the lack of operating experience with the LM 6000. Actual emissions under full-load conditions are expected to be less than one-half of those presented in this application.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use this Lowest Achievable Emission Rate (LAER) technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

Table 4-2. Federal NSPS for Industrial Steam-Generating Units, 40 CFR 60, Subpart Db[a] (Page 1 of 2)

Pollutant	Emission Limitation for Gaseous or Liquid Fuels
Particulate Matter	Natural gas - no emission limits Oil - 0.10 lb/10^6 Btu
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide[b]	Natural gas - no emission limits Oil: 1) Annual capacity factor for oil > 30% - 0.80 lb/10^6 Btu <u>and</u> 90% reduction in potential emissions 2) Annual capacity factor for oil < 30%[c] - 0.30 lb/10^6 Btu (no percentage reduction requirements) 3) Combustion of 0.3 lb sulfur dioxide/10^6 Btu or less oil - 0.30 lb/10^6 Btu - No percentage reduction requirements
Nitrogen Oxides	Natural gas/distillate oil: 1) Low heat release rate unit - 0.10 lb/10^6 Btu 2) High heat release rate unit - 0.20 lb/10^6 Btu 3) Duct burner in combined cycle system - 0.20 lb/10^6 Btu Residual oil: 1) Low heat release rate unit - 0.30 lb/10^6 Btu 2) High heat release rate unit - 0.40 lb/10^6 Btu 3) Duct burner in combined cycle system - 0.40 lb/10^6 Btu

Table 4-2. Federal NSPS for Industrial Steam-Generating Units, 40 CFR 60, Subpart Db[a] (Page 2 of 2)

Pollutant	Emission Limitation for Gaseous or Liquid Fuels

Note:
< = less than.
> = greater than.
$lb/10^6$ Btu = pounds per million British thermal unit.
$SO_2/10^6$ Btu = sulfur dioxide per million British thermal unit.

[a] Applies to any device that combusts fuel to produce steam and that has a maximum heat input of more than 100 x 10^6 British thermal units per hour. Sources subject to Subpart Da are not subject to Subpart Db.
[b] Compliance determined on a 30-day, rolling average basis (with certain exceptions).
[c] Includes combines cycle system where 30 percent or less of the heat input to the steam generator is from combustion of oil in the duct burner and 70 percent or more of the heat input is from the gas turbine exhaust gases entering the duct burner.

Source: 40 CFR 60, Subpart Db.

4.3.1.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the unit will require startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling. There is also a lack of demonstrated operation with oil firing.

Combustion design is dependent upon the manufacturer's operating specifications, which include the air-to-fuel ratio and the amount of steam injected. The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

For the project, the following alternatives were evaluated for natural gas firing as BACT:

1. Oxidation catalyst at 10 parts per million volume, dry (ppmvd); maximum annual CO emissions are 42.6 TPY;
2. Combustion controls at 75 percent control; maximum annual CO emissions are 319.8 TPY.

4.3.1.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $473,686 (Table 4-3), with a cost effectiveness of about $1,833/ton of CO removed. The cost effectiveness is based on 87 percent efficiency (75 ppmvd to 10 ppmvd). No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 753,360 kilowatt-hour per year (kWh/yr) would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 60 residential customers over a year. To replace this lost energy, about 0.75×10^{10} Btu/yr or about 7.5 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.4 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable for the following reasons:

Table 4-3. Capital and Annualized Cost for Oxidation Catalyst (Page 1 of 2)

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	75,833	Manufacture Estimate - $1,750 per lb/sec mass flow
2. Exhaust Stack Modification	75,000	Engineering Estimate - $75,000/CT
3. Installation	145,139	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	43,542	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	58,056	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	29,028	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	11,611	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	109,552	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	146,622	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	694,383	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	81,562	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	429,722	Manufacture Estimate - $1,750 per lb/sec mass flow
B. Contingency	107,431	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	537,153	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	215,997	Capital Recovery of 10% over 3 years
III. OPERATING & MAINTENANCE COSTS		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,262	4 hours/week, 52 weeks/year, $22/hour and 15% supervisor cost
2. Maintenance	6,158	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	8,413	Capital Carrying cost (10% over 20 years) for catalyst for 1 charge
B. ENERGY COSTS		
1. Heat Rate Penalty	38,582	0.2% heat reat penalty. $50/MW energy loss
2. MW Loss Penalty (Catalyst Changeout)	51,600	Loss of 43 MW for one day
3. Fuel Escalation Costs	17,539	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	26,930	25% of energy costs

Table 4-3. Capital and Annualized Cost for Oxidation Catalyst (Page 2 of 2)

Cost Component	Cost ($)	Basis
C. INDIRECT:		
1. Overhead	6,852	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	12,315	1% of Total and Recurring Capital Cost
3. Insurance	12,315	1% of Total and Recurring Capital Cost
4. Administration	24,631	2% of Total and Recurring Capital Cost
Annualized Capital Costs	81,562	
Annualized Recurring Capital Costs	215,997	
TOTAL ANNUALIZED COSTS	508,156	Sum of Operating and Maintenance and Annualized Capital Costs

Note: All calculations using machine performance were based on operating conditions.Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,
2. The economic impacts are significant (i.e., an annualized cost of almost one-half million dollars, with a cost effectiveness of almost $2,000/ton of CO removed), and
3. Actual CO emissions are expected to be one-half or less than those proposed. The proposed level is based on the lack of operating experience with the LM 6000 in industrial applications.

4.3.2 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emission level is exceeded for PM10 and As, requiring PSD review (including BACT) for these pollutants. The emission of particulates from the CTs is a result of incomplete combustion and trace solids in the fuel (particularly fuel oil) and in the injected water or steam used for NO_x control. The design of the CTs ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on oil- or gas-fueled CTs. The No. 2 (i.e. distillate) fuel oil to be used in the CTs will contain only trace quantities of particulate (i.e., typically about 0.05 percent ash or less in fuel oil).

The maximum particulate emissions from the CTs when burning fuel oil will be a lower concentration than that normally specified for fabric filter designs; i.e., the grain loading associated with the maximum particulate emissions [about 15 pounds per hour (lb/hr)] is less than 0.01 grains per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

Therefore, there are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Levels of trace metals in distillate oil are limited by fuel oil specifications. Natural gas and distillate oil represents BACT for this pollutant.

For the nonregulated pollutants, most of which are trace metals, none of the control technologies evaluated for other pollutants (i.e., oxidation catalyst) would reduce such emissions; thus, natural gas and low sulfur distillate oil represent BACT because of their inherent low metals content.

5.0 AIR QUALITY MONITORING DATA

5.1 PSD PRECONSTRUCTION

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source or major modification is constructed. This analysis may be performed by the use of modeling and/or by monitoring the air quality. The use of monitoring data refers to either the use of representative air quality data from existing monitoring stations or establishing a monitoring network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year prior to submission of a construction permit application. In addition to establishing existing air quality, the air quality data are useful for determining background concentrations (i.e., concentrations from sources not considered in the modeling). The background concentrations can be added to the concentrations predicted for the sources considered in the modeling to estimate total air quality impacts. These total concentrations are then evaluated to determine compliance with the AAQS.

For the criteria pollutants, continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. However, preconstruction monitoring data generally will not be required if the ambient air quality concentration before construction is less than the de minimis impact monitoring concentrations (refer to Table 3-2 for de minimis impact levels). Also, if the maximum predicted impact of the source or modification is less than the de minimis impact monitoring concentrations, the source generally would be exempt from preconstruction monitoring.

For noncriteria pollutants, EPA recommends that an analysis based on air quality modeling generally should be used instead of monitoring data. The permit-granting authority has discretion in requiring preconstruction monitoring data when:

1. The state has an air quality standard for the noncriteria pollutant, and emissions from the source or modification pose a threat to the standard;
2. The reliability of emission data used as input to modeling existing sources is highly questionable; or
3. Air quality models have not been validated or may be suspect for certain situations, such as complex terrain or building downwash conditions.

However, if the maximum concentrations from the major source or major modification are predicted to be above the significant monitoring concentrations, EPA recommends that an EPA-approved measurement method be available before a permit-granting authority requires preconstruction monitoring.

EPA's Ambient Monitoring Guidelines for PSD (EPA, 1987a) sets forth guidelines for preconstruction monitoring. The guidelines allow the use of existing air quality data in lieu of additional air monitoring if the existing data are representative. The criteria used in determining the representativeness of data are monitor location, quality of data, and currentness of data.

For the first criterion, monitor location, the existing monitoring data should be representative of three types of areas:

1. The location(s) of maximum concentration increase from the proposed source or modification;
2. The location(s) of the maximum air pollutant concentration from existing sources; and
3. The location(s) of the maximum impact area (i.e., where the maximum pollutant concentration hypothetically would occur, based on the combined effect of existing sources and the proposed new source or modification).

Basically, the locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources.

For the second criteria, data quality, the monitoring data should be of similar quality as would be obtained if the applicant were monitoring according to PSD requirements. As a minimum, this would mean:

1. Use of continuous instrumentation,
2. Production of quality control records that indicate the instruments' operations and performances,
3. Operation of the instruments to satisfy quality assurance requirements, and
4. Data recovery of at least 80 percent of the data possible during the monitoring effort.

For the third criteria, currentness of data, the monitoring data must have been collected within a 3-year period preceding the submittal of permit application and must still be representative of current conditions.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for PM10, CO, and As emissions. As may be exempt from monitoring requirements because no acceptable monitoring technique has been established for that pollutant. The maximum predicted impacts from the proposed turbines also are less than de minimis levels for PM10 and CO. Therefore, preconstruction monitoring is not required for those pollutants for this project.

6.0 AIR QUALITY MODELING APPROACH

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

The general modeling approach follows EPA and FDER modeling guidelines. The highest predicted concentrations are compared with both PSD significant impact levels and de minimis air quality levels. If a facility exceeds the significant impact level for a particulate pollutant, current policies stipulate that the highest annual average and HSH short-term (i.e., 24 hours or less) concentrations be compared with AAQS and PSD increments when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations.

Concentrations for the screening phase were predicted using a coarse receptor grid and a 5-year meteorological record. After a final list of maximum short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the HSH concentration from the screening phase was produced. The air dispersion model then was executed for the entire year during which HSH concentrations were predicted. This approach was used to ensure that valid HSH concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the plant site. Within 50 km of the site, the terrain can be described as mostly simple (i.e., flat to gently rolling). As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. There are some areas with 5 km from the stack where the terrain rises up to 10 ft above the effective stack height. This terrain would be considered marginally intermediate terrain. However, because the terrain rises no higher than this height, which is well below the stable plume elevation (approximately 380 ft) a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex (ISC) dispersion model (EPA, 1988a) was selected to evaluate the pollutant emissions from the proposed unit and other modeled sources. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes that are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISC short-term (ISCST) model, is an extended version of the single-source (CRSTER) model (EPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term, and annual averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code within the ISC model is the ISC long-term (ISCLT) model. The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST model are presented in Table 6-1. Concentrations caused by stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options that affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area

Table 6-1. Major Features of the ISCST Model

ISCST Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
• Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple-point sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, and area sources
• Capability to calculate dry deposition
• Variation with height of wind speed (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average
• Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
• Receptors located above local terrain (i.e., "flagpole" receptors)
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing
• Wind speeds less than 1 m/s are set to 1 m/s.

Source: EPA, 1990.

within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50 percent for every 4 hours of plume travel time).

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility and discussions with FDER, the rural mode was selected because of the lack of residential, industrial, and commercial development within 3 km of the plant site.

6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Jacksonville International Airport and Waycross, Georgia, respectively. The 5-year period of meteorological data was from 1983 through 1987. The NWS station in Jacksonville is the nearest weather station which routinely records the hourly surface data required by the air dispersion models. The station is more than 20 miles inland from the Atlantic Ocean and, similar to Alachua County, is not significantly

$$M_w = \frac{\pi W^2}{4}$$

$$M_w = 0.8886\ W$$

where: M_w is input to the model to produce a building width of W used in the dispersion calculation. W is the actual building width.

The building structures considered in the modeling analysis are presented in Table 6-2. A site location map showing the location of these structures is presented in Figure 6-1.

Building dimensions for the proposed cogeneration plant and the existing heat plant were supplied by FPC and Energy Services, Inc. The dimensions of UF structures in the vicinity of the proposed plant site were obtained from maps made available by the Physical Plant Division at UF. Information on the J. Hillis Miller Health Center buildings was obtained from a map from the Department of General Services at UF.

All buildings that are closer than five times their height or maximum width (whichever is less) are considered to be within the zone of influence of the proposed facility and must then be incorporated in the modeling.

The following buildings at UF were analyzed and found to be outside the zone of influence of the proposed cogeneration facility:

1. The Health Science Center-Dentistry Department,
2. The Health Science Center-Veterinary Medicine Department,
3. Black Hall,
4. East and West Parking Garages to southeast of plant,
5. The existing UF Heat Plant No. 2, and
6. The proposed Ambulatory Center.

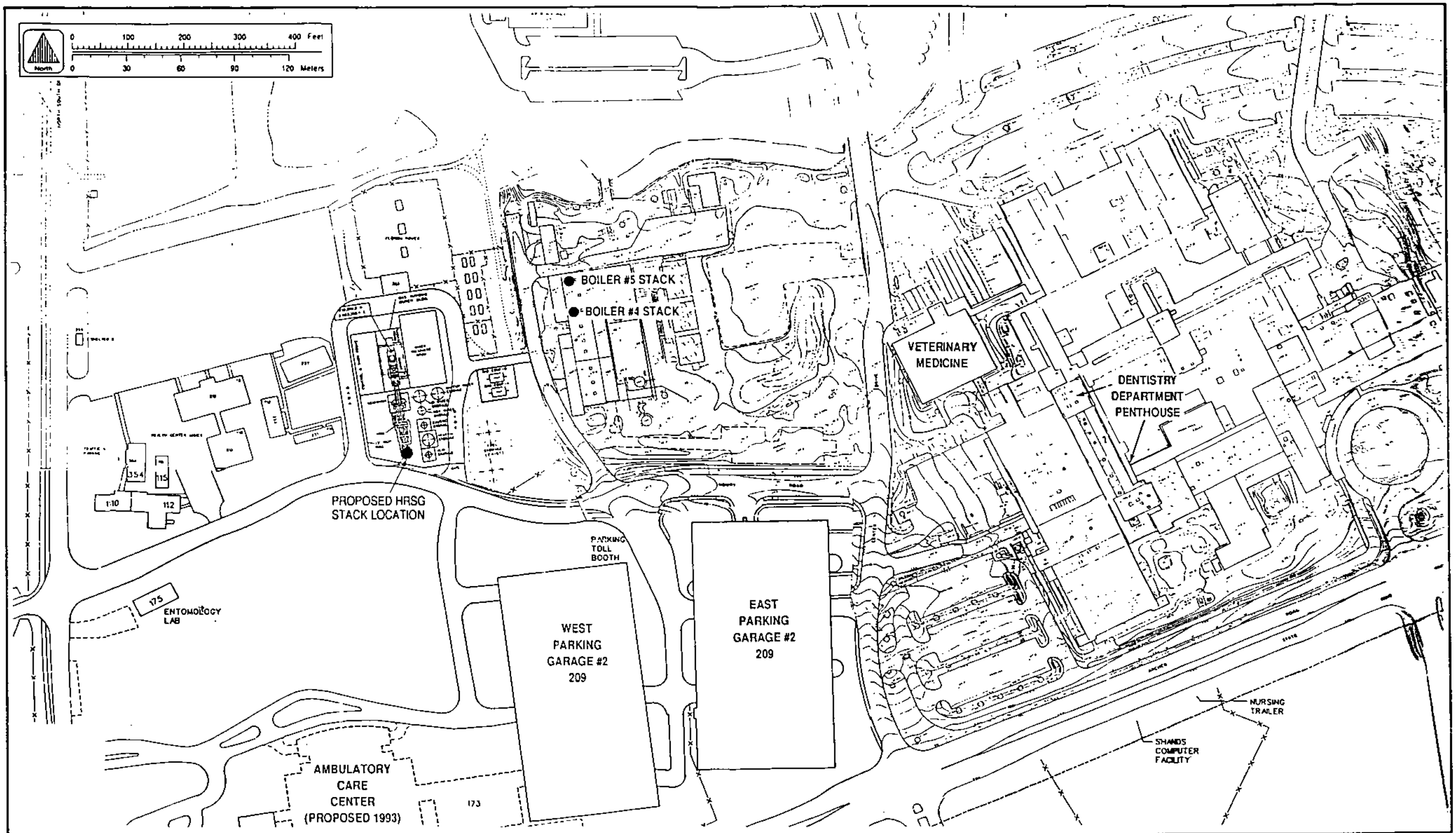

Figure 6-1 SITE AREA MAP INDICATING ALL BUILDING STRUCTURES CONSIDERED IN THE MODELING ANALYSIS

KBN

The proposed HRSG building is the dominant structure for the HRSG stack that was within the zone of influence. The dimensions of the HRSG are 57 ft high and 54 by 14 ft horizontally. The maximum projected width (MPW x 0.886) is 49.4 ft. Direction-specific building directions were not required for modeling this source.

Table 6-2. Building Structures Considered in the Modeling Analysis

Structure	Height[a] (ft)	Diagonal (ft)	Distance to Stacks (ft) HRSG	Units 4 and 5
HRSG Boiler Building	57	55.8	0	300[b]
UF Heating Plant Building	41.6	257	300[b]	0
UF Health Center				
Dentistry Department (Penthouse)	143	270	1080[b]	820[b]
Veterinary Medicine Building	59	180	845[b]	550[b]
West Parking Garage	65	480	340[b]	440[b]
East Parking Garage	65	480	510[b]	420[b]
Ambulatory Care Center (Proposed 1993)				
8th floor level	80[c]	143	580[b]	860[b]
9th floor level	90[c]	89	580[b]	860[b]
10th floor level	100[c]	66	580[b]	860[b]
University of Florida				
Black Hall	63	145	720[b]	440[b]

Note: ft = feet.
HRSG = heat recovery steam generators.
UF = University of Florida.

[a]Above mean grade level.
[b]Stack is beyond the downwash zone of influence of this structure.
[c]Estimate.

7.0 AIR QUALITY MODELING RESULTS

7.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the maximum concentrations as a result of the proposed turbine operating at maximum load conditions is presented in Table 7-1. Table 7-1 indicates the maximum screening concentrations for each year and averaging time with an emission rate of 10 g/s. Based on the results in Table 7-1, refined modeling was performed. The results of the refined modeling are presented in Table 7-2, including receptor location and the day and period of the maximum impacts. The maximum pollutant-specific concentrations for PM and CO were determined from the maximum generic impacts and are presented in Table 7-3.

The maximum predicted 1-hour and 8-hour CO concentrations are 250.0 and 58.7 $\mu g/m^3$, respectively. Because these concentrations are below the PSD significant levels of 2,000 and 500 $\mu g/m^3$, additional modeling is not necessary for CO.

The maximum predicted annual and 24-hour average PM10 concentrations when firing oil only are 0.12 and 4.63 $\mu g/m^3$, respectively. With the primary fuel, natural gas, the maximum impacts are 0.06 and 2.22 $\mu g/m^3$ for the annual and 24-hour averaging times, respectively. These maximum impacts are less than the PM10 significance impact levels. Therefore, additional modeling is not required for this pollutant.

7.2 TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility (see Table 3-3) are presented in Table 7-4. Inorganic arsenic is the only pollutant to be addressed and is compared in the table to the FDER No Threat Levels (NTL). The maximum 8-hour, 24-hour, and annual impacts for arsenic are well below the NTL for each respective averaging time.

Table 7-1. Maximum Predicted Impacts for the UF Cogeneration Facility Using a Generic Emission Rate of 10 Grams Per Second--Screening Analysis (Page 1 of 2)

Averaging Time	Year	Concentration (μg/m3)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Day/ Period
Annual					
	1983	0.85	220	70	- / -
	1984	0.53	220	70	- / -
	1985	0.72	230	70	- / -
	1986	0.54	230	70	- / -
	1987	0.99	120	70	- / -
1-Hour[b]					
	1983	135.31	40	100	92/16
	1984	110.53	80	70	244/23
	1985	162.96	130	70	45/23
	1986	131.36	120	70	27/12
	1987	99.60	120	70	23/ 2
3-Hour[b]					
	1983	73.04	220	70	44/ 5
	1984	83.44	60	70	88/ 6
	1985	62.31	110	70	359/ 4
	1986	57.87	230	70	81/ 5
	1987	54.57	120	70	363/ 1
8-Hour[b]					
	1983	44.86	220	70	44/ 2
	1984	42.19	60	70	88/ 3
	1985	40.49	100	70	43/ 1
	1986	42.44	120	70	27/ 2
	1987	39.46	110	70	338/ 2

Table 7-1. Maximum Predicted Impacts for the UF Cogeneration Facility Using a Generic Emission Rate of 10 Grams Per Second--Screening Analysis (Page 2 of 2)

Averaging Time	Year	Concentration ($\mu g/m3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Day/ Period
24-Hour[b]					
	1983	36.07	220	70	44/ 1
	1984	27.95	60	70	88/ 1
	1985	28.49	100	70	43/ 1
	1986	21.88	120	70	27/ 1
	1987	19.78	130	70	11/ 1

Note: $\mu g/m^3$ = micrograms per cubic meter
m = meter

[a] Relative to the location of the proposed unit.
[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 7-2. Maximum Predicted Impacts for the UF Cogeneration Facility Using a Generic Emission Rate of 10 Grams Per Second--Refined Analysis

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Day/ Period
Annual					
	1987	0.99	122	70	
1-Hour[b]					
	1985	203.3	128	70	45/23
3-Hour[b]					
	1984	83.44	60	70	88/6
8-Hour[b]					
	1983	47.75	218	70	44/2
	1984	47.59	56	70	88/2
	1986	44.60	118	70	27/2
24-Hour[b]					
	1983	36.71	218	70	44/1

Note: $\mu g/m^3$ = micrograms per cubic meter
m = meter

[a]Relative to the location of the proposed unit.
[b]All short-term concentrations indicate highest predicted concentrations.

Table 7-3. Maximum Predicted Pollutant Impacts of the UF Cogeneration Facility Compared to PSD Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
Particulate	Annual	10[a]	0.99	0.12 (0.06)	1
Matter (PM10)	24-Hour	(4.8)[b]	36.7	4.63 (2.22)	5
Carbon	1-Hour	70.5[a]	203.3	180.6 (250.0)	2,000
Monoxide	8-Hour	(97.6)[b]	47.75	42.4 (58.7)	500

Note: Short-term maximum impacts are highest predicted concentrations for 1983-87.

lb/hr = pounds per hour
$\mu g/m^3$ = micrograms per cubic meter

[a] Emission rate for firing oil, which will be used up to 438 hours per year and only during natural gas curtailments.

[b] Emission rate for the turbine and duct burner firing natural gas, the primary fuel. Impacts for natural gas shown in parentheses.

Table 7-4. Predicted Maximum Impacts of Toxic Pollutants for the UF Cogeneration Facility

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	No Threat Levels ($\mu g/m^3$)
<u>Non-Regulated</u>					
Inorganic Arsenic	8-Hour	1.5×10^{-4} [a]	47.75	0.00009	0.50
	24-Hour		36.7	0.00007	0.48
	Annual		0.99	0.000002	2.3×10^{-4}

Note: Short-term generic impacts are highest predicted concentrations for 1983-1987.

lb/hr = pounds per hour
$\mu g/m^3$ = micrograms per cubic meter

[a]Based on total TPY.

7.3 ADDITIONAL IMPACT ANALYSIS

7.3.1 IMPACTS UPON SOILS AND VEGETATION

Predicted impacts of all regulated pollutants are less than the significant impact levels (see Table 7-3). As a result, no impacts are expected to occur to soils or vegetation as a result of the proposed emissions of other regulated pollutants.

7.3.2 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel may be added to the current plant personnel. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in UF.

7.3.3 IMPACTS TO VISIBILITY

The plant is located approximately 125 km from the Chassahowitzka Wilderness Area, a PSD Class I area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were calculated for particulates and nitrogen oxides (as nitrogen dioxide). The results of the screening analysis are presented in Table 7-5. Based on the results, the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-5. Visibility Analysis for the UF Cogeneration Facility

Visual Effects Screening Analysis for
Source: UF COGENERATION FACILITY
Class I Area: CHASSAHOWITZKA WILDERNESS
*** Level-1 Screening ***

Input Emissions for

Particulates	17.00	TON/YR
NOx (as NO2)	38.80	TON/YR
Primary NO2	.00	TON/YR
Soot	.00	TON/YR
Primary SO4	.00	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	125.00 km
Min. Source-Class I Distance:	125.00 km
Max. Source-Class I Distance:	135.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	125.0	84.	2.00	.001	.05	.000
SKY	140.	84.	125.0	84.	2.00	.000	.05	.000
TERRAIN	10.	85.	125.3	84.	2.00	.000	.05	.000
TERRAIN	140.	85.	125.3	84.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	121.0	94.	2.00	.001	.05	.000
SKY	140.	75.	121.0	94.	2.00	.000	.05	.000
TERRAIN	10.	55.	111.9	114.	2.00	.000	.05	.000
TERRAIN	140.	55.	111.9	114.	2.00	.000	.05	.000

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APPENDIX A

Table A-1. Design Information and Stack Parameters for University of Florida Cogeneration Project

Data A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
General:			
Power (kW)	43,262.0	η = 42.5% NA	43,098.0
Heat Rate (Btu/kwh)	8,043.0	NA	8,877.0
Heat Input (mmBtu/hr)	348.0	187.0 ~50% of heat input	382.6
Fuel Oil (lb/hr)	18,313.5	9,842.1	20,792.4
(cf/hr)	367,818.5	197,674.4	
Fuel:			
Heat Content - (LHV)	19,000 Btu/lb	19,000 Btu/lb	18,400 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	0.5
CT Exhaust:			
Volume Flow (acfm)	564,678		569,684
Volume Flow (scfm)	239,478		235,916
Mass Flow (lb/hr)	1,036,522		1,030,290
Temperature (°F)	785		815
Moisture (% Vol.)	11.25		8.54
Oxygen (% Vol.)	13.73		13.60
Molecular Weight	27.80		28.05
Steam Injected (lb/hr)	31,402		22,504
HRSG Stack:			
Volume Flow (acfm)	325,200		320,364
Temperature (°F)	257		257
Diameter (ft)	9.75		9.78
Velocity (ft/sec)	72.59		71.51

Source: General Electric and Stewart and Stevenson, 1991.

Note: All data shown on this table and subsequent tables are for the combustion turbine and duct burner.

Table A-2. Maximum Criteria Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
<u>Particulate:</u>			
Basis	Manufacturer	0.01 lb/mmBtu	Manufacturer
lb/hr	2.50	1.87	10.0
TPY	10.95	7.37	2.2
<u>Sulfur Dioxide:</u>			
Basis	1 gr/100 cf	1 gr/100 cf	0.5 % Sulfur
lb/hr	1.05	0.56	197.53
TPY	4.60	2.23	43.3
<u>Nitrogen Oxides:</u>			
Basis	25 ppm*	0.1 lb/mmBtu	42 ppm*
lb/hr	35.0	18.7	66.3
TPY	153.4	73.72	14.5
ppm	25.0	NA	42.0
<u>Carbon Monoxide:</u>			
Basis	75 ppm+	0.15 lb/mmBtu	75 ppm+
lb/hr	69.5	28.1	70.5
TPY	304.37	110.57	15.4
ppm	75.0	NA	75.0
<u>VOC's:</u>			
Basis	4 ppm+	0.043 lb/mmBtu	10 ppm+
lb/hr	1.59	8.04	4.03
TPY	7.0	31.70	0.9
ppm	4.0	NA	10.0
<u>Lead:</u>			
Basis			EPA(1988)
lb/hr	NA	NA	3.40E-03
TPY	NA	NA	7.46E-04

[a]Corrected to 15% 02 dry conditions.
[b]Corrected to dry conditions.

Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr and 415 hrs/yr for fuel oil firing. Annual emissions for duct burners on 7,884 hrs/yr (90% capacity factor).

Table A-3. Maximum Other Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
As (lb/hr)	NEG.	NEG.	0.00160684
(TPY)	NEG.	NEG.	3.52E-04
Be (lb/hr)	NEG.	NEG.	0.0009564524
(TPY)	NEG.	NEG.	2.09E-04
Hg (lb/hr)	NEG.	NEG.	1.15E-03
(TPY)	NEG.	NEG.	2.51E-04
F (lb/hr)	NEG.	NEG.	0.0124338807
(TPY)	NEG.	NEG.	2.72E-03
H2SO4 (lb/hr)	8.04E-03	4.32E-03	1.59E+01
(TPY)	3.52E-02	0.02	3.48E+00

Sources: EPA, 1988; EPA, 1980.

Table A-4. Maximum Non-Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Manganese (lb/hr)	NEG.	NEG.	2.46E-03
(TPY)	NEG.	NEG.	5.40E-04
Nickel (lb/hr)	NEG.	NEG.	6.50E-02
(TPY)	NEG.	NEG.	1.42E-02
Cadmium (lb/hr)	NEG.	NEG.	4.02E-03
(TPY)	NEG.	NEG.	8.80E-04
Chromium (lb/hr)	NEG.	NEG.	1.82E-02
(TPY)	NEG.	NEG.	3.98E-03
Copper (lb/hr)	NEG.	NEG.	1.07E-01
(TPY)	NEG.	NEG.	2.35E-02
Vanadium (lb/hr)	NEG.	NEG.	2.67E-02
(TPY)	NEG.	NEG.	5.84E-03
Selenium (lb/hr)	NEG.	NEG.	8.98E-03
(TPY)	NEG.	NEG.	1.97E-03
POM (lb/hr)	3.88E-04	2.09E-04	1.07E-04
(TPY)	1.70E-03	8.22E-04	2.34E-05
Formaldehyde (lb/hr)	3.07E-02	7.57E-02	1.55E-01
(TPY)	1.35E-01	2.99E-01	3.39E-02

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Antimony (lb/hr)	NEG.	NEG.	8.36E-03
(TPY)	NEG.	NEG.	1.83E-03
Barium (lb/hr)	NEG.	NEG.	7.47E-03
(TPY)	NEG.	NEG.	1.64E-03
Colbalt (lb/hr)	NEG.	NEG.	3.47E-03
(TPY)	NEG.	NEG.	7.59E-04
Zinc (lb/hr)	NEG.	NEG.	2.61E-01
(TPY)	NEG.	NEG.	5.72E-02
Chlorine[a] (lb/hr)	NEG.	NEG.	1.04E-02
(TPY)	NEG.	NEG.	2.28E-03

Source: EPA, 1979

[a]Assumes 0.5 ppm in fuel oil.

EMISSION FACTORS AND CALCULATIONS

Emission factors used in the calculations were obtained from the following sources (references attached):

1. Compilation of air pollutant emiission factors (AP-42) for PM, SO_2, NO_x, CO, and VOC.

2. Estimating air toxics from coal and oil combustion sources (EPA, 1989) for As, Be, Pb, and Hg.

3. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources (EPA, 1981) for F.

The conversions from $lb/10^{-12}$ Btu to $lb/10^3$ gal were calculated as follows:

Residual Oil = EF $lb/10^{12}$ Btu * 18,300 Btu/lb oil * 8.2 lb oil/gal

$* 1{,}000/10^3 = 1.5 \times 10^{-4} *$ EF $lb/10^3$ gal

where: EF = emission factor

Distillate Oil = EF $lb/10^{12}$ Btu * 20,996/lb oil * 7.2 lb/gal

$* 1{,}000/10^3 = 1.512 \times 10^{-4} *$ EF $lb/10^3$ gal

The conversion from pg/J to $lb/10^{12}$ Btu is as follows:

pg/J * 10^{-12} g/pg * lb/454 grams * 1,055 J/Btu = 2.324 $lb/10^{12}$ Btu

A

Volume is calculated based on ideal gas law:

PV = mRT/M
V = mRT/(MP) for natural gas

where:
P = pressure = 2116.8 lb/ft^2
m = mass flow of gas (lb/hr)
R = universal gas constant = 1545 ft-lb/lb-mole °R
M = molecular weight of gas
T = temperature (K)

B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

C

CO and VOC are calculated by correcting for moisture using ideal gas law. Same as NO_x calculation except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO}\ /\ RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT$$

pg/J = picograms per joule

AP-42
SUPPLEMENT C
SEPTEMBER 1990

SUPPLEMENT C

TO

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace size & type (10^6 Btu/hr heat input)	Particulate[b]		Sulfur dioxide[c]		Nitrogen oxides[d]		Carbon monoxide[e]		Volatile organics			
									Nonmethane		Methane	
	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$
Utility boilers (> 100)	16 - 80	1 - 5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16 - 80	1 - 5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (< 10)	16 - 80	1 - 5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a]Expressed as weight/volume fuel fired.
[b]References 15-18.
[c]Reference 4. Based on avg. sulfur content of natural gas, 4600 $g/10^6 Nm^3$ (2000 $gr/10^6$ scf).
[d]References 4-5, 7-8, 11, 14, 18-19, 21.
[e]Expressed as NO_2. Tests indicate about 95 weight % NO_x is NO_2.
[f]References 4, 7-8, 16, 18, 22-25.
[g]References 16, 18. May increase 10 - 100 times with improper operation or maintenance.
[h]For tangentially fired units, use 4400 $kg/10^6 m^3$ (275 $lb/10^6 ft^3$). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. For potential NO_x reductions by combustion modification, see text. Note that NO_x reduction from these modifications will also occur at reduced load conditions.

~ Rough Ave reduction

Retired units: 140 $Lbs_{NOx}/10^6 Ft^3_{gas}$ × ~Ave 100,000 Ft^3/hr × ~Ave 3,000 hr/YR × $\frac{Ton_{NOx}}{2000 Lbs_{NOx}}$ = 21 TPY

TABLE 1.3-1. UNCONTROLLED EMISSION FACTORS FOR FUEL OIL COMBUSTION

EMISSION FACTOR RATING: A

Boiler Type[a]	Particulate Matter[b]		Sulfur Dioxide[c]		Sulfur Trioxide		Carbon Monoxide[d]		Nitrogen Oxide[e]		Volatile Organics[f] Nonmethane		Volatile Organics[f] Methane	
	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$
Utility Boilers														
Residual Oil	g	g	19S	157S	0.34S[h]	2.9S[h]	0.6	5	8.0 (12.6)(5)[i]	67 (105)(42)[i]	0.09	0.76	0.03	0.28
Industrial Boilers														
Residual Oil	g	g	19S	157S	0.24S	2S	0.6	5	6.6[j]	55[j]	0.034	0.28	0.12	1.0
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.024	0.2	0.006	0.052
Commercial Boilers														
Residual Oil	g	g	19S	157S	0.24S	2S	0.6	5	6.6	55	0.14	1.13	0.057	0.475
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.04	0.34	0.026	0.216
Residential Furnaces														
Distillate Oil	0.3	2.5	17S	142S	0.24S	2S	0.6	5	2.2	18	0.085	0.713	0.214	1.78

[a] Boilers can be approximately classified according to their gross (higher) heat rate as shown below:
Utility (power plant) boilers: >106 x 10^9 J/hr (>100 x 10^6 Btu/hr)
Industrial boilers: 10.6 x 10^9 to 106 x 10^9 J/hr (10 x 10^6 to 100 x 10^6 Btu/hr)
Commercial boilers: 0.5 x 10^9 to 10.6 x 10^9 J/hr (0.5 x 10^6 to 10 x 10^6 Btu/hr)
Residential furnaces: <0.5 x 10^9 J/hr (<0.5 x 10^6 Btu/hr)

[b] References 3-7 and 24-25. Particulate matter is defined in this section as that material collected by EPA Method 5 (front half catch).

[c] References 1-5. S indicates that the weight % of sulfur in the oil should be multiplied by the value given.

[d] References 3-5 and 8-10. Carbon monoxide emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[e] Expressed as NO_2. References 1-5, 8-11, 17 and 26. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO.

[f] References 18-21. Volatile organic compound emissions are generally negligible unless boiler is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g] Particulate emission factors for residual oil combustion are, on average, a function of *fuel oil grade and sulfur content:*
Grade 6 oil: 1.25(S) + 0.38 kg/10^3 liter [10(S) + 3 lb/10^3 gal] where S is the weight % of sulfur in the oil. This relationship is based on 81 individual tests and has a correlation coefficient of 0.65.
Grade 5 oil: 1.25 kg/10^3 liter (10 lb/10^3 gal)
Grade 4 oil: 0.88 kg/10^3 liter (7 lb/10^3 gal)

[h] Reference 25.

[i] Use 5 kg/10^3 liters (42 lb/10^3 gal) for tangentially fired boilers, 12.6 kg/10^3 liters (105 lb/10^3gal) for vertical fired boilers, and 8.0 kg/10^3 liters (67 lb/10^3 gal) for all others, at full load and normal (>15%) excess air. Several combustion modifications can be employed for NO_x reduction: (1) limited excess air can reduce NO_x emissions 5-20%, (2) staged combustion 20-40%, (3) using low NO_x burners 20-50%, and (4) ammonia injection can reduce NO_x emissions 40-70% but may increase emissions of ammonia. Combinations of these modifications have been employed for further reductions in certain boilers. See Reference 23 for a discussion of these and other NO_x reducing techniques and their operational and environmental impacts.

[j] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content, estimated more accurately by the *empirical relationship:*
kg $NO_2/10^3$ liters = 2.75 + $50(N)^2$ [lb $NO_2/10^3$gal = 22 + $400(N)^2$] where N is the weight % of nitrogen in the oil. For residual oils having high (>0.5 weight %) nitrogen content, use 15 kg $NO_2/10^3$ liter (120 lb $NO_2/10^3$gal) as an emission factor.

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu)	
	Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

PB81-225559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
Element	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.8	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149
Iron (Fe)	363	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

Ave. 50.9

APPENDIX B

EXISTING PERMITS AND ANNUAL OPERATING REPORTS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

PERMITTEE:
University of Florida
Physical Plant Division
Bldg. 702; Room 110
Gainesville, FL 32611

I.D. Number:	31GVL01001402
Permit/Certification Number:	AO01-136997
Date of Issue:	October 12, 1987
Expiration Date:	August 1, 1992
County:	Alachua
Latitude/Longitude:	29°38'24"N; 82°20'52"W
Project:	No. 1 Steam Boiler at CHP
UTM:	E-(17)369.5; N-3279

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the operation of No. 1 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, FL.

In accordance with:

operation permit application dated August 23, 1977
renewal application dated June 21, 1982
renewal application dated July 17, 1987
BACT Determination received September 24, 1987.

PERMITTEE:
University of Florida at CHP
No. 1 Steam Boiler

Permit No.: A001-136997
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollutuion in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately notify and provide the Department with the following information:

a. a description of and cause of noncompliance; and

b. the period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.

c. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the Department, during the course of any unresolved enforcement action.

    b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

    - the date, exact place, and time of sampling or measurements;
    - the person responsible for performing the sampling or measurements;
    - the date(s) analyses were performed;
    - the person responsible for performing the analyses;
    - the analytical techniques or methods used; and
    - the results of such analyses.

15. When requested by the Department, the permittee shall, within a reasonable period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be submitted or corrected promptly.

PERMITTEE:
University of Florida at CHP
No. 1 Steam Boiler

Permit No.: A001-136997
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 84,320 CF/hr of natural gas or 533 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Rule	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	9.59[1]	38.38
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	132.72[2]	530.87
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr[4]	

[1]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; AP-42 emission factor.

[2]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; 8.3 [3]lbs/gal.

[3]Basis: 08-23-77 application

[4]Basis: Bact Determination dated 09-21-87 which limits the fuel oil fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

PERMITTEE:
University of Florida at CHP
No. 1 Steam Boiler

Permit No.: A001-136997
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* 14 days prior to testing, and submit the test report documentation to the GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months - send certified fuel oil analysis with the annual operation report if this unit is fired with No. 6 oil for more than 400 hr. the previous calendar year.
VE	12 months[1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified.

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours.

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report.

*Gainesville Branch Office (GBO) located at 5700 SW 34th St., Suite 1204, Gainesville, FL 32608. Phone 904/377-7528.

Tests and test reports shall comply with the requirements of Florida Administrative Code Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for renewal will be sent 5 months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992.

Issued this 12 day of October, 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

BFW

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions : Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

PERMITTEE:
University of Florida
Physical Plant Division
Bldg. 702; Room 110
Gainesville, FL 32611

I.D. Number:	31GVL01001403
Permit/Certification Number:	AO01-136998
Date of Issue:	October 12, 1987
Expiration Date:	August 1, 1992
County:	Alachua
Latitude/Longitude:	29°38'24"N; 82°20'52"W
Project:	No. 2 Steam Boiler at CHP
UTM:	E-(17)369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the operation of No. 2 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, FL.

In accordance with:

operation permit application dated August 23, 1977
renewal application dated June 21, 1982
renewal application dated July 17, 1987
BACT Determination received September 24, 1987.

PERMITTEE:
University of Florida at CHP
No. 2 Steam Boiler

Permit No.: A001-136998
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollutuion in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately notify and provide the Department with the following information:

   a. a description of and cause of noncompliance; and

   b. the period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.

   c. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

   ( ) Determination of Best Available Control Technology (BACT)
   ( ) Determination of Prevention of Significant Deterioration (PSD)
   ( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
   ( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

 a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the Department, during the course of any unresolved enforcement action.

 b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

 c. Records of monitoring information shall include:

 - the date, exact place, and time of sampling or measurements;
 - the person responsible for performing the sampling or measurements;
 - the date(s) analyses were performed;
 - the person responsible for performing the analyses;
 - the analytical techniques or methods used; and
 - the results of such analyses.

15. When requested by the Department, the permittee shall, within a reasonable period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be submitted or corrected promptly.

PERMITTEE:
University of Florida at CHP
No. 2 Steam Boiler

Permit No.: A001-136998
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 84,320 CF/hr of natural gas or 533 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No.1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Rule	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	9.59[1]	38.38
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	132.72[2]	530.87
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr	

[1]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; AP-42 emission factor.

[2]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; 8.3 [3]lbs/gal.

[3]Basis: 08-23-77 application

[4]Basis: Bact Determination dated 09-21-87 which limits the fuel oil fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* 14 days prior to testing, and submit the test report documentation to the GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months - send certified fuel oil analysis with the annual operation report if this unit is fired with No. 6 oil for more than 400 hr. the previous calendar year.
VE	12 months[1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified.

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours.

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report.

*Gainesville Branch Office (GBO) located at 5700 SW 34th St., Suite 1204, Gainesville, FL 32608. Phone 904/377-7528.

Tests and test reports shall comply with the requirements of Florida Administrative Code Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for renewal will be sent 5 months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992.

Issued this 12 day of October, 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

affected by diurnal land-sea breezes. Therefore, these data are considered to be the most representative of weather conditions occurring at the plant site.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program (RAMMET) to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Waycross using the Holzworth approach (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the RAMMET meteorological preprocessor program.

6.3 EMISSION INVENTORY

Stack operating parameters and air emission rates for the proposed unit were presented in Section 2.0.

Modeling of the proposed unit demonstrated that the facility's PM10 and CO impacts are below the significant impact levels. Further modeling for this facility is not required.

6.4 RECEPTOR LOCATIONS

In the ISCST modeling, concentrations were predicted for the screening phase using a polar receptor grid. A description of the receptor locations for determining maximum predicted impacts is as follows:

The receptor grid for the short-term CO modeling included rings at 53; 70; 100; 400; 700; 1,000; 1,300; 1,600; 2,000; and 2,500 meters. The 53-meter distance is the closest allowable ring distance (3 x building height) for assessing the impacts due to building wake effects. Elevations of 77 and 85 ft were chosen for all receptors at 53 and 70 meters, respectively. These elevations are representative of the highest terrain near the site.

After the screening modeling was completed, refined modeling was conducted using a receptor grid centered on the receptor that had the highest concentration from the screening analysis. The receptors were located at intervals of 100 m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments, centered on the radial along which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90-degree radial at a distance of 1.6 km, the refined receptor grid would consist of receptors at the following locations:

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	1.3, 1.4, 1.5, 1.6, 1.7, 1.8, and 1.9 per direction

To ensure that a valid maximum concentration was calculated, concentrations were predicted using the refined grid for the entire year that produced the highest concentration from the screening receptor grid. If maximum concentrations for other years were within 10 percent of that for the highest year, they also were refined.

Refined modeling analysis was not performed for the annual averaging period because the spatial distribution of annual average concentrations are not expected to vary significantly from those produced from the screening analysis.

The minimum distance of the proposed source from the Chassahowitzka Wilderness Area is approximately 125 km. Since the impacts of this source are below significant impact levels, impacts at the PSD Class I area were not performed.

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stack for the proposed turbine will be less than GEP. Therefore, the potential for building downwash to occur was considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than H_b + 0-5 L_b, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than $H_b + 0.5\ L_b$ but less than GEP, the Huber-Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. If a specific width is to be modeled, then the value input to the model must be adjusted according to the following formula:

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

1/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

PERMITTEE:
University of Florida
Physical Plant Division
Bldg. 702; Room 110
Gainesville, FL 32611

I.D. Number:	31GVL01001404
Permit/Certification Number:	AO01-136999
Date of Issue:	October 12, 1987
Expiration Date:	August 1, 1992
County:	Alachua
Latitude/Longitude:	29°38'24"N; 82°20'52"W
Project:	No. 3 Steam Boiler at CHP
UTM:	E-(17)369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the operation of No. 3 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, FL.

In accordance with:

operation permit application dated August 23, 1977
renewal application dated June 21, 1982
renewal application dated July 17, 1987
BACT Determination received September 24, 1987.

PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollutuion in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately notify and provide the Department with the following information:

   a. a description of and cause of noncompliance; and

   b. the period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.

   c. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

   ( ) Determination of Best Available Control Technology (BACT)
   ( ) Determination of Prevention of Significant Deterioration (PSD)
   ( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
   ( ) Compliance with New Source Performance Standards

PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

14. The permittee shall comply with the following monitoring and record keeping requirements:

   a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the Department, during the course of any unresolved enforcement action.

   b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

   c. Records of monitoring information shall include:

      - the date, exact place, and time of sampling or measurements;
      - the person responsible for performing the sampling or measurements;
      - the date(s) analyses were performed;
      - the person responsible for performing the analyses;
      - the analytical techniques or methods used; and
      - the results of such analyses.

15. When requested by the Department, the permittee shall, within a reasonable period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be submitted or corrected promptly.

PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: AO01-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 153,000 CF/hr of natural gas or 1066.6 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Rule	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	19.20[1]	76.80
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	265.58[2]	1062.33
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr	

[1]Basis: 1066.6 [3]gals/hr; 1.5%[4] S in FO; AP-42 emission factor.

[2]Basis: 1066.6 [3]gals/hr; 1.5%[4] S in FO; 8.3 [3]lbs/gal.

[3]Basis: 08-23-77 application

[4]Basis: Bact Determination dated 09-21-87 which limits the fuel oil fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* 14 days prior to testing, and submit the test report documentation to the GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months - send certified fuel oil analysis with the annual operation report if this unit is fired with No. 6 oil for more than 400 hr. the previous calendar year.
VE	12 months[1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified.

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours.

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report.

*Gainesville Branch Office (GBO) located at 5700 SW 34th St., Suite 1204, Gainesville, FL 32608. Phone 904/377-7528.

Tests and test reports shall comply with the requirements of Florida Administrative Code Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for renewal will be sent 5 months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992.

Issued this 12 day of October, 1987

ffw STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/796-4200

PERMITTEE:

Mr. Ken Kisida, Utilities Manager
University of Florida
Physical Plant Division
Building 702, Room 110
Gainesville, Florida 32611

I.D. Number: 31GVL01001411
Permit/Cert Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992
County: Alachua
Lat/Long: 29°38'24"N/82°20'52"W
Section/Township/Range:
Project: No. 4 Steam Boiler at CHP
UTM: E-(17) 369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the operation of No. 4 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, Florida.

In accordance with operational permit application dated August 23, 1977, renewal application dated June 21, 1982, renewal application dated July 8, 1987 and BACT Datermination received September 24, 1987.

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants, or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and department rules, unless specifically authorized by an order from the department.

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with, or will be unable to comply with, any condition or limitation specified in this permit, the permittee shall immediately notify and provide the department with the following information:

a. A description of and cause of non-compliance; and

b. the period of non-compliance, including exact dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the department, may be used by the department as evidence in any enforcement case arising under the Florida Statutes or department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or department rules.

11. This permit is transferable only upon department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

PERMITTEE:

University of Florida
No. 4 Stem Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards
( ) (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the date(s) analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the department, the permittee shall, within a reasonable period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the department, such facts or information shall be submitted or corrected promptly.

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 68.333 cf/hr of natural gas or 444 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Regulation	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	7.99[1]	31.97
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	110.56[2]	442.23
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr	

[1]Basis: 444[3] gals/hr; 1.5%[4] S in FO; AP-42 emission factor

[2]Basis: 444[3] gals/hr; 1.5%[4] S in FO; 8.3[3] lbs/gal

[3]Basis: 08-23-77 application

[4]Basis: BACT determination dated September 21, 1987 which limits the fuel fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* fourteen (14) days prior to testing, and submit the test report documentations to GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months; Send certified fuel oil analysis with the annual opn rpt if this unit is fired with No. 6 oil for more than 400 hours the previous calendar year.

* GBO at 5700 S.W. 34th Street, Suite 1204, Gainesville, Florida 32608
Phone No. (904)377-7528

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

CONDITIONAL VE BASED ON FUEL USED

Pollutant	Interval from 01-20-87
VE	12 months [1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified
[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours
[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report

Tests and test reports shall comply with the requirements of FAC Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for the renewal will be sent five (5) months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992 .

Issued this 1st day of October 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	:	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual capacity, the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
SUITE ...
... BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

NORTHEAST DISTRICT

APPLICATION FOR RENEWAL OF PERMIT TO OPERATE AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: No. 4 Steam Boiler Renewal of DER Permit No. A001-57683

Company Name: UNIVERSITY of FLORIDA County: ALACHUA

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

No. 4 Steam Boiler Second Black Steel Stack From the North End of Plant

Source Location: Street: Bldg. 473 North of Mowery ROAD City: GAINESVILLE

UTM: East ________ North ________

Latitude: __° __' __"N. Longitude: __° __' __"W.

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously.

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [ ] Yes [X] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate	lbs/hr

B. Product Weight (lbs/hr): 50,000

C. Fuels No. 6 Oil

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
No. 6 Fuel Oil		250 Gal	148,000 BTU per Gal, min

D. Normal Equipment Operating Time: hrs/day 24 ; days/wk _____ ; wks/yr _____ ;

hrs/yr (power plants only) _____ ; if seasonal, describe ______________________

____

____

The undersigned owner or authorized representative*** of ____________________ is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility.

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-lbs/hr.
***Attach letter of authorization if not previously submitted

Ken Kisida

Signature, Owner or Authorized Representative
(Notarization is mandatory)

Utilities Manager - Ken Kisida
Typed Name and Title

Physical Plant Division - Building 702 Room 110
Address

Gainesville, Florida 32611
City State Zip

July 8, 1987
Date

904-392-1157
Telephone No.

DER Form 17-1.202(4)
Effective November 30, 1982

Josephine E Trudell
7/8/87

Notary Public, State of Florida
My Commission Expires June 17, 1988
Bonded Thru Troy Fain Insurance, Inc.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

PERMITTEE:

Mr. Ken Kisida, Utilities Manager
University of Florida
Physical Plant Division
Building 702, Room 110
Gainesville, Florida 32611

I.D. Number: 31GVL01001415
Permit/Cert Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992
County: Alachua
Lat/Long: 29°38'24"N/82°20'52"W
Section/Township/Range:
Project: No. 5 Steam Boiler at CHP
UTM: E-(17)369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the operation of No.5 Steam Boiler at the Central Heal Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, Florida.

In accordance with operating permit application dated August 23, 1977, renewal application dated June 21, 1982, renewal application dated July 8, 1987 and BACT Determination received September 24, 1987.

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-1136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants, or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and department rules, unless specifically authorized by an order from the department.

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with, or will be unable to comply with, any condition or limitation specified in this permit, the permittee shall immediately notify and provide the department with the following information:

   a. A description of and cause of non-compliance; and

   b. the period of non-compliance, including exact dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the department, may be used by the department as evidence in any enforcement case arising under the Florida Statutes or department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or department rules.

11. This permit is transferable only upon department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards
( ) (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the date(s) analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the department, the permittee shall, within a reasonable period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the department, such facts or information shall be submitted or corrected promptly.

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 164,000 cf/hr of natural gas or 1066.6 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Regulation	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	19.20[1]	76.80
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	265.58[2]	1062.33
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr[4]	

[1]Basis: 1066.6[3] gals/hr; 1.5%[4] S in FO; AP-42 emission factor

[2]Basis: 1066.6[3] gals/hr; 1.5%[4] S in FO; 8.3[3] lbs/gal

[3]Basis: 08-23-77 application

[4]Basis: BACT determination dated September 21, 1987 which limits the fuel fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* fourteen (14) days prior to testing, and submit the test report documentations to GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months; Send certified fuel oil analysis with the annual opn rpt if this unit is fired with No. 6 oil for more than 400 hours the previous calendar year.

* GBO at 5700 S.W. 34th Street, Suite 1204, Gainesville, Florida 32608
Phone No. (904)377-7528

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

CONDITIONAL VE BASED ON FUEL USED

Pollutant	Interval from 01-20-87
VE	12 months [1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report

Tests and test reports shall comply with the requirements of FAC Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for the renewal will be sent five (5) months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992 .

Issued this 1st day of October 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977, and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual capacity, the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977, and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual capacity, the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
BILLS ROAD
JACKSONVILLE, FLORIDA 32207

NORTHEAST DISTRICT
RECEIVED
9 1987
DER - JACKSONVILLE

BOB GRAHAM
GOVERNOR
VICTORIA J. TSCHINKEL
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER

APPLICATION FOR RENEWAL OF PERMIT TO OPERATE AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: No. 5 Steam Boiler Renewal of DER Permit No. AO01-57683

Company Name: UNIVERSITY OF FLORIDA County: ALACHUA

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

Black Steel Stack North End of Plant No. 5 Steam Boiler

Source Location: Street: Bldg 473 North of Mowery Road City: Gainesville

UTM: East ______ North ______

Latitude: __ __° __ __' __ __"N. Longitude: __ __° __ __' __ __"W.

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [✓] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously.

4. Have previous permit conditions been adhered to? [✓] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [✓] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [✓] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [ ] Yes [✓] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr

B. Product Weight (lbs/hr): 120,000

C. Fuels No. 6 Oil

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
No. 6 Fuel Oil		600 GALS	149,000 BTU per GAL, Min

= 88 mmBTU/hr

D. Normal Equipment Operating Time: hrs/day 24; days/wk ____; wks/yr ____;

hrs/yr (power plants only) ____; if seasonal, describe ____

The undersigned owner or authorized representative*** of ____ is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility.

*During actual time of operation.

**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-lbs/hr.

***Attach letter of authorization if not previously submitted

Ken Kisida

Signature, Owner or Authorized Representative (Notarization is mandatory)

Utilities Manager - Ken Kisida

Typed Name and Title

Physical Plant Division - Building 702 Room 110

Address

Gainesville, Florida 32611

City State Zip

July 8, 1987

Date

904-392-1157

Telephone No.

Notary Public, State of Florida

My Commission Expires June 17, 1989

Bonded Thru Troy Fain - Insurance, Inc.

Josephine E. Tisdale

7/8/87

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 88 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div.; Bldg. 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack south end of Plant

II ACTUAL OPERATING HOURS: 1923.5 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

91372.0 10^6 cubic feet Natural Gas

N/A 10^3 gallons ________ Oil, ________ %S

________ 10^3 gallons Propane

________ 10^6 Black Liquor Solids

________ 10^3 Kerosene

________ tons Coal

________ tons Carbonaceous

________ tons Refuse

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

____
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

____
TYPED NAME AND TITLE

____
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
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DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473; Gainesville, Fl. 32611
4. Description of Source: Black steel stack second from south end of Plant

II ACTUAL OPERATING HOURS: 2892.0 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

84753.0 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________________________________ TYPED NAME AND TITLE

________________________________ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473
   Gainesville, Fl 32611
4. Description of Source: ______

II ACTUAL OPERATING HOURS: 4451.6 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

464,100 10^6 cubic feet Natural Gas	______ 10^3 Kerosene
26,268 10^3 gallons 6 Oil, 2 %S	______ tons Coal
______ 10^3 gallons Propane	______ tons Carbonaceous
______ 10^6 Black Liquor Solids	______ tons Refuse

Other (Specify type and units) ______

VI **EMISSION RATE(S)** (tons/yr)

______ Particulates	______ Sulfur Dioxide	______ Total Reduced Sulfur
______ Nitrogen Oxide	______ Carbon Monoxide	______ Fluoride
______ Hydrocarbon	Other (Specify type and units) ______	

VII **METHOD OF CALCULATING EMISSION RATES** (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-min. average was 4.3 percent.

VIII **CERTIFICATION:**

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 88 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473
   Gainesville
4. Description of Source: Black steel stack second from North end.

II ACTUAL OPERATING HOURS: 3992.1 hrs/day ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

1[illegible]9,651	10^6 cubic feet Natural Gas	______	10^3 Kerosene
40,772	10^3 gallons 6 Oil, 2 %S	______	tons Coal
______	10^3 gallons Propane	______	tons Carbonaceous
______	10^6 Black Liquor Solids	______	tons Refuse

Other (Specify type and units) ______________________

EMISSION RATE(S) (tons/yr)

______	Particulates	______	Sulfur Dioxide	______	Total Reduced Sulfur
______	Nitrogen Oxide	______	Carbon Monoxide	______	Fluoride
______	Hydrocarbon		Other (Specify type and units) ______		

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-min. average was .05 percent.

I CERTIFICATION:

ereby certify that the information given in this report is correct to the best of my wledge.

______________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______________________ TYPED NAME AND TITLE

______________________ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack on North end of Plant

II ACTUAL OPERATING HOURS: 6411 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

537.777 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

537.506 10^3 gallons 6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-min. average was 9.7 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE — TYPED NAME AND TITLE

____

DATE

Florida Department of Environmental Regulation

Twin Towers Office Bldg ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

DER Form #

Form Title

Effective Date

DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div.; Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack, south end of Plant

II ACTUAL OPERATING HOURS: 3989.0 hrs/day ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

158,848.0 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________ ________________
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____
DATE

Florida-Department of Environmental Regulation
Twin Towers Office Bldg ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 3125.8 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

Northwest District 160 Governmental Center Pensacola, Florida 32501-5794 904-436-8300
Northeast District 3426 Bills Rd Jacksonville, Florida 32207 904-798-4200
Central District 3319 Maguire Blvd, Suite 232 Orlando, Florida 32803-3767 407-894-7555
Southwest District 4520 Oak Fair Blvd Tampa, Florida 33610-7347 813-623-5561
South District 2269 Bay St Fort Myers, Florida 33901-2896 813-332-2667
Southeast District 1900 S Congress Ave, Suite West Palm Beach, Florida 33 407-964-9668

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

144,723.0	10^6 cubic feet Natural Gas	________	10^3 Kerosene
N/A	10^3 gallons ________ Oil, ________ %S	________	tons Coal
________	10^3 gallons Propane	________	tons Carbonaceous
________	10^6 Black Liquor Solids	________	tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE | TYPED NAME AND TITLE

____

DATE

Florida Department of Environmental Regulation

Twin Towers Office Bldg ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source:

II ACTUAL OPERATING HOURS: 5057.2 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

Northwest District, 160 Governmental Center, Pensacola, Florida 32501-5794, 904-436-8300
Northeast District, 3426 Bills Rd, Jacksonville, Florida 32207, 904-798-4200
Central District, 3319 Maguire Blvd, Suite 232, Orlando, Florida 32803-3767, 407-894-7555
Southwest District, 4520 Oak Fair Blvd, Tampa, Florida 33610-7347, 813-623-5561
South District, 2269 Bay St, Fort Myers, Florida 33901-2896, 813-332-2667
Southeast District, 1900 S Congress Ave, Suite A, West Palm Beach, Florida 334[illegible], 407-964-9668

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

392,375.0	10^6 cubic feet Natural Gas		10^3 Kerosene
11,269	10^3 gallons 6 Oil, 2 1.5 %S		tons Coal
	10^3 gallons Propane		tons Carbonaceous
	10^6 Black Liquor Solids		tons Refuse

Other (Specify type and units) ____________

VI EMISSION RATE(S) (tons/yr)

	Particulates		Sulfur Dioxide		Total Reduced Sulfur
	Nitrogen Oxide		Carbon Monoxide		Fluoride
	Hydrocarbon	Other (Specify type and units)			

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 6.0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

____
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

____
TYPED NAME AND TITLE

____
DATE

Florida Department of Environmental Regulation

Twin Towers Office Bldg ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

DER Form #

Form Title

Effective Date

DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack second from North end.

II ACTUAL OPERATING HOURS: 2035.9 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

Northwest District 160 Governmental Center Pensacola, Florida 32501-5794 904-436-8300

Northeast District 3426 Bills Rd Jacksonville, Florida 32207 904-798-4200

Central District 3319 Maguire Blvd., Suite 232 Orlando, Florida 32803-3767 407-894-7555

Southwest District 4520 Oak Fair Blvd Tampa, Florida 33610-7347 813-623-5561

South District 2269 Bay St Fort Myers, Florida 33901-2896 813-332-2667

Southeast District 1900 S. Congress Ave., Suite A West Palm Beach, Florida 33406 407-964-9668

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

76,466.7	10^6 cubic feet Natural Gas	________	10^3 Kerosene
123,978.9	10^3 gallons 6 Oil, 2.5 %S	________	tons Coal
________	10^3 gallons Propane	________	tons Carbonaceous
________	10^6 Black Liquor Solids	________	tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute was 1.0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________________________________ TYPED NAME AND TITLE

________________________________ DATE

Florida Department of Environmental Regulation

Twin Towers Office Bldg ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black Steel stack on North end of Plant

II ACTUAL OPERATING HOURS: 4549.9 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

Northwest District, 160 Governmental Center, Pensacola, Florida 32501-5794, 904-436-8300
Northeast District, 3426 Bills Rd, Jacksonville, Florida 32207, 904-798-4200
Central District, 3319 Maguire Blvd, Suite 232, Orlando, Florida 32803-3767, 407-894-7555
Southwest District, 4520 Oak Fair Blvd, Tampa, Florida 33610-7347, 813-623-5561
South District, 2269 Bay St, Fort Myers, Florida 33901-2896, 813-332-2667
Southeast District, 1900 S Congress Ave, Suite, West Palm Beach, Florida, 407-964-9668

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

403.204.6 10⁶ cubic feet Natural Gas ______ 10^3 Kerosene

28.481 10^3 gallons 6 Oil, 1.5 %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 5.2 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1990 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div; Bldg. 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack, south end of plant

II ACTUAL OPERATING HOURS: 809.4 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,00 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

20,523 10^6 cubic feet Natural Gas

N/A 10^3 gallons ________ Oil, ________ %S

________ 10^3 gallons Propane

________ 10^6 Black Liquor Solids

________ 10^3 Kerosene

________ tons Coal

________ tons Carbonaceous

________ tons Refusé

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________ TYPED NAME AND TITLE

________ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 90 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div; Bldg. 473
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 3440.0 hrs/~~day~~XX ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

124.076 10^6 cubic feet Natural Gas

N/A 10^3 gallons ________ Oil, ________ %S

________ 10^3 gallons Propane

________ 10^6 Black Liquor Solids

________ 10^3 Kerosene

________ tons Coal

________ tons Carbonaceous

________ tons Refuse

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

____
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

____
TYPED NAME AND TITLE

____
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1990 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg. 473
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack center of plant

II ACTUAL OPERATING HOURS: 2648.1 hrs/~~day~~ ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,00 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

248.350 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

0.019 10^3 gallons 6 Oil, 1.5 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

I **EMISSION RATE(S)** (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________________

VII **METHOD OF CALCULATING EMISSION RATES** (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 6.0 percent.

VIII **CERTIFICATION:**

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 90 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg. 473
   Gainesville Fl. 32611
4. Description of Source: Black steel stack second from North end of plant

II ACTUAL OPERATING HOURS: 4739.2 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

210.507	10^6 cubic feet Natural Gas	________	10^3 Kerosene
0.870	10^3 gallons 6 Oil, 1.5 %S	________	tons Coal
________	10^3 gallons Propane	________	tons Carbonaceous
________	10^6 Black Liquor Solids	________	tons Refuse

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________	Particulates	________	Sulfur Dioxide	________	Total Reduced Sulfur
________	Nitrogen Oxide	________	Carbon Monoxide	________	Fluoride
________	Hydrocarbon		Other (Specify type and units) ________		

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacticy. The highest six-minute was 1.0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________________________________ TYPED NAME AND TITLE

________________________________ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1990 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical plant Div. Bldg. 473
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack on North end of plant

II ACTUAL OPERATING HOURS: 5115.6 hrs/~~day~~XXX ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs. per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

416.845	10^6 cubic feet Natural Gas	______	10^3 Kerosene
5.557	10^3 gallons 6 Oil, 1.5 %S	______	tons Coal
______	10^3 gallons Propane	______	tons Carbonaceous
______	10^6 Black Liquor Solids	______	tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. the highest six-minute average was 5.2 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE