Florida
Power
CORPORATION

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August 3, 1992

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

Dear Mr. Fancy:

Re: Polk County Site
PSD Permit Application

Enclosed is Florida Power Corporation's (FPC) Prevention of Significant Deterioration (PSD) Permit Application for 940 MW of combined cycle units and an auxiliary boiler at the proposed Polk County Site. Also enclosed is a $7,500 check to cover the application processing fee. The modeling data to support this application in diskette and hard copy form are being sent under separate cover.

This application is being filed concurrently with the Florida Department of Environmental Regulation, the Environmental Protection Agency, and the National Park Service. It will be appended to FPC's Site Certification Application for the Polk County Site to be filed later this month, pursuant to the Florida Electrical Power Plant Siting Act (Chapter 403, Part II, Florida Statutes).

Should you have any questions on this application or any aspect of the proposed project, please call me at (813) 866-5529, or Mr. Scott Osbourn at (813) 866-5158.

Very truly yours,

Kathy Small

Kathleen L. Small
Environmental Project Manager

Enclosures

cc: H. S. Oven (FDER) - w/o enc.
Jewell Harper (EPA) - w/enc.
Chris Shaver (NPS) - w/enc.
S. Arif
C. Holladay
B. Thomas, SW Dist.
L. Novak, Polk Co.

pag\KLS\1992\Fancy.Let

GENERAL OFFICE: 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

Florida Power
CORPORATION

ACCOUNTS PAYABLE DEPT. B3F
P O BOX 14042
ST. PETERSBURG, FL 33733-4042
(813) 866-5257

REMITTANCE ADVICE

89

CHECK DATE 07/30/92 **VENDOR** FLORIDA DEPARTMENT OF **VENDOR NO.** 284216 **CHECK NO.** 1446768

INVOICE NO.	DATE	OUR ORDER NO.	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
FL0727750 CK79987	07/27/92		9207147480	7,500.00	.00	7,500.00
					TOTAL	7,500.00

Sent Original Check
to F&A.
Bob

THE ATTACHED REMITTANCE IS IN FULL SETTLEMENT OF ACCOUNT AS STATED. IF NOT CORRECT PLEASE RETURN TO ABOVE ADDRESS.

Accounts Payable Department B3F
P.O. Box 14042
St. Petersburg, Fl 33733-4042

Florida Power
CORPORATION

63-327
631

DATE 07/30/92 CHECK NO. **1446768**

PAY $7*THOUSAND*500*DOLLARS AND 00 CENTS $*****7,500.00

Void after 60 days

NCNB National Bank of Florida
Tampa, Florida

TO THE ORDER OF
FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
2600 BLAIR STONE RD
TALLAHASSEE FL 32399-2400

K E McDonald

⑈1446768⑈ ⑆063100277⑆ 3601846802⑈

DER FILE COPY

PSD Permit Application
For The

Florida Power Corporation Polk County Site

Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

August 1992

Florida Power
CORPORATION

PSD PERMIT APPLICATION

FOR THE

FLORIDA POWER CORPORATION
POLK COUNTY SITE

August 1992

Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

APPLICATION FORMS

Florida Department of Environmental Regulation

Application to Operate/Construct Air Pollution Sources

940 MW of Combined Cycle Units

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 ____
(Filled in by DER)

AC53-217434
PSD-FL-195

$7,500 pd.
8-4-92
Recpt #180186

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Electric Generating Station [X] New^1 [ ] Existing^1

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

COMPANY NAME: Florida Power Corporation COUNTY: Polk

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) 940 MWs of Combined Cycle units

SOURCE LOCATION: Street 7700 C.R. 555 City Bartow

UTM: East 414.4 km North 3073.9 km

Latitude 27 ° 47 ' 19 "N Longitude 81 ° 52 ' 10 "W

APPLICANT NAME AND TITLE: R.W. Neiser, Sr. Vice President, Legal & Government Affairs

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: R.W. Neiser
R.W. Neiser, Sr. Vice President
Legal & Government Affairs
Name and Title (Please Type)

Date: 8/3/92 Telephone No. (813) 866-5784

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) (1)*

This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

---

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

*Additional information attached.

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 Darrel James Graziani

Darrel James Graziani
Name (Please Type)

Ebasco Environmental
Company Name (Please Type)

759 South Federal Highway
Stuart, Florida 34994
Mailing Address (Please Type)

Florida Registration No. 44685 Date: 7/31/92 Telephone No. (407) 225-8712

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.

For the construction of 940 MW of combined cycle generating units (CC units) fired primarily on natural gas with low sulfur fuel oil as backup. Each CC unit consists of a combustion turbine (CT), a heat recovery steam generator (HRSG) and a steam turbine. An alternate configuration may consist of two 470 MW CC units each consisting of two CTs, two HRSGs and a single steam turbine. Each CT will utilize dry low NOx combustors (12 p[illegible]v @ 15% O_2) when fired on natural gas and water injection (42 ppmvd @ 15% O_2) when fired o[illegible] fuel oil. Each CC unit is rated at 235 MW for an initial site capacity of 940 MW (Phase I) The project will result in full compliance with PSD, NSPS and FDER requirements.

1st CT START-UP 1998

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

Start of Construction April, 1995 Completion of Construction November, 2000

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.)

Capital costs and levelized annual costs for the selected control option (BACT) are attached. PSD Application - Section 4, Tables 4-3 and 4-4.

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

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;
if power plant, hrs/yr 8760; if seasonal, describe:

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? NA

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

   c. If yes, list non-attainment pollutants. NA

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

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

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

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? NA

   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.

NATURAL GAS

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

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

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

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

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

2. Product Weight (lbs/hr): NA

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

One CC Unit – firing Nat Gas

Name of Contaminant	Emission[1] (5)		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr (6)	(7) Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			~~lbs/yr~~ lbs/hr	T/yr	
CO	80	330.40	17-2.500(5)(c) BACT	80	80	350.40	Att. CCU-4
NO_x	76	313.88	17-2.500(5)(c) BACT	76	76	332.88	Att. CCU-4
SO_2	1.03	4.25	17-2.500(5)(c) BACT	1.03	1.03	4.25	Att. CCU-4
PM	9	37.17	17-2.500(5)(c) BACT	9	9	39.42	Att. CCU-4
VOC	11.2	46.256	17-2.500(5)(c) BACT	11.2	11.2	49.06	Att. CCU-4

[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)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

FUEL OIL

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

A. Raw Materials and Chemicals Used in your Process, if applicable: (8)

Description	Contaminants Type	Contaminants % Wt	Utilization Rate - lbs/hr	Relate to Flow Diagram
Water	NA	NA	128600	Attachment CCU-4

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

1. Total Process Input Rate (lbs/hr): 128600

2. Product Weight (lbs/hr): NA

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

One CC Unit

Name of Contaminant	Emission[1] (9) Maximum lbs/hr	Emission[1] (9) Actual T/yr	Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr (6)	(9) Potential[4] Emission ~~lbs/yr~~ lbs/hr	Potential[4] Emission T/yr	Relate to Flow Diagram
CO	96	24	17-2.500(5)(C) BACT	96	96	24	Att. CCU-4
NO_x	318	79.5	17-2.500(5)(C) BACT	318	318	79.5	Att. CCU-4
SO_2	98	24.5	17-2.500(5)(C) BACT	98	98	24.5	Att. CCU-4
PM	17	4.25	17-2.500(5)(C) BACT	17	17	4.25	Att. CCU-4
VOC	12.0	3.00	17-2.500(5)(C) BACT	12.0	12.0	3.00	Att. CCU-4

[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)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

NATURAL GAS

D. Control Devices: (See Section V, Item 4) PSD Application - Section 4

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Dry low NO_x Combusters	Nitrogen Oxides	88%	NA	Att. CCU-3

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	1.58 MMCF/hr @	1.71 MMCF/hr @	1572.5 mm Btu/hr @ 40°F
	72° F	40° F	

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: (10)

Percent Sulfur: 2000 grains/mmSCF Percent Ash: Neg.

Density: .0564 lbs/ft^3 @ 40°F lbs/gal Typical Percent Nitrogen: 0.5%

Heat Capacity: 16,277 (LHV) BTU/lb 918 Btu/ft^3 (LHV) BTU/gal

Other Fuel Contaminants (which may cause air pollution): Benzene and Formadlehyde are associated with natural gas combustion

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

Annual Average NA Maximum NA

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

Both liquid and solid wastes generated at the site will be properly disposed.

FUEL OIL

D. Control Devices: (See Section V, Item 4) PSD Application - Section 4

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Water Injection	Nitrogen Oxide	64%	NA	Att. CCU-3
Low Sulfur Fuel Oil	Sulfur Dioxide	NA	NA	

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Low Sulfur Fuel Oil	12,339 gal/hr	13,505 gal/hr	1799.8 MM Btu/hr @ 40°F
	@ 72°F	@ 40°F	

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: (11)

Percent Sulfur: 0.05 Percent Ash: Trace

Density: 7.1845 lbs/gal Typical Percent Nitrogen: 0.015

Heat Capacity: 18550 (LHV) BTU/lb 133,272.475 (LHV) BTU/gal

Other Fuel Contaminants (which may cause air pollution): Beryllium, Inorganic Arsenic and other trace metals are associated with fuel oil combustion and sulfuric acid mist.

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

Annual Average NA Maximum NA

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

Both liquid and solid wastes generated at the site will be properly disposed.

NATURAL GAS

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

Stack Height: 113 (34.4 m) ft. Stack Diameter: 13.5 (4.10 m) ft.

Gas Flow Rate: 996246.15 ACFM - DSCFM Gas Exit Temperature: 200 (366.3^{o}k) °F.

Water Vapor Content: - % Velocity: 116 (35.3 mps) FPS

SECTION IV: INCINERATOR INFORMATION NA

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
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 Diamter: 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 device: ☐ Cyclone ☐ Wet Scrubber ☐ Afterburner

☐ Other (specify)

FUEL OIL

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

Stack Height: 113 (34.4 m) ft. Stack Diameter: 13.5 (4.1 m) ft.

s Flow Rate: 1,142,248 ACFM ____________ DSCFM Gas Exit Temperature: 260 (400°k) °F.

ter Vapor Content: ____________ % Velocity: 133 (40.5 mps) FPS

SECTION IV: INCINERATOR INFORMATION NA

Type of Waste	Type 0 (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Patholog-ical)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Inciner-ated							
Uncon-trolled (lbs/hr)							

escription of Waste ____________

otal Weight Incinerated (lbs/hr) ____________ Design Capacity (lbs/hr) ____________

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

Manufacturer ____________

ate Constructed ____________ Model No. ____________

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

tack Height: ______ ft. Stack Diamter: ______ 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 device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ____________

c

Brief description of operating characteristics of control devices: NA

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

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)]
   Not Applicable
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. Attachment CCU-1
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   Attachment CCU-2
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.) Not Applicable
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). Attachment CCU-3
6. An 8 1/2" 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. Attachment CCU-4, Figure CCU-1
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).
   PSD Application - Figure 1-1
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   PSD Application - Figure 2-2

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

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. Not Applicable

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?

[X] Yes [ ] No

Contaminant	Rate or Concentration
Nitrogen Oxides	75 ppmvd @ 15% O_2 (not corrected)
Sulfur Dioxide	Fuel Sulfur Content ≤ 0.8% by weight

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy) PSD Application - Section 4.0, Page 4-1

[X] Yes [ ] No

Contaminant	Rate or Concentration
Nitrogen Oxides (Section 4.3)	42 ppmvd @ 15% O_2
Sulfur Dioxide (Section 4.4)	Fuel Sulfur Content ≤ 0.5% by weight

C. What emission levels do you propose as best available control technology?
PSD Application - Section 4.10, Table 4-7

Contaminant	Rate or Concentration
Nitrogen Oxides	12/42 ppmvd @ 15% O_2
Sulfur Dioxide/Sulfuric acid mist /Sulfuric acid mist	Fuel Sulfur Content ≤ 0.05% by weight
Carbon Monoxide	25/30 ppmvd
PM/PM10, VOC, Benzene, Beryllium	Good combustion and limited fuel oil usage

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

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

*Explain method of determining

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). PSD Application - Section 4.0

1.

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:

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 Costs:

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: PSD Application - Section 4.0

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

PSD Application - Section 5

A. Company Monitored Data

1. One (1) no. sites Yes PM-10 Yes (C) SO^2* Yes Wind spd/dir

Period of Monitoring 10 / 15 / 91 (month day year) to 02 / 14 / 92 (month day year)

Other data recorded Ozone

Attach all data or statistical summaries to this application. PSD Application - Section 5

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

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

[X] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling PSD Application - Section 6.3

1. 5 Year(s) of data from 01 / 01 / 82 (month day year) to 12 / 31 / 86 (month day year)

2. Surface data obtained from (location) Tampa/Ruskin - FDER Preprocessed Format

3. Upper air (mixing height) data obtained from (location) Tampa/Ruskin - FDER Preprocessed Format

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

C. Computer Models Used PSD Application - Sections 6 & 8

1. ISCST - Version 90346 Modified? If yes, attach description.

2. VISCREEN Version 1.01 (88341) 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 PSD Application - Section 7

Pollutant	Emission Rate	
TSP	4.56/8.56 Natural Gas/Fuel Oil	grams/sec
SO^2	0.52/49.44	grams/sec

E. Emission Data Used in Modeling PSD Application - Section 6

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. PSD Application - Section 8

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. PSD Application - Section 4.0

ADDITIONAL INFORMATION

Combined Cycle Units

Application to Operate/Construct Air Pollution Sources

1. BACT analysis, GEP stack height analysis and combustion turbine performance parameters were prepared by Black & Veatch. Attachment CCU-5

2. BACT analysis is attached. PSD Application - Section 4.0.

3. PSD Application is attached.

4. NSPS applicability determination is attached. PSD Application - Section 3.4.3.

5. Actual emissions based on a single CC unit fired on natural gas (LHV - 918 Btu/SCF) for 8260 hours per year, manufacturers data and AP-42(SO_2).

6. Requested allowable emission levels based on the application of BACT on a single CC unit and a daily block average (midnight to midnight).

7. Potential emissions based on a single CC unit fired on natural gas (LHV - 918 Btu/SCF) for 8760 hours per year and no conversion to SO_3.

8. Water is used for NO_x controls only when a CC unit is fired on fuel oil.

9. Actual and potential emissions based on a single CC unit fired on fuel oil for no more than 500 hours per year.

10. Natural gas fuel analysis from Florida Gas Transmission data.

11. Fuel oil sulfur content has been negotiated with the fuel supplier. PSD Application - Section 2, Table 2-7, provides a fuel oil analysis.

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 2

Emission Estimate Basis

(Attachment CCU-1)

Emission estimates are for a single CC unit and were obtained from manufacturer's test data provided by General Electric for their dry low NO_x combustion system (DLN III) for the PG-7221 FA gas turbine. Florida Power Corporation has received verbal commitments from other manufacturer's that their future turbines will be capable of meeting the proposed BACT levels. Emission estimates have not been corrected to ISO conditions or for fuel bound nitrogen.

Natural Gas

Nitrogen Oxides(1): 12ppm --- 76.00 lbs/hr

POLLUTANTS

Carbon Monoxide: 25 ppmvd --- 80 lbs/hr

Volatile Organic Compounds(2): (14 lbs/hr) (0.80) = 11.2 lbs/hr

Particulate Matter: 9.0 lbs/hr

Sulfur Dioxide(3): (1572.5 mmBTU/hr)(1/918mmBTU/mmSCF)(.6 lbs/mmSCF) = 1.03 lbs/hr

Sulfuric Acid Mist(3): (1.03 lbs/hr)(mols/64lbs)(7%)(98 lbs/mol) = 0.11 lbs/hr

Benzene(4): (1572.5 mmBTU/hr)(6.80E-5 lbs/mmBTU) = 0.107 lbs/hr

Formaldehyde(4): (1572.5 mmBTU/hr)(2.20E-4 lbs/mmBTU) = 0.346 lbs/hr

Fuel Oil

Nitrogen Oxides: 42 ppmvd --- 318 lbs/hr

Carbon Monoxide: 30 ppmvd --- 96 lbs/hr

Volatile Organic Compounds: (15 lbs/hr)(0.80) = 12 lbs/hr

Particulate Matter: 17 lbs/hr

Sulfur Dioxide(5): 92 lbs/hr + (6 lbs/hr)(mols/80 lbs)(64 lbs/mol) = 98.4 lbs/hr

Sulfuric Acid Mist: 10 lbs/hr

Trace Metals(6): 4.24 lbs/hr

Notes

(1) NO_x emissions have not been corrected to ISO conditions or for fuel bound nitrogen. Fuel bound nitrogen amounts greater than 0.015% will add to the reported NO_x values.

(2) VOC emissions estimated at 80 percent of total unburned hydrocarbons.

(3) SO_2 emissions based on 0.6 lbs/mmscf(AP-42, 1986) for natural gas combustion. H_2SO_4 emissions based on a coversion rate of 7 percent of SO_2 to SO_3 and complete conversion of SO_3 to H_2SO_4. Requested allowable SO_2 emission based on no conversion.

(4) Emission estimates based on natural gas combustion.

(5) SO_2 emissions include SO_3 emissions.

(6) Trace metal emissions based on low sulfur fuel oil combustion

BLACK & VEATCH - FLORIDA POWER
****

ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	40	40	40	40	40
AMBIENT RELATIVE HUMID	- %	70	70	70	70	70
OUTPUT	- kW	165000.	131900.	99400.	66100.	32900.
HEAT RATE (LHV)	- Btu/kWh	9530.	10270.	11630.	13970.	19860.
HEAT CONS. (LHV) X10-6	- Btu/h	1572.5	1354.6	1156.0	923.4	653.4
EXHAUST FLOW X10-3	- lb/h	3500.0	2903.0	2500.0	2123.0	1901.0
EXHAUST TEMP	- Deg F.	1089.	1157.	1200.	1200.	1055.
EXHAUST HEAT X10-6	- Btu/h	955.0	857.3	775.8	663.9	515.0
NOX	- ppmvd @ 15% 02	12.	12.	12.	12.	124.
NOX AS NO2	- lb/h	76.	65.	55.	44.	313.
CO	- ppmvd	25.	25.	25.	*	*
CO	- lb/h	80.	65.	57.	*	*
UHC	- ppmvv	7.	7.	7.	*	*
UHC	- lb/h	14.	11.	10.	*	*
PART	- lb/h	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

ARGON	0.90	0.90	0.89	0.90	0.90
NITROGEN	74.76	74.67	74.72	74.91	75.49
OXYGEN	12.67	12.43	12.57	13.11	14.76
CARBON DIOXIDE	3.78	3.89	3.83	3.58	2.82
WATER	7.89	8.11	7.99	7.50	6.03

SITE CONDITIONS
****

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	70
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20790
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(1).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 6-9-92

BLACK & VEATCH - FLORIDA POWER
****

ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	72	72	72	72	72
AMBIENT RELATIVE HUMID	- %	80	80	80	80	80
OUTPUT	- kW	147400.	118500.	88800.	59200.	29900.
HEAT RATE (LHV)	- Btu/kWh	9850.	10620.	12100.	14590.	20910.
HEAT CONS. (LHV) X10-6	- Btu/h	1451.9	1258.5	1074.5	863.7	625.2
EXHAUST FLOW X10-3	- lb/h	3266.0	2741.0	2405.0	2052.0	1818.0
EXHAUST TEMP	- Deg F.	1117.	1177.	1200.	1200.	1086.
EXHAUST HEAT X10-6	- Btu/h	898.5	810.0	733.0	629.5	497.9
NOX	- ppmvd @ 15% O2	12.	12.	12.	12.	109.
NOX AS NO2	- lb/h	70.	60.	51.	41.	266.
CO	- ppmvd	25.	25.	25.	*	*
CO	- lb/h	73.	62.	53.	*	*
UHC	- ppmvw	7.	7.	7.	*	*
UHC	- lb/h	13.	11.	10.	*	*
PART	- lb/h	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

ARGON	0.89	0.88	0.88	0.89	0.89
NITROGEN	73.63	73.57	73.65	73.82	74.30
OXYGEN	12.49	12.30	12.57	13.07	14.46
CARBON DIOXIDE	3.72	3.81	3.68	3.45	2.81
WATER	9.28	9.45	9.22	8.77	7.54

SITE CONDITIONS
****

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	80
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20790
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(1).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 6-9-92

BLACK & VEATCH - FLORIDA POWER
****

ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	95	95	95	95	95
AMBIENT RELATIVE HUMID	- %	48	48	48	48	48
OUTPUT	- kW	133300.	106400.	80100.	53100.	27200.
HEAT RATE (LHV)	- Btu/kWh	10190.	11080.	12570.	15310.	22100.
HEAT CONS. (LHV) X10-6	- Btu/h	1358.3	1178.9	1006.9	813.0	601.1
EXHAUST FLOW X10-3	- lb/h	3099.0	2630.0	2327.0	1991.0	1762.0
EXHAUST TEMP	- Deg F.	1137.	1191.	1200.	1200.	1107.
EXHAUST HEAT X10-6	- Btu/h	856.1	774.2	697.1	601.1	483.7
NOX	- ppmvd @ 15% O2	12.	12.	12.	12.	107.
NOX AS NO2	- lb/h	65.	51.	48.	38.	248.
CO	- ppmvd	25.	25.	25.	*	*
CO	- lb/h	70.	58.	52.	*	*
UHC	- ppmvw	7.	7.	7.	*	*
UHC	- lb/h	12.	10.	9.	*	*
PART	- lb/h	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

ARGON	0.88	0.87	0.88	0.89	0.88
NITROGEN	73.26	73.22	73.32	73.48	73.90
OXYGEN	12.50	12.39	12.72	13.20	14.40
CARBON DIOXIDE	3.66	3.72	3.56	3.34	2.79
WATER	9.70	9.80	9.53	9.10	8.03

SITE CONDITIONS
****

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	48
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20790
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS. NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i). NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 6-9-92

BLACK & VEATCH - FLORIDA POWER
****

ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	40	40	40	40	40
AMBIENT RELATIVE HUMID	- %	70	70	70	70	70
OUTPUT	- kW	178200.	143200.	106900.	70500.	35800.
HEAT RATE (LHV)	- Btu/kWh	10100.	10860.	12270.	14580.	18880.
HEAT CONS. (LHV) X10-6	- Btu/h	1799.8	1555.2	1311.7	1027.9	675.9
EXHAUST FLOW X10-3	- lb/h	3652.0	3028.0	2551.0	2152.0	2027.0
EXHAUST TEMP	- Deg F.	1071.	1142.	1200.	1200.	1027.
EXHAUST HEAT X10-6	- Btu/h	997.5	900.1	809.4	684.5	527.0
WATER FLOW	- lb/h	129530.	109860.	88920.	63480.	0.
NOX	- ppmvd @ 15% O2	42.	42.	42.	42.	240.
NOX AS NO2	- lb/h	318.	273.	228.	177.	660.
CO	- ppmvd	30.	30.	50.	80.	*
CO	- lb/h	96.	79.	112.	152.	*
UHC	- ppmvw	7.	10.	20.	40.	*
UHC	- lb/h	15.	17.	29.	51.	*
SO2	- ppmvw	11.	12.	12.	11.	8.
SO2	- lb/h	92.	80.	67.	53.	35.
SO3	- ppmvw	1.	1.	1.	1.	0.
SO3	- lb/h	6.	5.	5.	3.	2.
SULFUR MIST	- lb/h	10.	8.	7.	6.	4.
PART	- lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

	BASE	80%	60%	40%	20%
ARGON	0.87	0.86	0.86	0.87	0.92
NITROGEN	71.09	70.92	71.10	71.91	76.13
OXYGEN	10.93	10.61	10.72	11.56	14.96
CARBON DIOXIDE	5.31	5.49	5.45	5.04	3.57
WATER	11.81	12.13	11.88	10.62	4.42

SITE CONDITIONS
****

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	70
FUEL TYPE	-	DISTILLATE
FUEL LHV	- Btu/lb	18550
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS. NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i). NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

DISTILLATE FUEL IS ASSUMED TO HAVE .015% FUEL BOUND NITROGEN, OR LESS. FBN AMOUNTS GREATER THAN .015% WILL ADD TO THE REPORTED NOx VALUE. SULFUR EMISSIONS BASED ON .05 WT% SULFUR CONTENT IN THE FUEL.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 7-22-92

BLACK & VEATCH - FLORIDA POWER
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ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	72	72	72	72	72
AMBIENT RELATIVE HUMID	- %	80	80	80	80	80
OUTPUT	- kW	159200.	128000.	95200.	63300.	32200.
HEAT RATE (LHV)	- Btu/kWh	10330.	11060.	12610.	15070.	20160.
HEAT CONS. (LHV) X10-6	- Btu/h	1644.5	1415.7	1200.5	953.9	649.2
EXHAUST FLOW X10-3	- lb/h	3392.0	2815.0	2451.0	2084.0	1822.0
EXHAUST TEMP	- Deg F.	1102.	1168.	1200.	1200.	1121.
EXHAUST HEAT X10-6	- Btu/h	934.1	837.9	759.1	648.9	513.3
WATER FLOW	- lb/h	106700.	88710.	71140.	51630.	0.
NOX	- ppmvd @ 15% O2	42.	42.	42.	42.	212.
NOX AS NO2	- lb/h	290.	248.	209.	164.	559.
CO	- ppmvd	30.	30.	50.	80.	*
CO	- lb/h	89.	73.	107.	147.	*
UHC	- ppmvw	7.	10.	20.	40.	*
UHC	- lb/h	14.	16.	29.	46.	*
SO2	- ppmvw	11.	12.	11.	11.	8.
SO2	- lb/h	84.	73.	61.	49.	33.
SO3	- ppmvw	1.	0.	1.	0.	1.
SO3	- lb/h	6.	4.	5.	3.	2.
SULFUR MIST	- lb/h	9.	8.	6.	5.	3.
PART	- lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

	BASE	80%	60%	40%	20%
ARGON	0.85	0.85	0.86	0.86	0.89
NITROGEN	70.51	70.44	70.79	71.44	74.84
OXYGEN	10.94	10.68	11.04	11.78	14.29
CARBON DIOXIDE	5.20	5.36	5.18	4.82	3.79
WATER	12.50	12.67	12.13	11.10	6.19

SITE CONDITIONS
****

ELEVATION - ft. 163
SITE PRESSURE - psia 14.62
INLET LOSS - in. Water 3.5
EXHAUST LOSS - in. Water 12
RELATIVE HUMIDITY - % 80
FUEL TYPE - DISTILLATE
FUEL LHV - Btu/lb 18550
APPLICATION - 317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM - DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS. NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i). NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

DISTILLATE FUEL IS ASSUMED TO HAVE .015% FUEL BOUND NITROGEN, OR LESS. FBN AMOUNTS GREATER THAN .015% WILL ADD TO THE REPORTED NOx VALUE. SULFUR EMISSIONS BASED ON .05 WT% SULFUR CONTENT IN THE FUEL.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 7-22-92

BLACK & VEATCH - FLORIDA POWER
****

ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	95	95	95	95	95
AMBIENT RELATIVE HUMID	- %	48	48	48	48	48
OUTPUT	- kW	144200.	115600.	86000.	57100.	29400.
HEAT RATE (LHV)	- Btu/kWh	10630.	11450.	13040.	15670.	21230.
HEAT CONS. (LHV) X10-6	- Btu/h	1532.8	1323.6	1121.4	894.8	624.2
EXHAUST FLOW X10-3	- lb/h	3212.0	2699.0	2376.0	2027.0	1766.0
EXHAUST TEMP	- Deg F.	1124.	1183.	1200.	1200.	1142.
EXHAUST HEAT X10-6	- Btu/h	887.8	800.2	721.8	618.1	498.6
WATER FLOW	- lb/h	95660.	79160.	63000.	46030.	0.
NOX	- ppmvd @ 15% O2	42.	42.	42.	42.	203.
NOX AS NO2	- lb/h	271.	232.	195.	155.	515.
CO	- ppmvd	30.	30.	50.	80.	*
CO	- lb/h	84.	70.	103.	142.	*
UHC	- ppmvw	7.	10.	20.	40.	*
UHC	- lb/h	13.	16.	26.	46.	*
SO2	- ppmvw	11.	11.	11.	10.	8.
SO2	- lb/h	79.	68.	57.	46.	32.
SO3	- ppmvw	1.	1.	0.	1.	1.
SO3	- lb/h	5.	4.	4.	3.	2.
SULFUR MIST	- lb/h	8.	7.	6.	5.	3.
PART	- lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

	BASE	80%	60%	40%	20%
ARGON	0.84	0.85	0.84	0.86	0.90
NITROGEN	70.35	70.36	70.76	71.35	74.42
OXYGEN	11.03	10.87	11.33	12.01	14.23
CARBON DIOXIDE	5.12	5.22	5.00	4.65	3.75
WATER	12.66	12.70	12.07	11.13	6.70

SITE CONDITIONS
****

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	48
FUEL TYPE	-	DISTILLATE
FUEL LHV	- Btu/lb	18550
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS. NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i). NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

DISTILLATE FUEL IS ASSUMED TO HAVE .015% FUEL BOUND NITROGEN, OR LESS. FBN AMOUNTS GREATER THAN .015% WILL ADD TO THE REPORTED NOx VALUE. SULFUR EMISSIONS BASED ON .05 WT% SULFUR CONTENT IN THE FUEL.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 7-22-92

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	
	$kg/10^6m^3$	$lb/10^6\ ft^3$	$kg/10^6m^3$	$lb/10^6\ ft^3$	$kg/10^6m^3$	$lb/10^6\ ft^3$	$kg/10^6m^3$	$lb/10^6\ ft^3$	$kg/10^6m^3$	$lb/10^6\ ft^3$	$kg/10^6m^3$	$lb/10^6\ ft^3$
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.

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 3

Potential Discharge Basis

(Attachment CCU-2)

Potential emissions are based on the current definition contained in Rule 17-2.100(168), F.A.C. and the use of natural gas and low sulfur fuel oil. Emission estimates obtained as described in Attachment CCU-1.

Natural Gas - potential emissions based on operating 8760 hrs/yr on natural gas.

Fuel Oil - potential emissions based on operating a maximum of 500 hrs/yr on fuel oil.

The total worst case emissions are for natural gas at 8260 hrs/yr and fuel oil at 500 hrs/yr for four CC units, except for benzene and formaldehyde.

Carbon Monoxide - [4][(80)(8260) + (96)(500)][1/2000] = 1417.60 TPY

Nitogen Oxides - [4][(76)(8260) + (318)(500)][1/2000] = 1573.52 TPY

Sulfur Dioxide - [4][(0.956)(8260) + (98.4)(500)][1/2000] = 114.19 TPY

Particulate Matter - [4][(9)(8260) + (17)(500)][1/2000] = 165.68 TPY

Volatile Organic Compounds - [4][(11.2)(8260) + (12)(500)][1/2000] = 197.02 TPY

Benzene - [4][0.107][8760][1/2000] = 1.87 TPY

Formaldehyde - [4][0.50][8760][1/2000] = 8.76 TPY

Trace Metals - [4][4.24][1/2000][500] = 5.24 TPY

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 5

Control Efficiency Derivation

(Attachment CCU-3)

FPC has proposed use of dry low NO_x combustors and low sulfur fuel oil as BACT. Based on the information outlined in the PSD Application, Section 4, Table 4-2, estimated NO_x reduction rates for natural gas and low sulfur fuel oil are 88% and 64%, respectively. The sulfur dioxide reduction rate based on use of the low sulfur fuel oil is approximately 90%.

Nitrogen Oxides

Natural Gas: [25ppmvd]/[1 - 0.76] = 104.7ppmvd (Uncontrolled)
Reduction Rate = [1 - 12/104.7][100] = 88.48%

Fuel Oil: 64% as reported

Sulfur Dioxide

Natural Gas: N/A

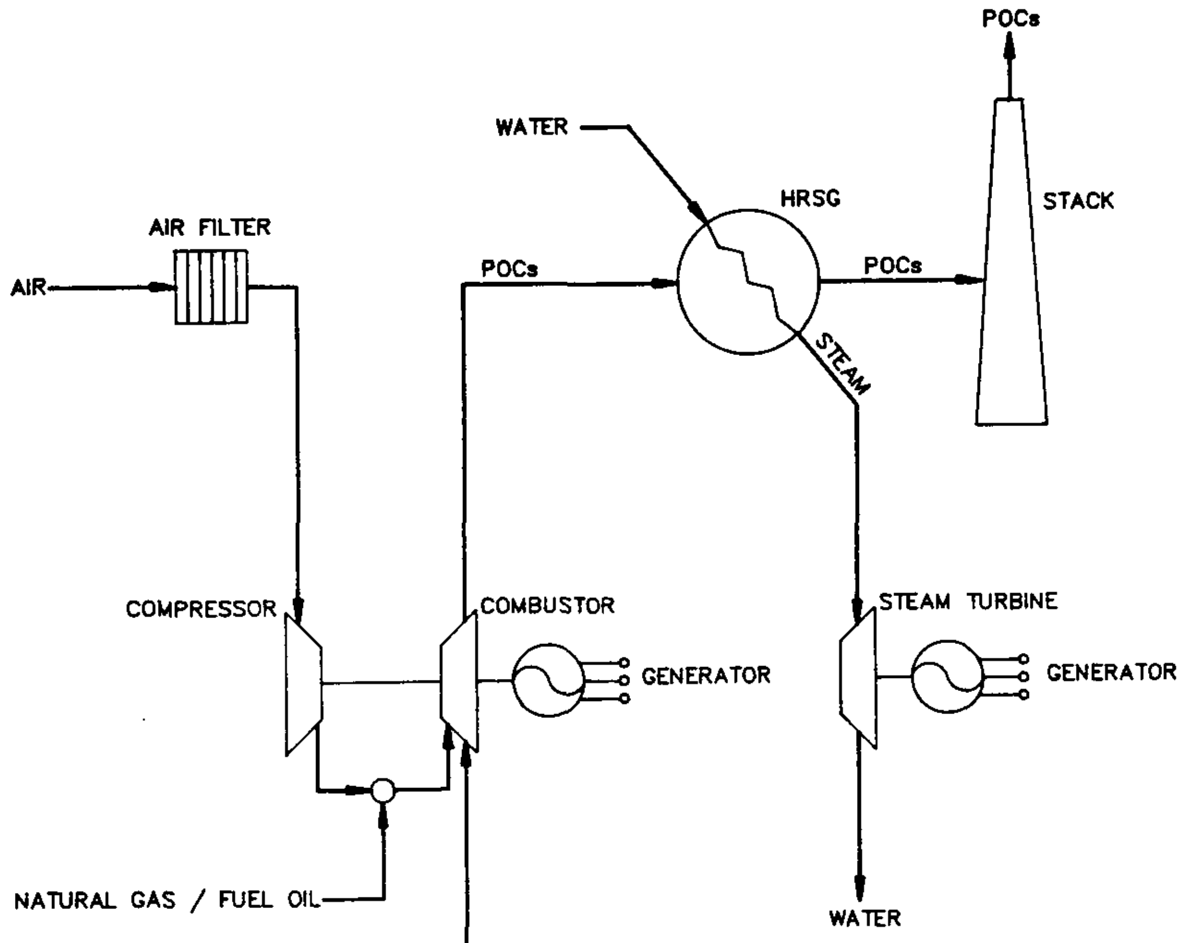
Fuel Oil: Reduction Rate = [1 - 0.05/0.50][100] = 90%

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 6

Flow Diagram

(Attachment CCU-4)



LEGEND

POCs	PRODUCTS OF COMBUSTION
HRSG	HEAT RECOVERY STEAM GENERATOR
*	WATER INJECTION ONLY DURING FUEL OIL FIRING

SOURCE: EBASCO ENVIRONMENTAL, 1992

NOT TO SCALE

Florida Power CORPORATION

Polk County Site

FIGURE 1
SIMPLIFIED FLOW CHART
235 MW COMBINED CYCLE UNIT

ADDITIONAL CERTIFICATIONS

(Attachment CCU-5)

ADDITIONAL CERTIFICATION

This is to certify that the engineering features of the BACT analysis, the GEP stack height analysis, and combustion turbine performance parameters of this FPC Polk County site 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 the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with the PSD air permit application.

Signed Charles J Schutty

Charles J. Schutty
Name (Please Type)

Black & Veatch Engineers
Company Name (Please Type)

11401 Lamar, Overland Park, KS 66211
Mailing Address (Please Type)

Florida Registration No. 43646 Date: 7/30/92 Telephone No. (913) 339-2369

Florida Department of Environmental Regulation

Application to Operate/Construct Air Pollution Sources

One 99 mmBtu/hr Auxiliary Boiler

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. ________

(Filled in by DER)

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Electric Generating Station [X] New[1] [ ] Existing[1]

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

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

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) 99 mmBtu/hr Auxiliary Boiler

SOURCE LOCATION: Street 7700 C.R. 55 City Bartow

UTM: East 414.36 km North 3073.92 km

Latitude 27 ° 47 ' 20 "N Longitude 81 ° 52 ' 9 "W

APPLICANT NAME AND TITLE: R.W. Neiser, Sr. Vice President, Legal & Governmental Affairs

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: R.W. Neiser

R.W. Neiser, Senior Vice President
Legal and Governmental Affairs
Name and Title (Please Type)

Date: 8/3/92 Telephone No. 813/866-5784

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) (1)*

This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

---

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

*Additional information attached.

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 Darrel James Graziani

Darrel James Graziani
Name (Please Type)

Ebasco Environmental
Company Name (Please Type)

759 South Federal Highway
Stuart, FL 34994
Mailing Address (Please Type)

Florida Registration No. 44685 Date: 7/31/92 Telephone No. (407) 225-8712

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.

For the construction of a 99 mmBtu/hr auxiliary boiler fired on either natural gas or low sulfur fuel oil for no more than 100 hours per year. The boiler will utilize low NOx burners and fuel oil with a sulfur content of less than 0.05 percent by weight. The project will result in full compliance with the PSD, NSPS, and FDER requirements.

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

Start of Construction April, 1995 Completion of Construction November, 1998

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.)

Not applicable - Low sulfur fuel oil will be available on site.

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

Requested permitted equipment operating time: hrs/day NA ; days/wk NA ; wks/yr NA ;
if power plant, hrs/yr 100 ; if seasonal, describe: Auxiliary boiler is to be used only during a cold start-up of the combined cycle units.

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? NA
   b. If yes, has "Lowest Achievable Emission Rate" been applied? NA
   c. If yes, list non-attainment pollutants. -

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

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

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

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.

NATURAL GAS

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

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

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

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

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

2. Product Weight (lbs/hr): NA

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1] (5)		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr (6)	(5) Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			XXXXXX lbs/hr	T/yr	
CO	4.95	0.25	17-2.500(5)(C) BACT	4.95	4.95	0.25	Attach AB-4
NOx	9.90	0.50	17-2.500(5)(C) BACT	9.90	9.90	0.50	Attach AB-4
SO_2	0.0641	0.0032	17-2.600(6) BACT	0.0641	0.0641	0.0032	Attach AB-4
PM	0.50	0.02	17-2.600(6) BACT	0.50	0.50	0.02	Attach AB-4
VOC	0.50	0.02	17-2.500(5)(C) BACT	0.50	0.50	0.02	Attach AB-4

[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)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

FUEL OIL

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

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

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

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

1. Total Process Input Rate (lbs/hr): NA
2. Product Weight (lbs/hr): NA

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1] (7)		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr (8)	(7) Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
CO	4.9	0.25	17-2.500(5)(C) BACT	4.9	4.9	0.25	Attach AB-4
NOx	19.80	0.99	17-2.500(5)(C) BACT	19.80	19.80	0.99	Attach AB-4
SO_2	5.27	0.26	17-2.500(6) BACT	5.27	5.27	0.26	Attach AB-4
PM	4.9	0.25	17-2.600(6) BACT	4.90	4.90	0.25	Attach AB-4
VOC	0.99	0.05	17-2.500(5)(C) BACT	0.99	0.99	0.05	Attach AB-4

[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)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

NATURAL GAS

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Low NOx Burner	NOx	25%	NA	Att. AB-3

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	-	0.108 mmSCF/hr	99

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: (9)

Percent Sulfur: Trace (2000 gr/mmSCF) Percent Ash: Neg.

Density: 0.0564 lbs/ft^3 @ 40^{o}F ~~lbs/gal~~ Typical Percent Nitrogen: 0.5%

Heat Capacity: 16,277 (LHV) BTU/lb 918 Btu/ft^3 (LHV)

Other Fuel Contaminants (which may cause air pollution): Benzene and formaldehyde are associated with natural gas combustion.

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

Annual Average NA Maximum NA

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

Both liquid and solid wastes generated at the site will be properly disposed.

FUEL OIL

D. **Control Devices:** (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Low NOx Burner	NOx	NA	NA	Att. AB-4
Low Sulfur Fuel Oil	SO_2	90%	NA	Att. AB-4

E. **Fuels**

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Low Sulfur Fuel Oil	-	742.8 gal/hr	99 mmBtu/hr

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: (10)

Percent Sulfur: 0.05 Percent Ash: Trace

Density: 7.1845 lbs/gal Typical Percent Nitrogen: 0.015

Heat Capacity: 18550 (LHV) BTU/lb 133272.473 (LHV) BTU/gal

Other Fuel Contaminants (which may cause air pollution): Beryllium, Inorganic Arsenic and other trace metals associated with fuel oil combustion.

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

Annual Average NA Maximum NA

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

Both liquid and solid wastes generated at the site will be properly disposed.

NATURAL GAS

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

Stack Height: 60 (28.3m) ft. Stack Diameter: 2.5 (0.76m) ft.

Gas Flow Rate: 32103.150 ACFM - DSCFM Gas Exit Temperature: 332 (437.9 K) °F.

Water Vapor Content: - % Velocity: 109 (33.3mps) FPS

SECTION IV: INCINERATOR INFORMATION NA

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
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 Diamter: __________ 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 device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) __________

FUEL OIL

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

St k Height: 60 (18.3m) ft. Stack Diameter: 2.5 (0.76m) ft.

Ga Flow Rate: 31219.577 ACFM - DSCFM Gas Exit Temperature: 329 (438.0 K) °F.

Wa r Vapor Content: - % Velocity: 106 (32.3mps) FPS

SECTION IV: INCINERATOR INFORMATION NA

ype of aste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
ctual b/hr Inciner- ated							
Uncon- rolled bs/hr)							

D scription of Waste

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

proximate Number of Hours of Operation per day day/wk wks/yr.

Manufacturer

te Constructed Model No.

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

tack Height: ft. Stack Diamter: Stack Temp.

as 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.

ype of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify)

Brief description of operating characteristics of control devices: NA

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

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)]
   Not Applicable
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. Attachment AB-1
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   Attachment AB-2
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.) Not Applicable
5. With construction permit application, attach derivation of work practice(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). Attachment AB-3
6. An 8 1/2" 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. Attachment AB-4
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).
   PSD Application - Figure 1-1
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   PSD Application - Figure 2-2

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

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?

[X] Yes [ ] No

Contaminant	Rate or Concentration
Sulfur Dioxide	Fuel Oil Sulfur Content ≤ 0.5% by weight
Particulate Matter	20% Opacity

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

[X] Yes [ ] No

Contaminant	Rate or Concentration
Sulfur Dioxide	Fuel Oil Sulfur Content ≤ 0.3% by weight
Particulate Matter	Fuel Oil Sulfur Content ≤ 0.3% by weight

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

Contaminant	Rate or Concentration
Sulfur Dioxide/Particulate Matter	Fuel Oil Sulfur Content ≤ 0.05% by weight
Nitrogen Oxides	Low NOx Burners
Carbon Monoxide, Volatile Organic Compounds Beryllium & Inorganic Arsenic	Good combustion practices and limited fuel oil usage

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

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

*Explain method of determining

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). PSD Application - Section 6.11

1.

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:

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 Costs:

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: PSD Application - Section 6.1

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

1. One (1) no. sites Yes PM-10 Yes (C) SO2* Yes Wind spd/dir

Period of Monitoring 10 / 15 / 91 to 02 / 14 / 92
month day year month day year

Other data recorded Ozone

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? [X] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[X] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling PSD Application - Section 6.3

1. 5 Year(s) of data from 01 / 01 / 82 to 12 / 31 /86 (month day year to month day year)

2. Surface data obtained from (location) Tampa/Ruskin - FDER Preprocessed Format

3. Upper air (mixing height) data obtained from (location) Tampa/Ruskin

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

C. Computer Models Used

1. ISCST - Version 90346 Modified? If yes, attach description.

2. VISCREEN Version 1.01 (88341) 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

Pollutant	Emission Rate	
TSP	0.063/0.62 Natural Gas/Fuel Oil	grams/sec
SO^2	0.0081/0.66 Natural Gas/Fuel Oil	grams/sec

E. Emission Data Used in Modeling PSC Application - Section 6

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. PSD Application - Section 8

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. PSD Application - Section 4.0

ADDITIONAL INFORMATION

Auxiliary Boiler

Application to Operate/Construct Air Pollution Sources

1. BACT Analysis, and auxiliary boiler performance parameters prepared by Black & Veatch. Attachment AB-5

2. BACT analysis is attached. PSD Application - Section 4.12

3. PSD Application is attached.

4. NSPS applicability determination is attached. PSD Application - Section 3.4.3

5. Actual and potential emissions based on firing natural gas (LHV - 918 Btu/mm SCF) for 100 hours per year, manufacturer's data and AP-42(SO_2).

6. Requested allowable emission levels when fired on natural gas based on the application of BACT and a daily block average (midnight to midnight).

7. Actual and potential emissions levels based on low sulfur fuel oil for no more than 100 hours per year, manufacturer's data and AP-42(SO_2).

8. Requested allowable emission levels when fired on low sulfur fuel oil after the application of BACT and a daily block average (midnight to midnight).

9. Natural gas fuel analysis from Florida Gas Transmission data.

10. Fuel oil sulfur content has been negotiated with the fuel supplier. PSD Application - Section 2, Table 2-7, provides a fuel oil analysis.

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 2

Emission Estimate Basis

(Attachment AB-1)

Emission estimates were obtained from manufacturer's data and AP-42(SO_2) for boilers with a heat input rate between 79 and 185 mmBtu/hr.

Natural Gas

Nitrogen Oxides: (0.10 lbs/mmBtu)(99 mmBtu/hr) = 9.90 lbs/hr

Carbon Monoxide: (0.05 lbs/mmBtu)(99 mmBtu/hr) = 4.95 lbs/hr

Volatile Organic Compounds(1): (0.005 lbs/mmBtu)(99 mmBtu/hr) = 0.50 lbs/hr

Particulate Matter: (0.005 lbs/mmBtu)(99 mmBtu/hr) = 0.50 lbs/hr

Sulfur Dioxide(2): (0.6lbs/mmSCF)(99 mmBtu/hr)(1/918mmBtu/mmSCF) = 0.0647 lbs/hr
(0.0647 lbs/hr)(mols/64lbs)(99%)(64lbs/mol) = 0.0641 lbs/hr

Sulfuric Acid Mist(2): (0.064 lbs/hr)(mols/64lbs)(1%)(98 lbs/mol) = 0.00099 lbs/hr

Benzene(3): (6.8E-5 lbs/mmBtu) (99 mmBtu/hr) = 0.0067 lbs/hr

Formaldehyde(3): (2.2E-4 lbs/mmBtu((99 mmBtu/hr) = 0.022 lbs/hr

Fuel Oil

Nitrogen Oxides: (0.20 lbs/mmBtu)(99 mmBtu/hr) = 19.80 lbs/hr

Carbon Monoxide: (0.05 lbs/mmBtu)(99 mmBtu/hr) = 4.9 lbs/hr

Volatile Organic Compounds: (0.01 lbs/mmBtu)(97 mmBtu/hr) = 0.99 lbs.hr

Particulate Matter: (0.05 lbs/mmBtu)(99 mmBtu/hr) = 4.9 lbs/hr

Sulfur Dioxide(4): (742.8 gal/hr)(7.1845 lbs/gal)(0.05%S)(mols/32)(64lbs/mol)(99%) =
5.27 lbs/hr

Sulfuric Acid Mist(4):(742.8 gal/hr)(7.1845 lbs/gal)(0.05%S)(mol/32lbs)(1%)(98lbs/mol) =
0.082 lbs/hr

Trace Metals(5): 0.26 lbs/hr

Notes

(1) VOC emission estimate obtained from manufacturer's data sheet.

(2) SO_2 emission estimate based on 0.6 lbs/mmSCF(AP-42, 1986) for natural gas and 1 percent conversion to H_2SO_4.

(3) Emission estimates based on natural gas combustion.

(4) SO_2 emission estimate based on fuel oil sulfur content and 99 percent conversion to SO_2 and 1 percent conversion to H_2SO_4.

(5) Trace metals emissions based on low sulfur fuel oil combustion.

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.

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		Methane	
	kg/10^3l	lb/10^3gal	kg/10^3l	lb/10^3gal	kg/10^3l	lb/10^3gal	kg/10^3l	lb/10^3gal	kg/10^3l	lb/10^3gal	kg/10^3l	lb/10^3gal	kg/10^3l	lb/10^3gal
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: $>106 \times 10^9$ J/hr ($>100 \times 10^6$ Btu/hr)
Industrial boilers: 10.6×10^9 to 106×10^9 J/hr (10×10^6 to 100×10^6 Btu/hr)
Commercial boilers: 0.5×10^9 to 10.6×10^9 J/hr (0.5×10^6 to 10×10^6 Btu/hr)
Residential furnaces: $<0.5 \times 10^9$ J/hr ($<0.5 \times 10^6$ 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.

[illegible]

Per my conversation with Tim Locke, I have the following emissions for natural gas or #2 oil (with .015 percent fuel bound nitrogen by weight).

Tim Locke

4/10/92

EMISSIONS FOR TURNDOWN

8:1 ON NG

6:1 ON OIL

8—10:1 ON NG

CO-200 PPM

6-8:1 ON OIL

CO-200 PPM

→Bayonne Location
Heat Input = 79.027/75.381 MMBTU/HR
Nebraska Boiler # = N2S-6-64-ECON-SH

Natural gas	Lbs/MMBTU	Lbs/MMBTU
NOx	0.10	0.20
CO	0.05	0.05
NMHC	0.005	0.01
Particulates	0.005	0.05
Excess air	20%	20%
FGR %	4	0
FGR Flow (Lbs/HR)	2,833	0
Burner Size	DAF26	DAF26
Burner Delta P	6.4" WC	5.93" WC

Ridgefield Location
Heat Input = 154.34/147.198 MMBTU/HR
Nebraska Boiler # = N2S-7-96-ECON-SH

Natural gas	Lbs/MMBTU	Lbs/MMBTU
NOx	0.10	0.20
CO	0.05	0.05
NMHC	0.005	0.01
Particulates	0.005	0.05
Excess air	20%	20%
FGR %	6	4
FGR Flow (Lbs/HR)	6,299	5,603
Burner Size	DAF36	DAF36
Burner Delta P	6.93" WC	6.74" WC

Clark Location
Heat Input = 165.686/177.136 MMBTU/HR
Nebraska Boiler # = N2S-7-106-ECON-SH

Natural gas	Lbs/MMBTU	Lbs/MMBTU
NOx	0.10	0.20
CO	0.05	0.05
NMHC	0.005	0.01
Particulates	0.005	0.05
Excess air	20%	20%
FGR %	6	5
FGR Flow (Lbs/HR)	13,313	8,428
Burner Size	DAF39	DAF39
Burner Delta P	7.59" WC	7.22" WC

Notes: Emission Guarantees are based on the heat input and analysis given (Black & Veatch 3/27/92 fax to Tomkins & Kinner).

Particulates on oil includes 0.01 percent Ash by weight, 0.05 percent sulfur by weight (3% conversion per EPA test method 5 and a filter box temperature of 325 deg F) and assumed conradson carbon of 4%.

```
                         NEBRASKA BOILER COMPANY
                       BOILER PERFORMANCE SUMMARY
=============================================================================
NBC FILE NAME          : WESTINGHOUSE / BAYONNE
PROPOSAL/JOB NUMBER    : PRELIMINARY                      PAGE : 1 OF 1
ENGINEER               : MDK                              DATE : 04-14-1992
BOILER NUMBER          : N2S-6-54-ECON-SH             CAPACITY : 63000 PPH
FUEL FOR SIZING        : #2 OIL
BOILER DESIGN          : 300 PSIG
=============================================================================
FUELS REVIEWED                          NATURAL GAS     #2 OIL
=============================================================================
STEAM FLOW                 (PPH)  :   63,000.00    :   63,000.00
OPERATING STEAM          (PSIG)   :      215.00    :      215.00
SATURATED   STEAM TEMP     (F)    :      394.00    :      394.00
SUPERHEATED STEAM TEMP     (F)    :      441.00    :      440.00
COMBUSTION    AIR TEMP     (F)    :       80.00    :       80.00
ECON WATER SUPPLY TEMP     (F)    :      227.00    :      227.00
ECON WATER    EXIT TEMP    (F)    :      293.00    :      292.00
ECON WATER FLOW           (PPH)   :   64,890.00    :   64,890.00
BOILER WATER FLOW         (PPH)   :   64,890.00    :   64,890.00
BOILER GAS    EXIT TEMP    (F)    :      545.00    :      550.00
ECON    GAS   EXIT TEMP    (F)    :      332.00    :      329.00
COMBUSTION AIR FLW (LBS/HR)       :   69,835.65    :   67,474.88
COMBUSTION GAS FLW (LBS/HR)       :   73,479.23    :   71,365.45
EXCESS AIR                 (%)    :       20.00    :       20.00
HEAT RELEASE  (BTU/HR-CUFT)       :   61,522.74    :   58,641.53
HEAT RELEASE    (BTU/HR-FT2)      :  127,609.00    :  121,632.90
HEAT ABSORBED  (BTU/HR-FT2)       :   44,716.16    :   50,854.45
FURNACE GAS EXIT TEMP      (F)    :    2,070.00    :    2,056.00
SUPERHEATER LMTD           (F)    :    1,610.41    :    1,593.58
SUPERHEATER GAS EXIT       (F)    :    1,985.00    :    1,967.00
=============================================================================
HHV OF FUEL           (BTU/LB)    :   21,800.00    :   19,460.00 <
HHV OF FUEL           (BTU/  )    :    1,000.00    :  139,300.00 <
LHV OF FUEL           (BTU/LB)    :        0.00    :        0.00
LHV OF FUEL           (BTU/  )    :        0.00    :        0.00
FUEL FLOW             (LBS/HR)    :    3,643.59    :    3,890.56
FUEL FLOW             (   /HR)    :   79,430.23    :      543.51
KBH FUEL INPUT       (KBTU/HR)    :   79,430.23    :   75,710.38
BOILER GAS PRESS DROP (IN.)       :        1.27    :        1.11
ECON    GAS PRESS DROP (IN.)      :        0.67    :        0.62
OPTION #1                (IN.)    :        0.00    :        0.00
OPTION #2                (IN.)    :        0.00    :        0.00
OPTION #3                (IN.)    :        0.00    :        0.00
OPTION #4                (IN.)    :        0.00    :        0.00
TOTAL  GAS PRESS DROP (IN.)       :        1.95    :        1.73
FLUE GAS RECIRCULATION   (%)      :        4.00    :        0.00
=============================================================================
HEAT LOSS DRY GAS    (% ASF)      :        4.98    :        5.24
HEAT LOSS FUEL  H2O  (% ASF)      :        0.00    :        0.00
HEAT LOSS COMB. H2O  (% ASF)      :       10.88    :        6.57
HEAT LOSS REFUSE     (% ASF)      :        0.00    :        0.00
HEAT LOSS AIR   H2O  (% ASF)      :        0.13    :        0.13
HEAT LOSS RADIATION  (% ASF)      :        0.58    :        0.58
UNMEASURED LOSSES    (% ASF)      :        1.00    :        1.00
HEAT LOSS TOTAL      (% ASF)      :       17.57    :       13.52
HEAT LOSS EFFICIENCY    (%)       :       82.43    :       86.48
=============================================================================
                   Nebraska Boiler Company - Lincoln
```

```
                        ECONOMIZER SIZING RESULTS
==========================================================================
               (CONFIGURATION IS INLINE AND COUNTERFLOW)
==========================================================================
NBC FILE NAME          : WESTINGHOUSE / BAYONNE
PROPOSAL/JOB NUMBER    : PRELIMINARY
FUEL USED              : #2 OIL
ENGINEER               : MDK                    DATE      :  04-14-1992
BOILER NUMBER          : N2S-6-34-ECON-SH       CAPACITY  :  63000 PPH
==========================================================================
ECONOMIZER GAS INLET  TEMPERATURE                 :      550.0000  DEG F
ECONOMIZER GAS OUTLET TEMPERATURE                 :      330.0000  DEG F
ECONOMIZER GAS FLOW   (THROUGH)                   :   71,381.9500  LBS/HR
ECONOMIZER WATER INLET  TEMPERATURE               :      227.0000  DEG F
ECONOMIZER WATER OUTLET TEMPERATURE               :      292.0000  DEG F
ECONOMIZER WATER FLOW   (THROUGH)                 :   64,890.0000  LBS/HR
==========================================================================
TUBE (OD)                         :         2.0000  INCHES
TUBE WALL THICKNESS               :         0.1050  INCHES
FIN HEIGHT                        :         0.7500  INCHES
FIN THICKNESS                     :         0.0500  INCHES
NUMBER OF FINS PER INCH           :         3.0000
==========================================================================
DUTY                              :     4,302.6160  KBTU/HR
HEATING SURFACE                   :     3,776.4010  FT2
REQUIRED AREA                     :       100.4509  %
DRAFT LOSS                        :         0.6191  IN/WC
Uo TOTAL                          :         6.7800  BTU/HR-FT2-F
GAS VELOCITY                      :        35.0447  FT/SEC
TUBE PRESSURE DROP                :         5.8323  PSI
LMTD                              :       168.8029  DEG F
WATER VELOCITY                    :         4.4501  FT/SEC
MAX FIN TEMPERATURE               :       429.5960  DEG F
Hi                                :     1,635.5940  BTU/HR-FT2-F
MINIMUM TUBE TEMPERATURE          :       237.0859  DEG F
WEIGHT DRY                        :    10,560.3800  LBS
WEIGHT WET                        :    11,790.7900  LBS
LENGTH                            :        13.0000  FEET
WIDTH                             :         3.9167  FEET
HEIGHT                            :         7.2083  FEET
==========================================================================
TOTAL NUMBER OF COMPUTED ROWS                     :       13.0000
==========================================================================
                 Nebraska Boiler Company - Lincoln
```

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 3

Potential Discharge Basis

(Attachment AB-2)

Potential emissions are based on the current definition contained in Rule 17-2.100(168), F.A.C. and the use of natural gas and low sulfur fuel oil. Emission estimates were obtained as described in Attachment AB-1.

FPC is requesting use of the auxiliary boiler for no more than a total of 100 hours per year when fired on either low sulfur fuel oil or natural gas. Worst case emission are estimated based on either natural gas or low sulfur fuel oil as noted.

Nitrogen Oxides(1): (19.80 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.99 TPY

Carbon Monoxide(2): (4.9 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.25 TPY

Volatile Organic Compounds(1): (0.99 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.05 TPY

Particulate Matter(1): (4.9 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.25 TPY

Sulfur Dioxide(1): (5.27 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.26 TPY

Benzene(2): (0.0067 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.0003 TPY

Formaldehyde(2): (0.022 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.0011 TPY

Trace Metals(1): (0.26 lbs/hr)(100 hrs/yr)(T/2000 lbs) = 0.0130 TPY

Notes

(1) Low sulfur fuel oil combustion

(2) Natural gas combustion

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 5

Control Efficiency Derivation

(Attachment AB-3)

FPC has proposed use of dry low NO^x burners and low sulfur fuel oil as BACT. The low NO_x burners reduce nitrogen oxide emission by approximately 25% when fired on natural gas. Use of a low sulfur fuel oil (0.05% by weight) will reduce sulfur dioxide emissions by approximately 90%.

Nitrogen Oxides

Natural Gas: (1 - 9.9/13.15) (100) = 24.72% vs AP-42

Sulfur Dioxides

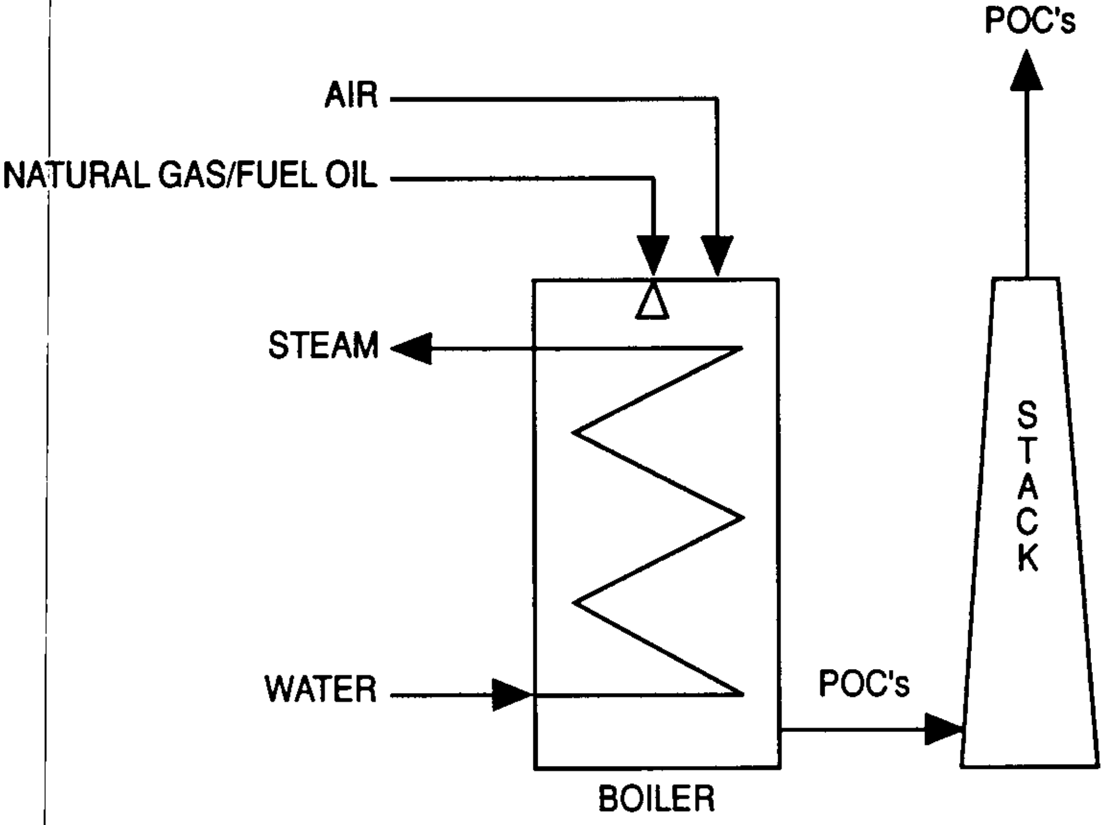
Natural Gas: N/A
Fuel Oil: (1 - 0.05/0.50) (100) = 90% versus NSPS Subpart Dc.

SECTION V: SUPPLEMENTAL REQUIREMENTS

ITEM 6

Flow Diagram

(Attachment AB-4)



LEGEND

POCs - PRODUCTS OF COMBUSTION

SOURCE: EBASCO ENVIRONMENTAL 1992

NOT TO SCALE

Florida Power CORPORATION

Polk County Site

FIGURE 2
SIMPLIFIED FLOW CHART

99mm Btu/hr Auxiliary Boiler

ADDITIONAL CERTIFICATIONS

(Attachment AB-5)

ADDITIONAL CERTIFICATION

This is to certify that the engineering features of the BACT analysis, and auxiliary boiler performance parameters of this FPC Polk County site 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 the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with the PSD air permit application.

Signed Charles J Schutty

Charles J. Schutty
Name (Please Type)

Black & Veatch Engineers
Company Name (Please Type)

11401 Lamar, Overland Park, KS 66211
Mailing Address (Please Type)

Florida Registration No. 43646 Date: 7/30/92 Telephone No. (913) 339-2369

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR THE FLORIDA POWER CORPORATION (FPC) POLK COUNTY SITE

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FIGURES

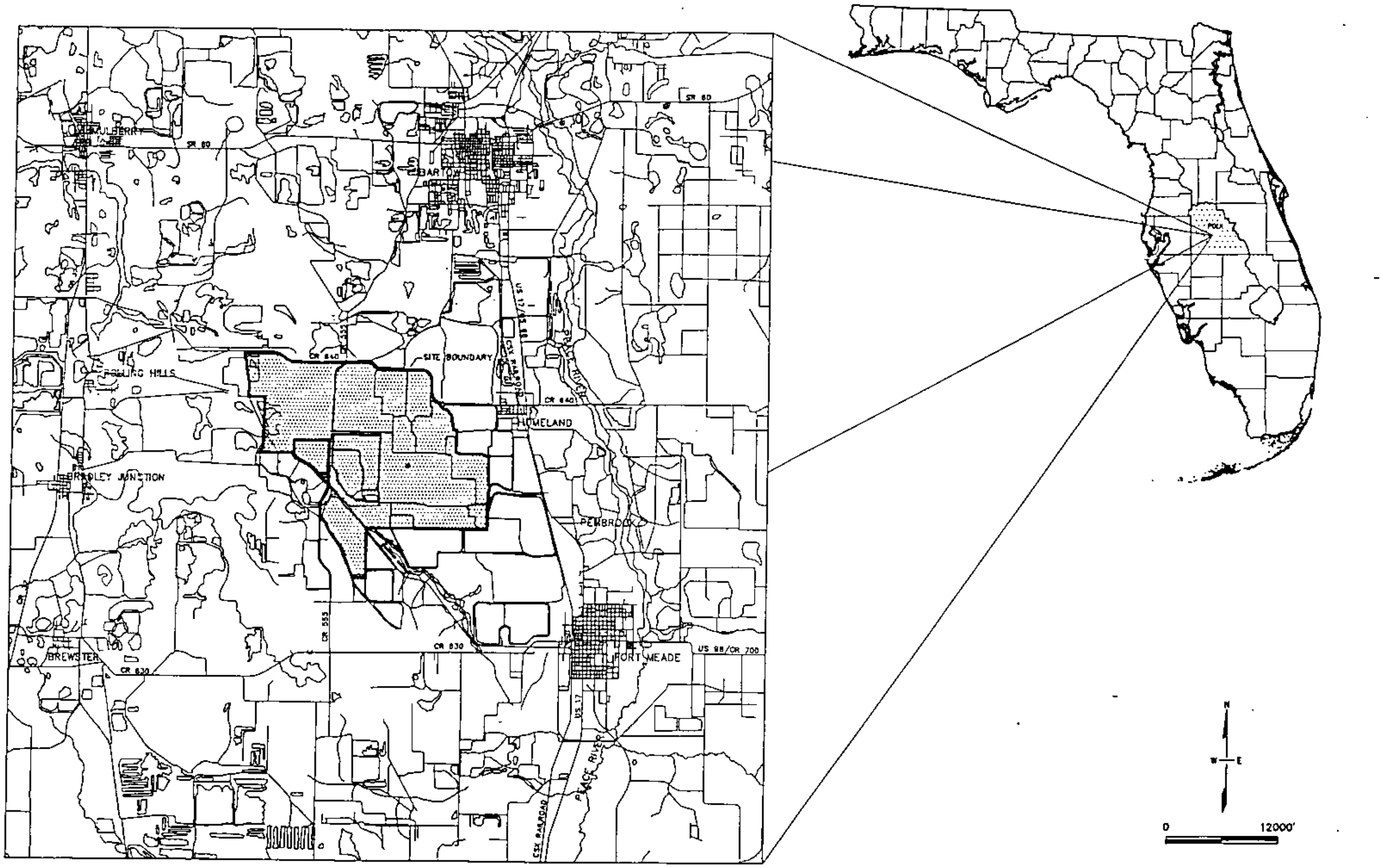
1.0 INTRODUCTION

Florida Power Corporation (FPC) proposes to install and operate multiple generating units at the Polk County Site beginning in 1998. The generating units will be located in the southwest portion of Polk County, about seven miles south-southwest of Bartow and five miles west-northwest of Fort Meade (see Figure 1-1). The generating units are to be brought on-line sequentially, with the scheduling of units to match the estimated growth of demand through the ultimate site capacity of up to 3,200 megawatts (MW). The expansion of generating capacity at the Polk County Site will be accomplished using the most cost-effective fuel and state-of-the-art generating technology throughout the life of the project. This approach offers FPC maximum flexibility and cost control as both technology advances and electrical demand increases.

The initial phase of the project is to provide approximately 940 MW and will consist of four 235 MW natural gas-fired combined cycle (CC) generating units capable of converting to a coal-derived gas in the future. An alternate configuration may consist of two 470 MW natural gas-fired CC generating units also capable of converting to coal-derived gas in the future. Low sulfur fuel oil will be used as the back-up fuel for this initial phase of the project. This application is only for the initial 940 MW phase of the project. Later generating units will be added as needed up to the 3,200 MW of ultimate site capacity. These later generating units will be optimized with the same fuel flexibility and may include pulverized coal (PC) units. At the present time, natural gas prices are projected to remain competitive beyond the end of the decade. In the future, coal is expected to be a more cost-effective fuel. Among the advantages of CC technology are its fuel flexibility, modularity, and efficiency. Should coal become the more economical fuel, the CC units will be capable of converting to burn coal-derived gas. Because of the modularity of CC units, they can be sized and built incrementally to match demand without losing the economy of scale. PSD applications for the remaining site capacity will be submitted in the future, where appropriate.

The U.S. Environmental Protection Agency (EPA) has promulgated Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21), which require a permit review and approval for new or modified existing sources that increase air pollutant emissions above specified threshold levels. These emission threshold levels will be exceeded during the initial phase of the project. As a result, the project is subject to PSD review. The Federal PSD regulations are implemented, through EPA approval of Florida's PSD program authority, by the Florida Department of Environmental Regulation (FDER). FDER's PSD regulations are codified in the

Florida Administrative Code (F.A.C.) Chapter 17-2.500. The completed FDER application forms for the initial phase (940 MW) of the project are attached to the front of this document. The technical information and analysis required by the federal and state PSD regulations are contained in this PSD permit application. Although this document will become an appendix to the Site Certification Application (SCA) for the proposed facility, it has been prepared as a stand-alone PSD permit application. The permit application is divided into eight major sections. Presented in Section 2.0 is a description of the facility, including air pollutant emissions and stack parameters. Air quality review requirements and applicability are presented in Section 3.0. The best available control technology (BACT) evaluation is presented in Section 4.0. An ambient air quality monitoring data analysis is presented in Section 5.0, and the air quality modelling methodology, the results of the air quality impact assessment, and additional air quality analyses performed for the proposed project are presented in Sections 6.0, 7.0, and 8.0, respectively. Section 9.0 contains a list of references and materials cited.



SOURCE: DAMES & MOORE, 1992

Florida Power
CORPORATION

Polk County Site

FIGURE 1-1
SITE LOCATION MAP

FPC/PSD

Rev. 0
8/92

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The proposed project will consist of the construction of approximately 940 MW of generation (four 235 MW CC units). Each CC unit will consist of a combustion turbine (CT), a heat recovery steam generator (HRSG), and a steam turbine for a total of four CTs, four HRSGs, and four steam turbines. An alternate configuration would consist of two 470 MW CC units. In this configuration each CC unit would consist of two CTs, two HRSGs, and one steam turbine. In either case, each CT will be served by a single HRSG, exhausting to an individual stack. There will be no HRSG bypass stacks for simple cycle operation. Also, there will be no supplemental firing of the HRSGs. The expected primary fuel is natural gas, with low sulfur fuel oil as a backup. An auxiliary boiler and emergency diesel generator will also be installed. A coal gasification facility may serve as a future source of fuel for the CC units; however, coal gasification is not a part of this PSD application.

The CC units will utilize low sulfur fuel to limit sulfur dioxide (SO_2) emissions and sulfuric acid mist, dry-low NO_X combustors to limit emissions of oxides of nitrogen (NO_X), and good combustion practices and clean fuels for the minimization of particulate matter, carbon monoxide (CO), volatile organic compounds (VOCs), and other (trace metals) emissions. The proposed emission control techniques are described in detail in Section 4.0 of this application.

2.2 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated stack emissions and exhaust parameters that are representative of the advanced CT designs (Black & Veatch, 1992) currently being considered for the project are presented in Tables 2-1 and 2-2 for a 235 MW CC unit. These tables cover the natural gas and fuel oil cases for three ambient temperatures: 40°F, 72°F, and 95°F. Tables 2-3 and 2-4 contain stack and emission data for the auxiliary boiler and diesel generator, respectively. Maximum annual potential emission rates (after the application of BACT) for the proposed sources with respect to regulated criteria air pollutants and regulated noncriteria air pollutants are presented in Table 2-5. Although a number of these pollutants (primarily the air toxics) are no longer subject to PSD review according to EPA's Clean Air Act Transition Guidance (EPA, 1991), it is understood that FDER will continue to consider these pollutants to be subject to PSD review.

Worst-case air quality impacts due to the proposed facility are a function of emission rate and plume rise. Although it is not practical to model all possible operating scenarios for the facility, a number of cases (combinations of operating conditions and fuel types) were examined to represent the range that will occur during actual operations. The low (40°F) and high (95°F) ambient temperatures are reasonable points selected to indicate the influence of compressor inlet temperature on combustion turbine performance and emissions/exhaust characteristics. CC units may operate at temperatures outside this range for short periods of time during a given year. The 72°F temperature case represents annual average temperature conditions for the Polk County Site.

A review of the CC unit design information in Tables 2-1 and 2-2 indicates that highest criteria air pollutant (SO_2, PM, NO_X, CO, VOC, and Pb) emission rates occur when burning fuel oil. Combustion of natural gas and fuel oil result in similar exhaust gas flow rates and stack exit temperatures, which are directly related to plume rise. Although the highest emission rates occur under the low temperature (40°F) condition, the lowest exhaust gas volumetric flow rate for the CC units occurs under the 95°F ambient temperature condition. Since this low exhaust flow condition results in potentially higher impacts due to lower plume rise of the exhaust gases than the 40°F ambient temperature case, combustion of natural gas and fuel oil under the 95°F ambient temperature condition were also evaluated in the air quality impact analysis. Thus, both conditions were evaluated as well as an average temperature case to determine the worst-case operating scenario.

Typical fuel analyses for natural gas and fuel oil are presented in Tables 2-6 and 2-7, respectively.

2.3 SITE LAYOUT AND STRUCTURES

Figure 2-1 depicts the site in relation to its surroundings and the location of the plant island on the site.

The plant island in this site configuration consists of land parcels designated as SA-11, SA-12, and SA-13. Equipment, such as combustion turbines, electrical generators, heat recovery steam generators, steam turbine generators, the diesel generator, and the auxiliary boiler, in addition to water and wastewater treatment facilities, will be located in the parcel designated as SA-11 referred to as the power block. The CC units will be situated in the northern portion of parcel SA-11, while water and wastewater treatment facilities and oil tanks will be south of the CC units. An ancillary facility, the storm water retention pond, will be located in the southern portion of parcel SA-12 to take advantage of existing topography. Rail access will be located in the northern portion of parcel SA-12 and also parcel SA-13. The main plant access road and electrical transmission line corridor will be located in parcel SA-13.

The site arrangement for the initial 940 MW is depicted in Figure 2-2. This alternate configuration arrangement includes two 470 MW CC units, each with two CTs, two HRSGs, and one steam turbine. The four HRSG stacks are arranged in an east-west line. The details of a single 235 MW CC unit are depicted in Figure 2-3.

TABLE 2-1
COMBINED CYCLE UNIT (235MW)
ESTIMATED (1) PERFORMANCE ON NATURAL GAS

CONDITIONS			
Ambient Temperature (°F)	40	72	95
Ambient Relative Humidity (%)	70	80	48
Load Condition (%)	100	100	100
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (mmBtu/hr)(2)	1,572.5	1,451.9	1,358.3
EMISSIONS (lb/hr)			
Carbon Monoxide (25 ppm)	80	73	70
Nitrogen Oxides (at 15% O_2) (12 ppm)(3)	76	70	65
Sulfur Dioxide	1.03	0.951	0.89
Particulate Matter (PM_{10})	9	9	9
Volatile Organic Compounds	11.2	10.4	9.6
Lead	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.
Sulfuric Acid Mist	0.11	0.0995	0.0931
Hydrogen Sulfide	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.
Benzene (4)	0.107	0.0987	0.0924
Inorganic Arsenic	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.
STACK PARAMETERS			
Stack Height (ft)	113	113	113
Stack Diameter (ft)	13.5	13.5	13.5
Stack Gas Temperature (°F)	200	200	200
Stack Gas Exit Velocity (ft/sec)	116	109	103

Notes:
(1) Emission estimates based on manufacturer's data (Black & Veatch, 1992).
(2) For CT's the heat input rate is based on the lower heating value of the fuel (918 Btu/SCF).
(3) Not corrected to ISO conditions.
(4) Benzene emission estimates from U.S. EPA (1988) based on natural gas combustion in a boiler.

MSL = Mean Sea Level

Neg. = Negligible

Source: Black & Veatch, 1992

TABLE 2-2
COMBINED CYCLE UNIT (235MW)
ESTIMATED (1) PERFORMANCE ON FUEL OIL

<u>CONDITIONS</u>			
Ambient Temperature (°F)	40	72	95
Ambient Relative Humidity (%)	70	80	48
Load Condition (%)	100	100	100
Elevation (ft) (above MSL)	163	163	163
Maximum Heat Input Rate (mmBtu/hr)(2)	1,799.8	1,644.5	1,532.8
<u>EMISSIONS</u> (lb/hr)			
Carbon Monoxide (30 ppm)	96	89	84
Nitrogen Oxides (at 15% O_2) (42 ppm)(3)	318	291	271
Sulfur Dioxide	98	90	83
Particulate Matter (PM_{10})	17	17	17
Volatile Organic Compounds	12	11.2	10.4
Lead (4)	0.016	0.0146	0.0136
Asbestos	Neg.	Neg.	Neg.
Beryllium (4)	0.00450	0.0041	0.00383
Mercury (4)	0.00540	0.0049	0.00460
Vinyl Chloride	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.
Sulfuric Acid Mist	10	9	8
Hydrogen Sulfide	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.
Inorganic Arsenic (4)	0.00756	0.00691	0.00644
Radionuclides	Neg.	Neg.	Neg.
<u>STACK PARAMETERS</u>			
Stack Height (ft)	113	113	113
Stack Diameter (ft)	13.5	13.5	13.5
Stack Gas Temperature (°F)	260	260	260
Stack Gas Exit Velocity (ft/sec)	133	124	117

Notes:
(1) Emission estimates based on manufacturer's data (Black & Veatch, 1992).
(2) For CT's the heat input rate is based on the lower heating value of the fuel.
(3) Not corrected to ISO conditions.
(4) Emission estimates from U.S. EPA (1989).

MSL = Mean Sea Level

Neg. = Negligible

Source: Black & Veatch, 1992

TABLE 2-3
AUXILIARY BOILER
ESTIMATED (1) PERFORMANCE ON NATURAL GAS & FUEL OIL

CONDITIONS	Natural Gas	Fuel Oil
Ambient Temperature (°F)	72	72
Ambient Relative Humidity (%)	80	80
Load Condition (%)	100	100
Elevation (ft) (above MSL)	163	163
Maximum Heat Input Rate (mmBtu/hr)	99.0	99.0
EMISSIONS (lb/hr)		
Carbon Monoxide	4.9	4.9
Nitrogen Oxides	9.9	19.8
Sulfur Dioxide	0.0641	5.27
Particulate Matter (PM_{10})	0.5	4.9
Volatile Organic Compounds	0.5	0.99
Lead (2)	Neg.	0.000881
Asbestos	Neg.	Neg.
Beryllium (2)	Neg.	0.000250
Mercury (2)	Neg.	0.000300
Vinyl Chloride	Neg.	Neg.
Total Fluorides	Neg.	Neg.
Sulfuric Acid Mist	0.00099	0.082
Hydrogen Sulfide	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.
Benzene (3)	0.00673	Neg.
Inorganic Arsenic (2)	Neg.	0.000415
Radionuclides	Neg.	Neg.
STACK PARAMETERS		
Stack Height (ft)	60	60
Stack Diameter (ft)	2.5	2.5
Stack Gas Temperature (°F)	332	329
Stack Gas Exit Velocity (ft/sec)	109	106

Notes:
(1) Emission estimates based on manufacturer's data (Black & Veatch, 1992).
(2) Emission estimates from U.S. EPA (1989).
(3) Emission estimates from U.S. EPA (1988) based on natural gas combustion in a boiler.

MSL = Mean Sea Level

Neg. = Negligible

Source: Black & Veatch, 1992

TABLE 2-4
DIESEL GENERATOR (1)
ESTIMATED (2) PERFORMANCE ON FUEL OIL

CONDITIONS	
Ambient Temperature (°F)	72
Ambient Relative Humidity (%)	80
Load Condition (%)	100
Elevation (ft) (above MSL)	163
Maximum Heat Input Rate (mmBtu/hr)	17.38
EMISSIONS (lb/hr)	
Carbon Monoxide	12
Nitrogen Oxides	53
Sulfur Dioxide	0.91
Particulate Matter (PM_{10})	0.48
Volatile Organic Compounds	0.27
Lead (3)	0.00016
Asbestos	Neg.
Beryllium (3)	0.000044
Mercury (3)	0.000052
Vinyl Chloride	Neg.
Total Fluorides	Neg.
Sulfuric Acid Mist	0.014
Hydrogen Sulfide	Neg.
Total Reduced Sulfur	Neg.
Benzene	Neg.
Inorganic Arsenic (3)	0.000073
Radionuclides	Neg.
STACK PARAMETERS	
Stack Height (ft)	25
Stack Diameter (ft)	1.5
Stack Gas Temperature (°F)	980
Stack Gas Exit Velocity (ft/sec)	143

Notes:
(1) Generator is rated at 1,300 kW.
(2) Emission estimates based on manufacturer's data (Black & Veatch, 1992)
(3) Emission estimates from U.S. EPA (1989).

MSL = Mean Sea Level

Neg. = Negligible

Source: Black & Veatch, 1992

TABLE 2-5
MAXIMUM POTENTIAL ANNUAL EMISSIONS (940 MW) AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions (TPY) *	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	1,418	100	Yes
Nitrogen Oxides	1,574	40	Yes
Sulfur Dioxide	115	40	Yes
Particulate Matter (PM_{10})	166	15	Yes
Total Suspended Particulates (TSP)	166	25	Yes
Volatile Organic Compounds	197	40	Yes
Lead	0.016	0.6	No
Asbestos	Neg.	0.007	No
Beryllium	0.0045	0.0004	Yes
Mercury	0.0054	0.1	No
Vinyl Chloride	Neg.	1	No
Total Fluorides	Neg.	3	No
Sulfuric Acid Mist	11.8	7	Yes
Hydrogen Sulfide	Neg.	10	No
Total Reduced Sulfur	Neg.	10	No
Benzene	1.9	Any	Yes
Inorganic Arsenic	0.0076	Any	Yes
Radionuclides	Neg.	Any	No

* TPY = Tons per year Neg. = Negligible
Any = Any emissions are considered significant

Basis: Full-load operation; 100% capacity factor; 40°F temperature; 500 hours on fuel oil, 8,260 hours on gas (except benzene emissions based on 8,760 hours on gas since emissions are higher on gas than fuel oil). The auxiliary boiler and diesel generator emissions are not included since they will not operate at the same time as the CC units except during start-up and for brief periods of testing.

Source: Black & Veatch, 1992

TABLE 2-6
TYPICAL NATURAL GAS ANALYSIS

Analysis	Mole (%)
Carbon Dioxide	0
Ethane	9.665
Hexanes Plus	0.05
Iso-Butane	0.19
Methane	85.76
Nitrogen	0.5
Normal-Butane	0.24
Pentanes Plus	0.09
Propane	3.505
Total:	100.000
Specific Gravity (air at 1)	0.71

Quality Information	Parameters
Heating Value (LHV)	918 Btu/SCF
Total Sulfur (Maximum)	2,000 grains/mmSCF

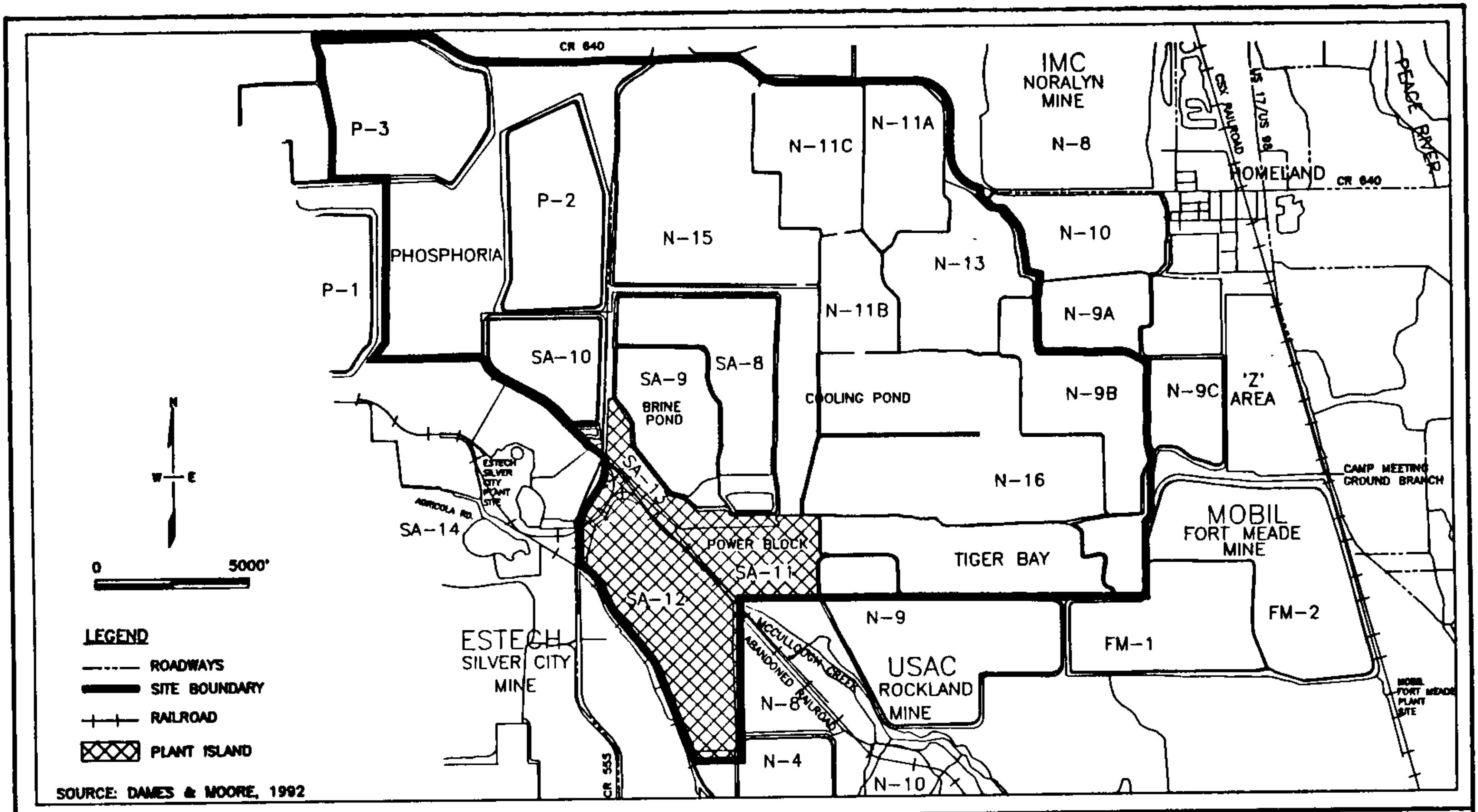
Source: Florida Gas Transmission

TABLE 2-7
TYPICAL FUEL OIL ANALYSIS

Distillate Oil	Weight (Percent)
Carbon	85.46
Hydrogen	13.43
Nitrogen	0.015
Oxygen	1.51
Sulfur	0.05 *
Ash	0.01

Lower Heating Value: 18,550 Btu/lb
Higher Heating Value: 19,200 Btu/lb

* The sulfur content is "low" rather than "typical" and other values have been scaled.

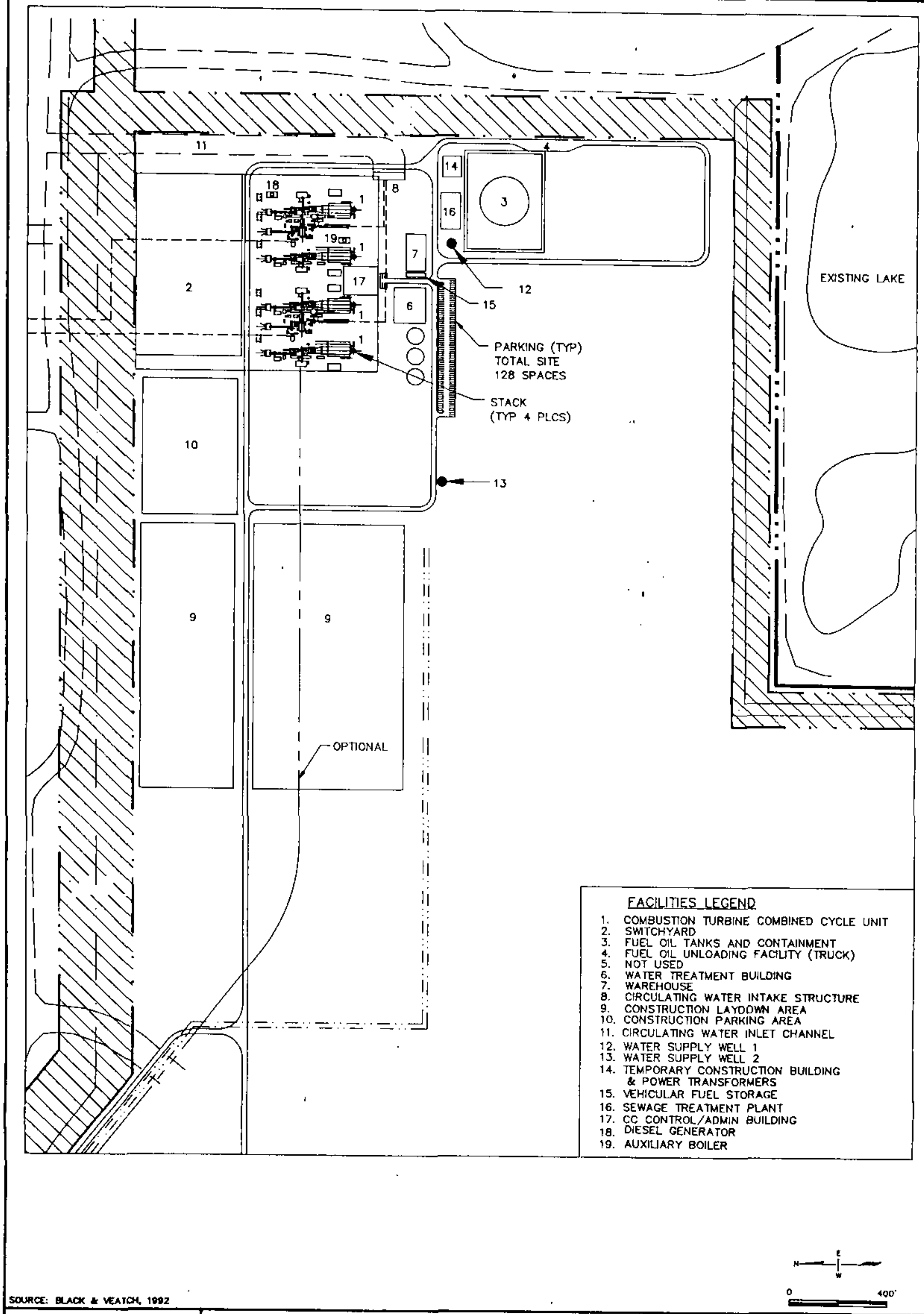


SOURCE: DAMES & MOORE, 1992

Florida Power
CORPORATION

Polk County Site

FIGURE 2-1
SITE BOUNDARY



FACILITIES LEGEND

1. COMBUSTION TURBINE COMBINED CYCLE UNIT
2. SWITCHYARD
3. FUEL OIL TANKS AND CONTAINMENT
4. FUEL OIL UNLOADING FACILITY (TRUCK)
5. NOT USED
6. WATER TREATMENT BUILDING
7. WAREHOUSE
8. CIRCULATING WATER INTAKE STRUCTURE
9. CONSTRUCTION LAYDOWN AREA
10. CONSTRUCTION PARKING AREA
11. CIRCULATING WATER INLET CHANNEL
12. WATER SUPPLY WELL 1
13. WATER SUPPLY WELL 2
14. TEMPORARY CONSTRUCTION BUILDING & POWER TRANSFORMERS
15. VEHICULAR FUEL STORAGE
16. SEWAGE TREATMENT PLANT
17. CC CONTROL/ADMIN BUILDING
18. DIESEL GENERATOR
19. AUXILIARY BOILER

SOURCE: BLACK & VEATCH, 1992

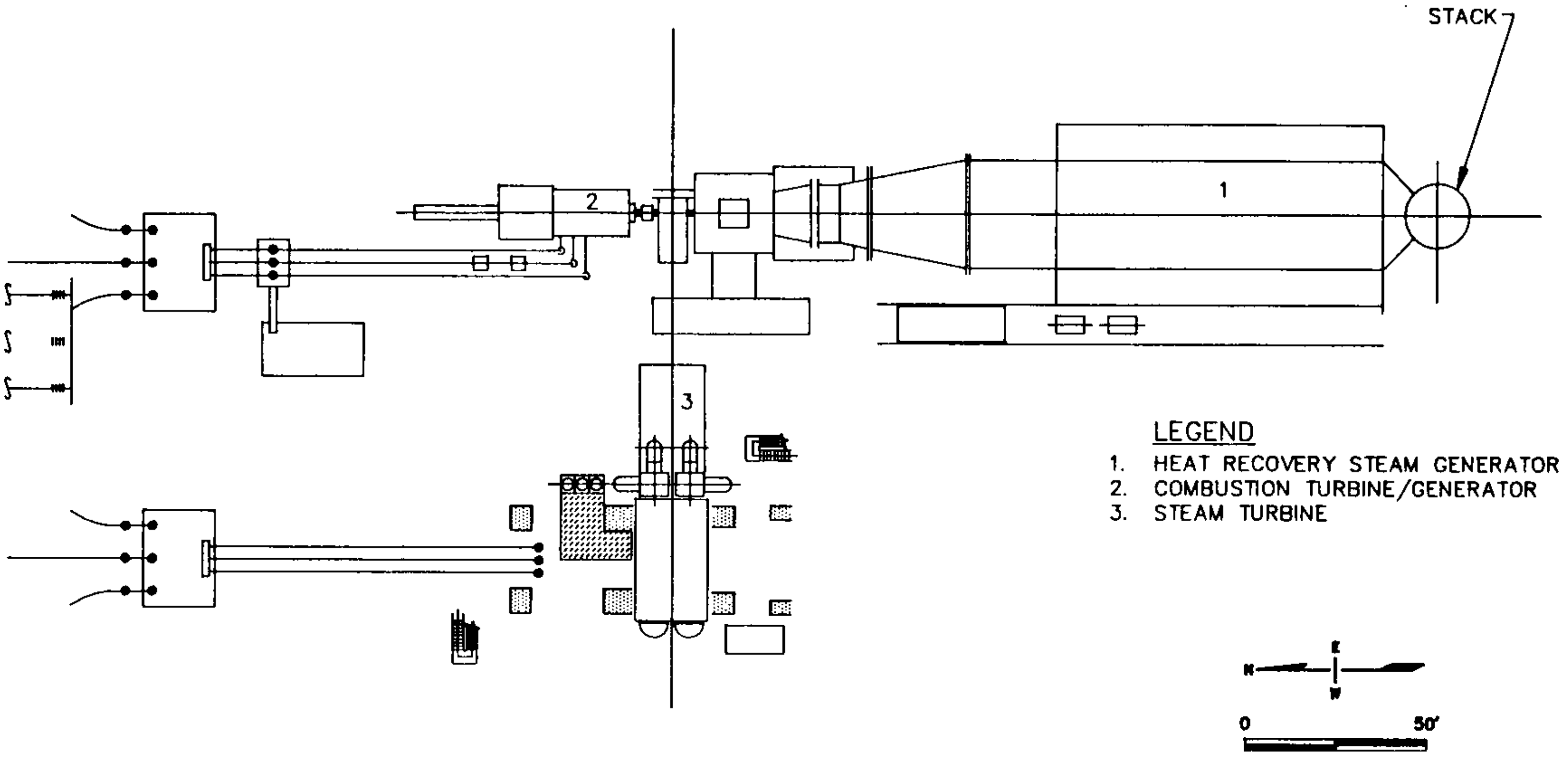
Florida Power CORPORATION

Polk County Site

FIGURE 2-2
SITE ARRANGEMENT
(940 MW)

FPC/SCA

FPC Polk County Site



SOURCE: BLACK & VEATCH, 1992

Florida Power
CORPORATION

Polk County Site

FIGURE 2-3
LAYOUT FOR ONE CC UNIT
(235 MW)

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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 project. These regulations must be satisfied before the proposed facility can be constructed and begin operation.

3.1 NATIONAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS (NAAQS/FAAQS)

The applicable federal and state ambient air quality standards are presented in Table 3-1 (PSD increments are also presented in Table 3-1, but discussed in Section 3.2.2). The primary NAAQS/FAAQS were promulgated to protect the public health, and the secondary NAAQS/FAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Polk County is an attainment area for all criteria pollutants, meaning that existing concentrations are within the allowable limits.

3.2 PSD REVIEW REQUIREMENTS

3.2.1 General Requirements

Under the federal and FDER PSD permit review requirements, all major new or modified existing sources of air pollutants located in attainment areas and regulated under the Clean Air Act (CAA) must be reviewed and approved. A "major stationary source" is defined as any one of 28 specified source categories which has the potential to emit 100 TPY or more, or any other stationary source which has the potential to emit 250 TPY or more of any air pollutant regulated under the CAA. Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr of heat input comprise one of the 28 specified source categories. Thus, this project is subject to the 100 TPY cutoff. The term "potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. The emissions from the proposed project will exceed the 100 TPY criteria. Therefore, the project is considered a major stationary source and subject to PSD review.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source located in an attainment area. The PSD regulations are contained in Ch. 17-2.500 F.A.C. Major sources and modifications are required to undergo the following analyses under PSD for each air pollutant emitted in significant quantities:

- A control technology analysis;
- An air quality impacts analysis; and
- An additional impacts analysis.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations (EPA, 1985a), NSPS, and any state emission standard as discussed in Section 3.3.

3.2.2 PSD Increments/Classifications

In promulgating the 1977 Clean Air Act (CAA) Amendments, Public Law 95-95, Congress specified that certain increases above an air quality "baseline concentration" level for SO_2 and 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 designated PSD areas as Class I (international parks, 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 allow greater deterioration than Class II areas, were designated. EPA subsequently incorporated the requirements for classifications and area designation into the PSD regulations.

On October 17, 1988, the EPA promulgated regulations to prevent significant deterioration due to NO_X emissions and established PSD increments for NO_2 concentrations. The allowable PSD increments for SO_2, TSP, and NO_2 were presented in Table 3-1. The FDER has adopted the EPA PSD classification scheme and the allowable PSD increments for SO_2, TSP, and NO_2.

The term "baseline concentration" is derived from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and contributions from certain additional baseline sources. The PSD regulations (40 CFR 52.21) define baseline concentration as the ambient concentration level which exists in the baseline area at the time of the applicable baseline date. Emission increases after the baseline date consume PSD increments. A baseline concentration is determined for each pollutant for which PSD increments are promulgated and a baseline date is established. The baseline concentration includes:

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

The air quality analysis results which demonstrate project compliance with these requirements are presented in Section 7.0.

3.2.3 Control Technology Review

The control technology review requirements of the 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. The BACT requirements apply to all applicable regulated and unregulated air pollutants for which the increase in emissions from the source or modification exceeds significant emission levels.

BACT is defined in F.A.C. 17-2.100 as:

> An emission limitation, including a visible emissions 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 each 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.

> Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

The requirements for BACT were incorporated within the PSD framework in the 1977 CAA Amendments. The primary purpose of BACT is to minimize consumption of PSD increments and thereby increase the potential for future economic growth without significantly degrading air quality. Guidelines for the evaluation of BACT can be found in the draft "New Source Review Workshop Manual" (EPA, 1990b) and the draft "Top-Down BACT Guidance Document" (EPA, 1990c). These guidelines were issued 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. Although the "top-down" approach to BACT has been suspended by EPA as a result of a suit settlement until formal rulemaking is undertaken, it is understood that FDER is still requesting that this approach to BACT be used. BACT is determined on a case-by-case basis, and BACT for a source in one area may not be the same for an identical source located in another area. BACT analyses for the same types of emissions units 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.

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, at a minimum, demonstrate compliance with 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 determination of BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts. Section 4.0 presents the BACT for this project.

3.2.4 Ambient Air Quality Monitoring Requirements

In accordance with the requirements of Ch.17-2.500(5)(f) F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality monitoring data in the area affected by the proposed major stationary source or major modification.

According to EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA, 1987), ambient air monitoring for a period of up to one year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of four months of data are required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

The PSD regulations include an exemption which excludes or limits the pollutants for which an ambient air quality analysis must be conducted. This exemption states that the Department may exempt a proposed major stationary source or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the *de minimis* air quality impact levels presented in Table 3-2.

FPC's air quality monitoring program is discussed in Section 5.0 of this application.

3.2.5 Source Impact Analysis

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate. The PSD regulations specifically require the use of atmospheric dispersion models in performing air quality impact analysis, estimating baseline and future air quality levels, and determining compliance with NAAQS/FAAQS and allowable PSD increments. Reference EPA models must normally be used in performing the impact analysis. Use of nonreference EPA models requires EPA's consultation and prior approval. Guidance for the regulatory application of dispersion models is presented in the U.S. EPA "Guideline on Air Quality Models (Revised)" (EPA, 1990a). The modelling methodology utilized for the source impact analysis is described in detail in Section 6.0 of this application.

3.2.6 Additional Impacts Analysis

In addition to air quality impact analyses, the 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. These analyses are to be conducted primarily for PSD Class I areas. Impacts on air quality due to general commercial, residential, industrial, and other growth related activities associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant quantities. Section 8.0 of this application contains the additional impact analyses.

3.3 OTHER REQUIREMENTS

In addition to the requirements of the PSD program, any new or modified source of air pollution must be reviewed with respect to the GEP stack height regulations (EPA, 1985a), the federal NSPS requirements, and any state-specific emission standards.

3.3.1 Good Engineering Practice (GEP) Stack Height

The 1977 CAA Amendments require under Section 123 that the degree of emission limitation required for control of any air 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).

The EPA's final stack height regulations define GEP stack height in part as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack; or

(2) $H_g = H + 1.5 L$

where:

H_g = GEP stack height, measured from the ground-level elevation at the base of the stack;

H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack; and

L = Lesser dimension, height or projected width of nearby structure(s).

The term "nearby" is defined by the GEP stack height regulations 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 km. Although GEP stack height regulations require that the stack height credit used in modelling for determining compliance with NAAQS/FAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. In this case the proposed stacks for the 940 MW generating units are 112.8 feet (34.4 meters) above ground level. GEP stack height as determined by the BREEZE WAKE program (Trinity Consultants, 1989) is estimated at 150 feet (45.72 meters). See Section 6.7 of this application for a discussion of building downwash considerations for this project.

3.3.2 New Source Performance Standards (NSPS)

The CAA required the U.S. EPA to adopt standards of performance for new or modified stationary sources of air pollution. To date, the U.S. EPA has adopted regulations for approximately 60 stationary source categories. These regulations are contained in 40 CFR Part 60. A review of the regulations reveals that the CC units, the auxiliary boiler, and the oil storage tanks may be subject to a specific NSPS. Any source subject to a specific NSPS is also subject to the general provisions of 40 CFR 60 Subpart A.

3.3.2.1 General Provisions

The general provisions of the NSPS regulations are found in 40 CFR 60, Subpart A. The general provisions specify the notification and recordkeeping requirements (40 CFR 60.7), compliance with standards and maintenance requirements (40 CFR 60.11), and the monitoring requirements (40 CFR 60.13) for each affected source.

3.3.2.2 Combined Cycle Units

In general, CC units are covered in 40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978; in 40 CFR 60, Subpart Db - Standards of Performance for 2 Industrial-Commercial-Institutional Steam Generating Units; and in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. Because of the nature of the proposed FPC CC unit operation, only the requirements of Subpart GG and Subpart A will apply.

Subpart GG regulates the CC units as electric utility stationary gas turbines and establishes emission limitations on both NO_x and SO_2. The NO_x emission limitation is set by the following equation:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined below:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
$N<0.015$	0
$0.015<N<0.1$	0.04(N)
$0.1<N<0.25$	0.004 + 0.0067(N-0.1)
$N>0.25$	0.005

where:

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

This results in an emission limitation of 153.15 parts per million on a dry volume basis (ppmvd) at 15 percent oxygen for the proposed units when fired on natural gas and 133.66 ppmvd at 15 percent oxygen when fired on fuel oil (These values do not include the allowance for fuel-bound nitrogen). The SO_2 emission limitations are set at 150 ppmvd corrected to 15 percent oxygen in the exhaust stream or a fuel sulfur content less than or equal to 0.8 percent by weight.

40 CFR 60 Subparts Da, Db, and Dc are not applicable to the CC units since the HRSGs will not be fired with any type of auxiliary fuel.

3.3.2.3 Auxiliary Boiler

The auxiliary boiler as proposed is to have a maximum heat input rate of less than 100 mmBtu/hr and will be fired on either natural gas or fuel oil (distillate). The auxiliary boiler is classified as a steam generating unit under the NSPS 40 CFR 60 Subparts D, Da, Db, and Dc. Due to the size of the auxiliary boiler, only the requirements of Subpart Dc will apply.

Subpart Dc establishes emission limitations on sulfur dioxide and particulate matter when the auxiliary boiler is fired on fuel oil. Subpart Dc does not establish any emission limits on the auxiliary boiler when it is fired on natural gas. When fired on fuel oil, sulfur dioxide emissions must not exceed 0.50 lb/mmBtu of heat input or, as an alternative, the oil must not have a sulfur content greater than 0.5 percent by weight. Particulate matter emissions are limited through a 20 percent opacity (6-minute) standard. The proposed auxiliary boiler must meet these limits except during periods of startup, shutdown, or malfunction.

3.3.2.4 Fuel Oil Storage Tanks

The fuel oil storage tanks will contain a volatile organic liquid as defined in 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. Because the fuel oil is expected to have a maximum true vapor pressure of less than 3.5 kilopascals (kPa), only the minor monitoring of operations requirements specified in 40 CFR 60, .116b(a) and (b) will apply.

3.3.2.5 Excess Emissions

The EPA has adopted general and specific recordkeeping and reporting requirements relating to excess emissions in 40 CFR 60.7(b) and 40 CFR 60.334(c). The EPA requirements specify maintaining records and submittal of a quarterly report (calendar year) on excess emissions associated with start-ups, shutdowns, malfunctions, inoperative continous emission monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the quarterly report even when no excess emissions occur. EPA has not adopted any specific time limits related to excess emissions from a CC unit, or from combustion turbine units regulated under 40 CFR Part 60, Subpart GG.

3.3.3 State-Specific and General Emission Standards

In addition to federal requirements, FDER has adopted specific and general emission limiting and performance standards. These standards may be found in Chapter 17-2, Part VI, of the F.A.C. The requirements of these standards must be met along with any federal PSD or NSPS limitation or requirement.

3.3.3.1 General Emission Standards

The FDER has adopted general particulate matter emission limits (Rule 17-2.610, F.A.C.) as well as general pollutant emission limits (Rule 17-2.620, F.A.C.). These limits apply when no specific emission standard is applicable.

3.3.3.2 Combined Cycle Units

The FDER has not adopted any state-specific emission standards in Rules 17-2.600 or 17-2.650, F.A.C. relating to the operation of a CC unit. The FDER has adopted the NSPS requirements of Subparts A and GG by reference in Rule 17-2.660, F.A.C. Based on the current FDER rules, the CC units must meet the NSPS requirements as discussed in Section 3.3.2.2. In addition, a general opacity limit of not greater than or equal to 20 percent opacity and a prohibition on emitting air pollutants that cause or contribute to an objectionable odor apply.

3.3.3.3 Auxiliary Boiler

The FDER has adopted a specific emission limiting standard in Rule 17-2.600(6), F.A.C. for fossil fuel steam generators with less than 250 mmBtu/hr of heat input. The rule sets a standard for opacity and requires the application of BACT for particulate matter and sulfur dioxide. The opacity standard is the same as the NSPS regulation.

3.3.3.4 Fuel Oil Storage Tanks

The FDER has adopted standards for petroleum liquid storage tanks in Rule 17-2.650, F.A.C. This rule applies only to sources located within an ozone nonattainment area. Since the oil storage tanks will not be located within an ozone nonattainment area, the tanks are not subject to the requirements of this rule. The oil storage tanks are subject to the requirements of

Rule 17-2.620, F.A.C., which requires the use of "known and existing vapor emission control devices or systems." In this case, FPC proposes the use of bottom loading/submerged filling as recommended.

3.3.3.5 Excess Emissions

The FDER has adopted standards relating to excess emissions in Rule 17-2.250, F.A.C. The rule allows excess emissions resulting from startup, shutdown, or malfunction of any source as long as best operational practices are applied and the excess emissions do not exceed 2 hours in any 24-hour period. Currently, the rule allows one exception from the 2-hour limit and that is for existing fossil fuel steam generators. The FDER can authorize different excess emission parameters from other sources on a case-by-case basis. Based on the intended operation of the CC units, it is requested that the FDER consider the operational variations of this equipment as well as the EPA's NSPS requirements on excess emissions adopted in Rule 17-2.660(3)(a), F.A.C., and set an allowable excess emissions level in accordance with Rule 17-2.250(5), F.A.C., as follows:

> "Excess emissions from a combined cycle unit resulting from startup, shutdown, malfunction, or load change shall be permitted provided that best operational practices to minimize excess emissions are adhered to and the duration of the excess emissions shall be minimized."

The auxiliary boiler is also subject to the FDER's excess emissions rule with general allowables for new fossil fuel-fired steam generators. Based on the intended operation of the auxiliary boiler, compliance with the rule should not impose any significant impact.

3.4 SOURCE APPLICABILITY

3.4.1 Pollutant Applicability

The PSD regulations apply to the proposed generation project due to the attainment status for the Polk County Site with respect to all criteria air pollutants. Polk County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The Polk County Site is located approximately 118 km southeast of the Chassahowitzka Wilderness Area, the nearest

PSD Class I area. The Chassahowitzka Wilderness Area is that portion of the Chassahowitzka National Wildlife Refuge which has been officially designated as wilderness.

Pollutant applicability for the proposed facilities is addressed in Sections 2.0 and 4.0 and briefly summarized here. The proposed project is considered to be a major source under the PSD regulations. PSD review is required for any regulated pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 2-5. As shown, the potential emissions for the proposed facilities will exceed the PSD significant emission rates for the following regulated pollutants: CO, NO_X, SO_2, PM_{10}, VOC, beryllium (Be), sulfuric acid mist, benzene, and inorganic arsenic (As). The proposed project is subject to PSD review for these pollutants.

3.4.2 Ambient Air Quality Monitoring

Based upon the net increase in emissions from the proposed facility presented in Table 2-5, a PSD preconstruction ambient air monitoring analysis is required, as part of the air quality impact analysis for CO, NO_2, SO_2, PM_{10}, O_3 (based on VOC emissions), Be, sulfuric acid mist, benzene, and As. However, if the net increase in a source's impact of a pollutant is less than the *de minimis* air quality impact level, as shown in Table 3-2, then an exemption from the preconstruction ambient air quality monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient air monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Prior to commencement of preconstruction ambient air quality monitoring, preliminary modelling was done to indicate those pollutants which could be exempted from the monitoring requirement. As verified by the revised modelling analysis described in Sections 6.0 and 7.0, the increases in air quality impacts for NO_2 and CO are predicted to fall below the *de minimis* impact levels presented in Table 3-2. There are no EPA approved PSD protocol ambient monitoring methods for As, Be, sulfuric acid mist, or benzene. Therefore, monitoring was not required for NO_2, CO, As, Be, sulfuric acid mist, and benzene. As a result, a preconstruction ambient monitoring analysis was performed for SO_2, PM_{10}, and O_3. The results for these pollutants are presented in Section 5.0.

TABLE 3-1
AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENTS

Pollutant	Averaging Time	Federal NAAQS ($\mu g/m^3$)	Florida FAAQS ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
CO	1-hour	40,000	40,000	NA	NA
	8-hour	10,000	10,000	NA	NA
NO_2	Annual	100	100	2.5	25
SO_2	3-hour	1,300 (1)	1,300 (1)	25	512
	24-hour	365	260	5	91
	Annual	80	60	2	20
PM (2)	24-hour	150	150	10	37
	Annual	50	50	5	19
O_3 (3)	1-hour	235	235	NA	NA
Pb	Calendar Quarter	1.5	1.5	NA	NA

(1) The 3-hour average SO_2 ambient air quality standard is a secondary (welfare-related) standard. All of the other federal and Florida ambient air quality standards are primary (health-related) standards.

(2) Ambient air quality standards are based on PM_{10} and PSD increments are based on total suspended particulates (TSP) until such a time as EPA promulgates PM_{10} PSD increments. On October 5, 1989, EPA proposed increments of 8 $\mu g/m^3$ (24-hr) and 4 $\mu g/m^3$ (annual) for Class I areas and 30 $\mu g/m^3$ (24-hr) and 17 $\mu g/m^3$ (annual) for Class II areas (FR, 1989).

(3) Ozone values are associated with emissions of VOCs.

Note: Short-term standards (i.e., those with averaging times less than annual) and increments can be exceeded once per year.

NA = No PSD increments exist for these pollutants.

Sources: 40 CFR 50; F.A.C. 17-2.300, F.A.C. 17-2.310

TABLE 3-2
PSD *DE MINIMIS* AMBIENT AIR QUALITY IMPACT LEVELS

Pollutant	Air Quality Impact *De Minimis* Level ($\mu g/m^3$) and Averaging Time (1)
Carbon Monoxide	575 (8-hour)
Nitrogen Dioxide	14 (Annual)
Sulfur Dioxide	13 (24-hour)
Particulate Matter (PM_{10})	10 (24-hour)
Particulate Matter (TSP)	10 (24-hour)
Volatile Organic Compounds (Ozone)	(2)
Lead	0.1 (3-month)
Asbestos	(3)
Beryllium	0.001 (24-hour)
Mercury	0.25 (24-hour)
Vinyl Chloride	15 (24-hour)
Total Fluorides	0.25 (24-hour)
Sulfuric Acid Mist	(3)
Hydrogen Sulfide	0.2 (1-hour)
Total Reduced Sulfur (including H_2S)	(3)
Benzene	(3)
Inorganic Arsenic	(3)
Radionuclides	(3)

(1) Ambient air quality monitoring requirements for applicable pollutants may be exempted if the impact of the net increase in emissions is below the applicable air quality impact *de minimis* levels.

(2) No specific air quality impact *de minimis* level is prescribed for ozone. Exemptions are granted when a proposed source's VOC emissions are less than 100 tons/year.

(3) No acceptable monitoring techniques available at this time. Therefore, monitoring is not required until acceptable techniques are available.

Source: F.A.C. 17-2.500(3)(e)1

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 INTRODUCTION

This section of the PSD application provides a detailed analysis of BACT options for the Polk County Site installation of four 235 MW CC units. The CC units will consist of one HRSG per CT and one steam turbine. An alternate configuration involves two 470 MW CC units consisting of two CTs, two HRSGs, and one steam turbine. The total generating capacity of the four CC units will be approximately 940 MW.

In addition to the CC units, the project will include an auxiliary boiler which may be fired on either natural gas or fuel oil to preheat the HRSGs and steam turbines during cold startup. The auxiliary boiler will be used only if all four CC units are shut down. Once one CC unit is operational, and steam from the operating unit's HRSG is used to preheat the other units, the auxiliary boiler will then be shut down. The project also will include an emergency diesel generator. The generator will be capable of providing 1,300 kW of electrical power and will be fired on fuel oil with a heat input rate of less than 18 mmBtu/hr. The generator will be used only for periods when in-plant power is lost.

The project's potential annual emissions of the following regulated pollutants exceed the PSD significant emission rate thresholds and are, therefore, subject to BACT review:

- Carbon Monoxide (CO)
- Nitrogen Oxides (NO_X)
- Sulfur Dioxide (SO_2)
- Particulate Matter (TSP and PM_{10})
- Volatile Organic Compounds (VOC)
- Beryllium (Be)
- Sulfuric Acid Mist (H_2SO_4)
- Benzene (C_6H_6)
- Inorganic Arsenic (As)

Consequently, this BACT analysis addresses the control of emissions of these pollutants. Also included are evaluations of the effects of the BACT systems selected on the emissions of other regulated pollutants emitted below *de minimis* levels and unregulated hazardous air pollutants.

This BACT analysis follows the general requirements of EPA's draft "top down" BACT guidance document (EPA, 1990c), which requires that the BACT analysis start by assuming the use of the most stringent control technology. Other less efficient emission control technologies are evaluated if the most stringent control technology is determined to be technologically infeasible or unreasonable considering economic, energy, and environmental factors. The economic analysis in this section is based on the criteria listed in Table 4-1.

4.2 REQUIREMENTS AND ASSUMPTIONS

This BACT analysis assumes that four CC units will be operating at an annual average inlet temperature of 72°F and an ambient relative humidity of 80 percent. These are the approximate annual average conditions at the site. In order to assure that conservatively high pollutant emission rates are used in the BACT analysis, the CC units are assumed to operate at 100 percent capacity, 8,760 hours per year. Natural gas will be the primary fuel and fuel oil will be the back-up fuel (no more than 500 hours per year).

The project will use the most technically advanced equipment available at the Polk County Site. The CTs will be equipped with dry low NO_X combustors capable of limiting NO_X emissions to the lowest levels possible without using water for combustion control while firing natural gas. The dry low NO_X technology is particularly valuable for CC facilities where it is beneficial to keep water usage to a minimum. By using technically advanced equipment such as the dry low NO_X combustors, the Polk County Site will be able to reduce pollutant emissions to levels well below those currently required, while using pollution control technologies which conserve valuable natural resources and do not require potentially hazardous chemicals, such as vanadium and gaseous ammonia.

As proposed, Phase I of the project has been designed around the use of dry low NO_x combustion technology. A CC unit's cycle heat rate (BTU/kW-h) using standard combustors with water injection is approximately three percent higher than that of the proposed combustion technology. This three percent increase is directly related to the energy required to evaporate the water used to control the combustion temperature. Because of the water evaporated by a standard combustor utilizing water injection, the exhaust gas rate will be much higher than that of the proposed combustion technology. This increased exhaust gas rate has a direct impact on the design of the HRSG requiring a larger HRSG than would be required for that of the proposed combustion technology. Therefore, since dry low NO_x combustion technology has been an integral part of the overall project design, standard combustors are not considered further in this analysis.

4.3 NITROGEN OXIDES EMISSIONS

During combustion, two types of NO_X are formed: fuel NO_X and thermal NO_X. Fuel NO_X emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_X emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. Formation of nitrogen oxides can be limited by lowering combustion temperatures by staging combustion (a reducing atmosphere followed by an oxidizing atmosphere), or by post-combustion controls.

4.3.1 Alternative NO_X Emission Reduction Systems

A review of the latest control technology determinations (CARB, 1991 and 1992; EPA, 1985 and 1990) indicates that the lowest NO_X emission limit established to date for a CC unit equipped with a dry low NO_x combustor is 6 ppmvd. This is for a natural gas-fired CC unit located in an ozone nonattainment area in California. The 6 ppmvd emission limit was based on the use of dry low NO_X combustors in combination with a selective catalytic reduction (SCR) system. Therefore, the most stringent control technology for NO_X emissions control with a CC unit using dry low NO_X combustors is an SCR system. The only stationary sources required to meet this most stringent control technology emission limit are those new/modified sources being located in nonattainment areas or sources which have other unique circumstances which require exceedingly stringent pollution control.

SCR and other NO_X emission control technologies will be examined separately in the following paragraphs.

4.3.1.1 Selective Catalytic Reduction

SCR is a post-combustion method for control of NO_X emissions. The SCR process combines vaporized ammonia with NO_X in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed.

The performance and effectiveness of SCR systems is directly dependent on catalyst operating temperatures. The optimum flue gas temperature range for SCR operation is approximately 650° to 750°F. At temperatures lower than 600°F, the ammonia reaction rate with NO_X is low, resulting in large quantities of ammonia slip. At temperatures above about 800°F, permanent damage to the catalyst occurs.

Flue gas from a CT will typically range from 950°F to 1,100°F. Accordingly, an SCR device would be installed at an intermediate point of the HRSG after several rows of tubes, where a temperature of approximately 700°F occurs. The narrow SCR temperature window dictates that the SCR catalyst be precisely located in the HRSG. A recent report indicated that effective SCR operation becomes very difficult for units that see a variation in gas flow and temperature through the HRSG due to load changes or ambient temperature swings (Boericke, 1990). Another recent report indicates that maintaining the catalyst in the narrow SCR temperature window over the entire CC unit operating load range can be difficult (Shorr, 1991). Therefore, SCR performance will be difficult to maintain if the CC unit load varies or if significant temperature swings occur.

Catalyst NO_X reduction efficiency will be affected by the NO_X concentration at the SCR inlet. The reaction mechanism requires both NO_X and ammonia to occupy a catalytic reaction site at the same time. This is a random event. The lower the NO_X concentration, the less likely it is that any one ammonia particle and NO_X particle will meet on a reaction site. Therefore, as the SCR inlet concentration of NO_X decreases, the catalyst needs to become larger and/or the amount of ammonia added needs to be increased (leading to increased ammonia slip) for similar NO_X reduction efficiencies. The dry low NO_X combustors have relatively low NO_X emissions and will therefore require a greater volume of catalyst than a standard combustor would for the same NO_X removal efficiency.

Catalyst NO_X reduction efficiency also will be affected by the type of fuel being burned. When firing fuel oil, the SCR catalyst will oxidize approximately three percent of the SO_2 in the flue gas to SO_3. Catalytic reduction efficiency is therefore reduced when available reaction sites are occupied by sulfur compounds. Additionally, the ammonia present in the flue gas will react with the SO_3 to form ammonia sulfate salts and the water in the flue gas will react with the SO_3 to form sulfuric acid mist. The formation of ammonia sulfate salts will reduce the amount of ammonia available for reaction with the NO_X. Ammonium bisulfate, one of the ammonia salts formed, will also reduce a CC unit's thermal efficiency by coating the heat transfer surfaces of the HRSG and potentially limit unit availability due to forced outages for HRSG cleanup. Both the ammonia sulfate salts and the sulfuric acid mist will increase the amount of particulate matter emitted in the flue gas to a level of approximately 21 lbs/hr in the form of ammonium bisulfate (31 percent increase). This particulate will predominately consist of matter less than 10 microns in size (PM_{10}).

Catalyst life expectancy also can be affected by the type of fuel burned. Catalyst poisoning can be caused by such trace elements as arsenic, beryllium, cadmium, chromium, copper, lead, manganese, mercury, and nickel, all of which can be found in fuel oil. Arsenic, the major poison, can be deposited on catalyst surfaces in the form of gaseous arsenic oxide, which can clog the small pores of the catalyst and prevent the ammonia/nitrogen oxide mixture from being catalytically oxidized.

SCR systems are also relatively complex chemical reaction systems to operate and control. Continuous emissions monitoring (CEM) systems used to trim ammonia injection to minimize ammonia slip have proven unreliable and relatively insensitive to the low concentrations being measured. SCR system users cited by a recent report experienced problems of enough technical complexity to require frequent vendor representative assistance to repair and service the equipment (Radian, 1991).

Despite these technical concerns, this BACT analysis evaluates the potential cost effectiveness of SCR use.

4.3.1.2 Selective Noncatalytic Reduction

Nitrogen oxide emissions from other types of combustion sources also have been controlled through installation of selective noncatalytic reduction (SNCR) systems such as Thermal $DeNO_X$ and NO_XOUT. SNCR systems require gas temperatures of at least 1,500°F for NO_X reduction. Temperatures below 1,300°F result in ammonia slipping through the system unreacted without any corresponding reduction in NO_X emissions. The temperature, as reported earlier at the outlet of a CT unit utilizing dry low NO_X combustors, is too low (950°F to 1,100°F) for such a system. Accordingly, this alternative is judged not to be technically feasible for application on a CC unit.

4.3.1.3 Combustion Controls

Use of water or steam injection in the combustion zones of a CT unit can limit the amount of NO_x formed. Thermal NO_x formation is avoided due to lower combustion temperatures resulting from the water or steam injection. The degree of reduction in NO_x formation is somewhat proportional to the amount of water or steam injected into the turbine.

Since the CT unit NSPS for NO_x were last revised, CTs have improved their tolerance to the water or steam necessary to control the NO_x emissions below the current NSPS level. However, there is still a point at which the amount of water or steam injected into the turbine seriously degrades the turbine's reliability and operational life. With the manufacturers' existing turbine designs and standard combustors, this generally occurs below a NO_x emission level of about 25 ppmvd when firing natural gas and 42 ppmvd when firing fuel oil.

The advanced combustor designs available for the Polk County Site will be capable of achieving low NO_x emissions without the use of water or steam injection (dry) while firing natural gas. Considering the water use issues prevalent in Florida, dry low NO_x combustion controls are preferred. This analysis disregards further consideration of wet NO_x control CTs when natural gas is used.

As cited in recent General Electric Company (Black & Veatch, 1992) CT performance data, two generations of dry low NO_x combustors will be available for the Polk County Site. Other CT manufacturers have committed that their future technology will support lower NO_x emissions without water injection on natural gas. For clarity, this BACT is based upon GE data but will not preclude other potential vendors that are capable of meeting the data presented in this BACT discussion. The GE Dry Low NO_x II Combustor is capable of combustor-controlled NO_x emissions of 25 ppmvd while burning natural gas. Fuel oil burning requires water injection and has NO_x emissions of 42 ppmvd. The GE Dry Low NO_x III Combustor is capable of combustor-controlled NO_x emissions of 12 ppmvd while burning natural gas. Fuel oil burning (as a back-up fuel) has NO_x emissions of 42 ppmvd and requires water injection. Fuel oil burning will be limited to no more than 500 hours per year and is expected to have only a minor impact on water usage.

4.3.2 Summary of Technologies for Evaluation

The following control technologies are ranked according to their control effectiveness:

- Dry Low NO_X II Combustor with SCR designed to reduce NO_X emissions from 25 to 6 ppmvd while firing natural gas and from 42 to 15 ppmvd while firing fuel oil with water injection.
- Dry Low NO_X III Combustor with NO_X emissions of 12 ppmvd while firing natural gas and 42 ppmvd while firing fuel oil with water injection.

Table 4-2 lists the estimated NO_X emissions that would result from the two alternatives being considered. The annual emissions are based on 8,260 hours per year of full-load operation while firing natural gas and 500 hours per year of full-load operation while firing fuel oil. Annual emissions from a Dry Low NO_x II Combustor at the 25/42 ppmvd levels have been estimated at approximately 2,704 tons per year based on this operating scenario.

4.3.3 Evaluation of Feasible Technologies

The following evaluation considers energy, environmental, and economic impacts as a result of applying the previously mentioned technologies.

4.3.3.1 Energy Impacts Analysis

The use of an SCR system will require the use of additional energy. The SCR system requires energy to vaporize ammonia and energy to operate blowers or air compressors necessary to provide dilution air for injection of the additive. In addition, an SCR system will add approximately 4 inches water gauge (w.g.) gas pressure drop to the system as a result of the catalyst. This will reduce the output of the CC units by approximately 0.42 percent (4 MW). Since power demand will remain constant, this derate of electrical output will be replaced by a combustion source that likely has higher NO_X emissions than the units at the Polk County Site.

4.3.3.2 Environmental Impacts Analysis

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA).

Some ammonia slip (including a number of amine compounds) from the HRSG stack is unavoidable due to the imperfect distribution of the reactant and reaction inefficiencies associated with catalyst reactivity or operating temperatures. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. At least one air pollution control district in California recently set an ammonia emissions limit of 10 ppmvd. Unreacted ammonia emissions from an SCR system could average 5 to 10 ppmvd. However, excursions due to ammonia injection control problems could result in ammonia slips in excess of 40 ppmvd.

Monitoring ammonia slip emissions has also proven to be difficult. To date, there is not a reliable, accurate ammonia slip monitor available. Poor monitor system response and accuracy can make proper ammonia injection difficult. This can lead to excessive ammonia slip emissions.

Use of an SCR system will result in an increase of SO_3 emissions and a corresponding increase in sulfuric acid mist. These increases into an area already sensitive to crop damage resulting from both SO_3 and sulfuric acid mist emissions from the phosphate industry must be minimized. Use of an SCR system will unnecessarily increase SO_3 and sulfuric acid mist emissions.

Anhydrous ammonia is also a hazardous material. Accordingly, this material must be handled and stored with extreme care. There is a potential for ammonia to be released during transportation, transfer, and storage, resulting in additional emergency planning and training requirements.

The most common commercial SCR catalysts are vanadia/titania based, where vanadium pentoxide (V_2O_5) is used as the active catalyst compound. Vanadium is classified by the EPA as a hazardous material, and as such would require disposal in a RCRA hazardous waste (Subtitle C) landfill. Because of the requirements associated with such disposal, some manufacturers have stated they will accept the return of deactivated vanadia based catalyst which they manufactured. However, it is not certain whether or not this alternative will be available in the future when the quantity of spent catalyst requiring disposal becomes significant and the associated costs and liability for disposal are realized. This issue is further complicated by transportation of hazardous wastes through third-party states or internationally. Although existing federal laws prohibit states from outlawing such transportation, there continues to be a political and public concern regarding the transportation of hazardous wastes across state lines.

4.3.3.3 Economic Impacts Analysis

Table 4-3 presents estimated differential capital costs for installing four CC units using the two NO_X control technologies ranked previously. Table 4-4 presents estimated levelized annual costs for the four CC units using the different NO_X control technologies. The overall project economic criteria are presented in Table 4-1. The capital costs for the SCR systems include the costs for ammonia storage, ammonia injection, catalytic reactors, HRSG modifications, an ammonia emergency preparedness plan, and balance of plant equipment. Capital costs for the SCR systems were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the catalyst material were based on vanadium/titanium catalysts, as opposed to zeolite or platinum. This choice of material will keep the SCR system costs conservatively low.

In addition to the 1992 equipment supply costs, the total capital costs include a contingency margin, escalation, indirect costs, and allowance for funds used during construction (AFUDC). The following paragraphs detail how these costs are calculated.

The contingency margin of 20 percent accounts for uncertainties inherent in estimating material and labor costs during this early stage of conceptual design. Contingency is calculated by multiplying the 1992 capital cost listed on Table 4-3 by 20 percent.

The price quotations obtained for SCR systems are in 1992 dollars, essentially reflecting immediate delivery. The Polk County Site SCR equipment would not be paid for until delivery. Accordingly, prices would escalate to the anticipated delivery date. For the purposes of economic evaluation, the delivery date is estimated to occur at the midpoint of the project construction schedule. Therefore, direct capital costs plus contingency are escalated at the rate of five percent per year to the midpoint of construction. Construction and startup of the 940 MW CC units at the Polk County Site will occur over a four-year period. If the four 235 MW CC unit option is selected the first CC unit will begin commercial startup in November

1998, two more CC units will begin commercial startup in November 1999, and the final CC unit will start up in November 2000. Because some common plant equipment for the fourth CC unit will be purchased and installed during the early part of construction, and available power from commercial startup of the first unit will offset AFUDC costs for the later units, the midpoint of construction and commercial start-up dates of the middle two CC units is used for the economic analysis. The midpoint of construction is assumed to be in May 1998. Therefore, escalation costs are calculated by multiplying the 1992 capital cost plus contingency by a rate of five percent escalation compounded for six years. The addition of 1992 capital costs, contingency, and escalation results in a direct capital cost for the four CC units equipped with Dry Low NO_X II Combustors with SCRs and Dry Low NO_X III Combustors utilizing combustion controls of approximately $16.5 million and $7.7 million, respectively.

~4m SCR DLN III ~ 2 million

Indirect costs cover owner and engineer costs to design, procure, install, and start up the SCR system. It is estimated that these costs will be approximately 15 percent of the direct capital cost, or about $2.5 million and $1.2 million (1999 dollars) for the Dry Low NO_X II Combustor with SCR system and Dry Low NO_X III Combustors utilizing combustion controls, respectively.

Financing of projects such as the proposed project at the Polk County Site requires significant investment prior to completion. Financing of this investment is typically referred to as AFUDC. AFUDC is applied to the direct capital cost (escalated with contingency) plus indirect costs from the midpoint of construction until commercial startup. Commercial startup is assumed to be November 1999 for the purposes of this evaluation (an AFUDC duration of 1.5 years for SCR-related items). The AFUDC rate is estimated to be approximately 10 percent. Therefore, AFUDC is calculated by multiplying the direct capital cost plus indirect costs by a rate of 10 percent compounded for 1.5 years. The addition of direct capital costs, indirect costs, and AFUDC results in the 1999 total capital cost listed in Table 4-3.

The 1999 total differential capital cost for installation of four CC units utilizing the Dry Low NO_X II Combustors and SCR systems at the Polk County Site to achieve a 6 ppmvd NO_X emission rate is estimated to be $11,704,000.

Table 4-4 presents the levelized annual costs and emission rates (combustion controlled and post-combustion controlled) for four CC units using the NO_X emission control technologies being evaluated for the Polk County Site. Annual operating costs for SCR use include operating personnel, maintenance costs (primarily catalyst replacement), ammonia additive, energy, and replacement power from lost generating capacity.

Operating personnel costs are based on the addition of one person (one shift per day) to the staff of the plant to operate and maintain SCR equipment. The assumed 1992 operator cost is $53,660 per year including overheads and benefits.

Maintenance costs consist of routine SCR system maintenance plus the predominant expense of catalyst replacements. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers are willing to guarantee catalyst lives of three years. Therefore, the costs calculated in Table 4-4 assume a catalyst life of three years. Catalyst replacement costs are approximately 70 percent of the initial catalyst system cost, or approximately $3.5 million (1999 dollars).

Ammonia costs are calculated assuming a 1992 ammonia cost of $250 per ton. Ammonia consumption rates were calculated based on SCR manufacturer provided information regarding reaction stoichiometries. It is estimated that the ammonia consumption rate will be approximately 60 lb/hr per combustor for the Dry Low NO_X II Combustor CC units.

Energy consumption costs reflect the electrical consumption requirements of the SCR system as well as fuel input costs associated with the differences in system heat rates. Energy consumption costs are calculated based on a 1992 levelized energy cost of 62 mills/kWh. Fuel input cost (heat rate penalties) are calculated based on a levelized natural gas cost of $4.88/mmBtu and a levelized fuel oil cost of $9.39/mmBtu.

Due to the pressure drop associated with the use of an SCR system, the CC units will be derated by approximately 0.42 percent (4 MW). This lost generating capacity will reduce the amount of available power generated by the plant. Replacement power costs associated with this derate are based on a 1992 levelized energy revenue of 62 mills/kWh.

The 1992 operating cost estimates were escalated to the first year of operation (1999) based on an escalation rate of 5 percent. These first-year costs were also levelized to account for the effect of escalation and present worth discounting of future annual expenditures. Assuming a constant escalation rate of 5 percent, a constant present worth discount rate of 10.23 percent, and the 20-year life of the facility, the levelization factor is 1.42. Accordingly, first-year operating costs were multiplied by this levelization factor to determine the levelized annual operating costs listed in Table 4-4.

Total 1999 levelized annual costs for the NO_X control system are calculated as the sum of levelized annual operating costs and fixed charges on capital investment. Fixed charges are those annual ownership costs that vary directly with the capital investment. A fixed-charge rate of 16.35 percent was used to calculate the costs listed in Table 4-4. The fixed-charge rate was calculated based on project specific factors for cost of debt, depreciation, property taxes, and insurance margins.

The total incremental annual cost for installation and operation of SCR systems on four CC units using Dry Low NO_X II Combustors at the Polk County Site, using the Dry Low NO_X II Combustor CTs as a base, is estimated to be $8.1 million (November 1999 dollars). The SCR equipped units would be capable of meeting an NO_X emission limit of 6 ppmvd. This annual cost results in a cost effectiveness value (incremental NO_X emission reduction cost) of approximately $10,600 per ton based on the difference between four CC units using Dry Low NO_X II Combustors with SCRs and four CC units using Dry Low NO_X III Combustors with combustion-controlled NO_X emissions of 12 ppmvd.

4.3.4 Rationale for Proposed NO_X BACT

CC units using advanced design Dry Low NO_X III Combustors to control NO_X emissions to 12 ppmvd represents BACT for the Polk County Site. Installation of the CC units using Dry Low NO_X II Combustors with SCR systems designed to meet a most stringent control technology NO_X emission limit of 6 ppm (approximately 76 percent reduction) would add approximately $11.7 million to the capital cost of the project. Addition of the Dry Low NO_X II Combustor CC units with SCR systems increases total levelized annual costs for the project by approximately $8.1 million above the costs of the Dry Low NO_X III Combustor CC units, resulting in a cost effectiveness value (incremental NO_X emission reduction cost) of approximately $10,600 per ton.

The use of an SCR system could also result in adverse environmental effects due to unreacted ammonia being released to the atmosphere or accidental release of ammonia during transport or storage causing a potential human health hazard. Although an SCR system would allow NO_X emissions to be reduced by 6 ppmvd, ammonia emissions could be as high as 10 ppmvd due to ammonia slip. Use of an SCR system will also require frequent transfers of ammonia increasing the risk of accident and exposure. An SCR system would trade the potential for small decreases in ambient NO_X concentrations for potential health and safety problems due to ammonia exposure.

The NO_x emissions from the proposed CC units equipped with Dry Low NO_x III Combustors are lower than recent permit decisions for similar CC projects in the state of Florida. The lowest NO_x emission limit listed in the EPA's clearinghouse documents for the state of Florida is 42 ppmvd. However, several sites within the state have recently been permitted for NO_x emissions of 25 ppmvd (natural gas) and one project has proposed 15 ppmvd.

Based on the foregoing site-specific technical, economic, energy, and environmental considerations, use of Dry Low NO_x III Combustor advanced design CC units to achieve NO_x emissions of 12 ppmvd while burning natural gas represent BACT for the Polk County Site.

4.4 SULFUR DIOXIDE EMISSIONS

The NSPS established by EPA for emissions from CTs sets a maximum SO_2 level in the flue gas of 150 ppmvd or a maximum fuel sulfur content of 0.8 percent by weight (40 CFR 60, Subpart GG).

Typically, natural gas has only a trace of sulfur (2,000 grains per million standard cubic feet or less) and no supplemental SO_2 emission controls have been imposed on natural gas-fired CC units. The CC units at the Polk County Site will burn fuel oil for a maximum of 500 hours per year and then only as a back-up fuel. Recent permits for fuel oil-fired CTs have included limits on maximum allowable fuel sulfur contents. The use of low sulfur fuel oil (maximum of 0.05 percent sulfur by weight) as a back-up fuel for natural gas would impose no significant differential capital costs on the project. The resulting SO_2 while buring oil emissions are estimated at approximately 9 ppmvd corrected to 15 percent oxygen.

Current BACT/LAER clearinghouse documents (EPA, 1990) do not list any natural gas- or fuel oil-fired CC units that are required to use flue gas desulfurization (FGD) systems to meet SO_2 emission requirements. The high pressure drops across FGD systems make them technically infeasible for application on CC units. Also, addition of an FGD system would be an excessive method of SO_2 emission control, because SO_2 emissions will be low even without an FGD system. The significant capital and operating costs associated with FGD systems would likely seriously impact the economic feasibility of the project.

Based on economic, energy, and environmental considerations, firing natural gas as the primary fuel, and limiting the amount of time low sulfur fuel oil operation will be allowed (500 hours per year) is proposed as BACT for SO_2 emissions for the Polk County Site.

4.5 CARBON MONOXIDE EMISSIONS

CTs have inherently low carbon monoxide (CO) emissions. CO is formed by incomplete combustion of fossil fuels. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO emissions. CO formation also varies depending on the manufacturer's combustor design. The GE CO emissions used in this analysis are conservatively high when compared to similar sized units offered by other CT manufacturers.

A review of control technology determinations (CARB, 1991 and 1992; EPA 1985 and 1990) indicates that the lowest CO emission limit established to date for a CC unit is 2.0 ppmvd for a CC unit located in a California CO nonattainment area. That permit value was based on the use of an oxidation catalyst system. Based on this determination, the most stringent control technology for CO emissions is good combustion control and use of an oxidation catalyst system. The Polk County Site in not classified as a CO nonattainment zone; therefore, application of the most stringent control technology is not mandatory for CO emissions compliance.

The CO oxidation catalyst process is based on a straight catalytic reaction requiring no additives. The reactions and catalysts used (platinum based) are similar to the catalytic oxidation technology used for automotive emission control. Products from the reaction include carbon dioxide and water. Catalytic oxidation systems are capable of CO reductions of between 50 and 80 percent. However, this reduction potential will be somewhat influenced by initial concentrations of the pollutants.

4.5.1 <u>Summary of Technologies for Evaluation</u>

The following control technologies are ranked according to their control effectiveness:

- Oxidation catalyst to reduce CO emissions by approximately 80 percent, and
- Combustion control to assure proper fuel mixing and complete fuel combustion.

4.5.2 <u>Evaluation of Feasible Technologies</u>

The following evaluation considers energy, environmental, and economic impacts as a result of applying the previously mentioned technologies.

4.5.2.1 Energy Impacts Analysis

Similar to the SCR system, use of a CO catalyst would result in a derate of approximately 0.42 percent (4 MW) of CT output. Since power demand will remain constant, this derate will be replaced by a combustion source that has higher CO emissions than the planned units at the Polk County Site.

4.5.2.2 Environmental Impacts Analysis

A catalyst which oxidizes CO to CO_2 will also oxidize SO_2 to SO_3. While firing fuel oil, 50 to 60 percent of the SO_2 in the flue gas will be converted to SO_3. When the SO_3 comes in contact with moisture, it will form sulfuric acid mist which can cause corrosion damage to downstream plant equipment and damage to surrounding vegetation when found in high enough concentrations. The sulfuric acid mist created will also increase particulate emissions from the facility.

Although CO has been well documented as a hazardous pollutant, significant international pressure is now being exerted to reduce CO_2 emission levels in response to the suspected contributions of the gas to global warming. A CO oxidation catalyst could increase the CO_2 emissions from the facility by almost 380 pounds per hour (1,660 TPY assuming 8,760 hours per year of operation).

4.5.2.3 Economic Impacts Analysis

Table 4-5 presents the capital and levelized annual costs of installing a CO catalytic emission reduction system on CC units equipped with four Dry Low NO_X III Combustors. The capital costs for the catalytic reduction system include the costs of the catalytic reactors and balance of plant equipment. Capital costs for the catalytic emission reduction system are based on budgetary quotations from equipment manufacturers. Annual operating costs include maintenance (predominantly catalyst replacement) and lost generation due to the pressure drop across the catalyst. The calculations of capital and levelized annual costs are similar to the methods described for an SCR system in Section 4.3.

The total capital cost for installation of a CO emission reduction system at the Polk County Site is approximately $12.3 million (November 1999 dollars). The total annual cost for installation of a CO emission reduction system at the Polk County Site would be approximately $6.6 million (November 1999 dollars). These costs are based on a 100 percent capacity factor.

Table 4-5 lists the cost effectiveness (incremental reduction cost) for use of an oxidation catalyst. The emission reduction systems would be capable of meeting the indicated CO emission limits. In general, CO reductions were limited to 80 percent reduction (the practical limit of the technology). Compliance with the most stringent control technology emission requirements would result in a cost effectiveness value (incremental emission reduction cost) of approximately $6,400 per ton. This cost effectiveness value is conservatively low due to the 100 percent capacity factor assumption.

4.5.3 Rationale for Proposed CO BACT

Installation of a CO catalyst control system designed to meet a CO emission limit of 5 ppmvd would add approximately $12.3 million to the capital cost of the project. The total levelized annual costs for the project would increase by $6.6 million resulting in an incremental removal cost of approximately $6,400 per ton of CO removed.

Based on energy, environmental, and economic considerations, the use of combustion control to limit CO emissions to a maximum of 25 ppmvd while firing natural gas and 30 ppmvd while firing fuel oil represents BACT for the Polk County Site.

4.6 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

CTs have inherently low volatile organic compound (VOC) emissions (expressed as nonmethane hydrocarbons). VOCs, like carbon monoxide, are formed by incomplete combustion of the fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize VOC emissions. VOC formation is limited by ensuring complete, efficient combustion of the fuel in the CT.

A review of control technology determinations (CARB, 1991 and 1992; EPA, 1985 and 1990) indicates that the lowest VOC emission limit established to date for a CC unit is 4.1 ppmvd for a unit located in Rhode Island which is an ozone nonattainment area. This facility will use combustion controls to limit VOC emissions. Based on this determination, the most stringent control technology for VOC emissions is good combustion control. Accordingly, combustion control is proposed as BACT for VOCs at the Polk County Site. The expected VOC emission level is 6 ppmvw.

4.7 PARTICULATE MATTER (PM_{10}) EMISSIONS

The natural gas fuel to be used in the proposed CC units will contain only trace quantities of noncombustible material and the fuel oil use will be limited to 500 hours per year. Therefore, emission of particulate matter from the facility will be controlled by filtering the turbine inlet air and ensuring as complete combustion of the fuel as possible. The NSPS for CC units do not establish an emission limit for particulate matter. A review of BACT/LAER clearinghouse documents did not reveal any post-combustion particulate matter control technologies being used on CC units. The manufacturer's standard operating procedures will ensure as complete combustion of the fuel as possible. Particulate emissions from each CC unit will be 9 lb/hr and 17 lb/hr for natural gas and fuel oil firing, respectively. Accordingly, combustion control is proposed as BACT for particulate matter and PM_{10}.

4.8 BERYLLIUM EMISSIONS

The emissions of beryllium from the facility will be determined by the beryllium content of the fuel. Natural gas has no measurable beryllium content and the annual beryllium emissions when firing natural gas are predicted to be negligible. The proposed fuel oil typically contains a trace amount of beryllium, on the order of 2.5×10^{-6} pounds per million Btu (lbs/mmBtu). A review of BACT/LAER clearinghouse documents did not reveal any CC unit project which has been required to install supplemental pollution control equipment to reduce beryllium emissions. Therefore, the use of natural gas and limited firing of fuel oil, combined with good combustion techniques, represents BACT for controlling beryllium emissions from the CC units.

4.9 SULFURIC ACID MIST EMISSIONS

Sulfuric acid mist (H_2SO_4) emissions will be present whenever fuels containing sulfur are burned in the CC units. During combustion a majority of the sulfur contained in the fuel is oxidized to SO_2. However, a small portion of the sulfur (conservatively assumed to be 7 percent) further oxidizes to SO_3. Sulfur trioxide further hydrates at temperatures below 325°F to sulfuric acid.

A review of BACT/LAER clearinghouse documents did not reveal any post-combustion sulfuric acid mist control technologies being used on CC units. Post combustion control technologies such as flue gas desulfurization (FGD) system could be used to reduce H_2SO_4 emissions. However addition of an FGD system would be an excessive method of emission control since H_2SO_4 emissions will be low even without post combustion control systems. The H_2SO_4 emissions are conservatively estimated to be 9.0 lb/hr and 0.099 lb/hr per unit while burning fuel oil and natural gas respectively. The significant capital and operating costs associated with FGD systems could seriously impact the economic feasibility of the project. As with FGD systems for SO_2 control, the high pressure drops across the systems makes them technically infeasible for application on CC units.

Based on economic, energy, and environmental considerations, firing natural gas as the primary fuel, and limiting the amount of time low sulfur fuel oil (0.05 percent sulfur) operation will be allowed (500 hours per year) is proposed as BACT for H_2SO_4 emissions for the Polk County Site.

4.10 OTHER EMISSIONS

Table 4-6 presents uncontrolled emission estimates for other regulated (mercury and lead) and hazardous pollutants when burning fuel oil. These pollutants are either contained in the fuel oil ash or dissolved in the liquid oil. Natural gas contains essentially no ash. Therefore, with the exception of benzene and formaldehyde, natural gas does not contain these trace pollutants. The only identified methods of controlling the emission of these pollutants from CC units are complete combustion of the fuel and the inherent quality of the fuel. Accordingly, combustion control is proposed as BACT for the listed pollutants. This will be consistent with the recommended BACT determinations for CO and VOC emission control.

4.11 SUMMARY

Table 4-7 summarizes the control technologies that are proposed as BACT for the initial phase of the Polk County Site (940 MW of CC units) for the pollutants subject to PSD review.

4.12 AUXILIARY BOILER — BACT

A 99 mmBtu/hr (heat input) natural gas or fuel oil fired auxiliary boiler will be used to preheat the HRSGs and steam turbines during cold startup. The auxiliary boiler will be used only if all four CC units are shut down. Once one CC unit is operational, and steam from the operating unit's HRSG is used to preheat the other units, the auxiliary boiler will be shut down. Each CC unit will exceed emission standards for approximately three hours each time the unit is started from a cold condition. The use of the auxiliary boiler will reduce the magnitude and duration the unit does not meet emission standards. This is expected to occur up to ten times per year under normal operating conditions and more often under abnormal conditions such as initial plant checkout, startup, and testing. Auxiliary boiler operation will be limited to 100 hours per year, and will be fired on either natural gas or fuel oil.

4.12.1 Nitrogen Oxides Emissions

The NSPS governing air emissions from the auxiliary boiler are contained in 40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units). Additionally, BACT/LAER Clearinghouse documents (EPA, 1985 and 1990) listed the most stringent NO_x controls for a boiler in this class as low NO_x burners and other combustion controls for a source in Michigan. No NSPS criteria have been established regarding NO_x emissions for an auxiliary boiler. The auxiliary boiler is expected to have NO_x emissions of 9.9 lb/hr and 19.8 lb/hr while firing natural gas and fuel oil, respectively. These emission rates will be achieved using low NO_x burners and combustion controls.

The low NO_x burners on the auxiliary boiler will operate in a manner similar to the low NO_x burners on the CC units. The basic concept of low NO_x burners is a two-stage combustion process. During the first stage, conversion to NO_x of fuel-bound nitrogen is controlled by forcing the fuel nitrogen compounds into the gas phase using a fuel rich condition. Under this condition, there is a deficiency of oxygen and the intermediate nitrogen compounds decay at a maximum rate into molecular nitrogen. The remaining combustion air is admitted in the second stage. This slow burning rate reduces flame temperature, thereby limiting the amount of thermal NO_x formed during latter stages of combustion.

Flue gas recirculation is another method of controlling NO_x formation. Flue gas recirculation has historically been used to control steam temperature. Flue gas is taken from the economizer outlet and reintroduced into the wind box of the burner utilizing a fan and ductwork. The recirculation of flue gas to the furnace area lowers the flame temperature and increases the flue gas mass flow. The lowered flame temperature leads to reduced furnace heat absorption and a slightly increased flue gas temperature. This increased flue gas temperature and gas flow increases the steam temperature in the convection pass. However, the lowered flame temperature reduces thermal NO_x formation in the furnace.

NO_x emissions from the auxiliary boiler can also be limited using post-combustion control technologies. Both SCR and SNCR systems can be used on auxiliary boilers. NO_x emission reduction efficiencies using SCR and SNCR systems on an auxiliary boiler such as the one at the Polk County Site would be approximately 70 percent and 40 percent, respectively. As previously discussed in the CC unit NO_x control section, SCR and SNCR systems reduce NO_x emissions by introducing an ammonia reagent into the flue gas to react with the NO_x particles. Both processes selectively reduce NO_x into nitrogen and water vapor by reaction with the ammonia. The distinction between the two technologies is that the SCR systems require the use of a catalyst to initiate the reaction, while SNCR systems rely on the appropriate ammonia injector location and temperature to achieve NO_x reduction. SNCR systems use almost four times the amount of ammonia that an SCR system uses per ton of NO_x removed.

Both the SCR and SNCR processes are temperature sensitive. The optimum flue gas temperature ranges for SCR and SNCR operation are approximately 650°F to 750°F and 1,550°F to 1,900°F, respectively. Both of these temperature ranges occur in the convective or backpass portion of the boiler. Since auxiliary boilers are typically packaged designs, the boiler manufacturer would be required to alter the standard design to accommodate post-combustion NO_x control systems. For SCR systems, the boiler backpass could be shortened to provide a flue gas exit temperature in the required range. This would reduce the boiler thermal efficiency due to reduced heat transfer surface area in the boiler backpass. An economizer could be added after the SCR catalyst to recover a portion of this lost thermal efficiency. For SNCR systems, operation below the optimum temperature window will result in excessive ammonia emissions (slip) with no corresponding reduction in NO_x emissions. Operation above the optimum temperature window will result in increased NO_x emissions. The exact location of this temperature range will occur at different locations within the boiler, dependent on boiler load and inlet air temperatures. Therefore, multiple sets of injection nozzles would be required in order to follow the optimum temperature location.

Post-combustion NO_x control systems will require additional power for ammonia vaporization and injection. In addition, fan power will be required on an SCR system in order to overcome draft loss due to the catalyst. Both systems also use ammonia. As discussed in the CC unit NO_x emissions control section, ammonia is listed as a hazardous substance under SARA Title III and must be handled with caution. Also, since the auxiliary boiler will only be operated for 100 hours per year, the total NO_x emissions reduced will be small. It is estimated that the total annual NO_x emissions reduced using SCR and SNCR systems on the auxiliary boiler while firing natural gas will be 0.35 tons and 0.20 tons, respectively. Clearly, the incremental cost effectiveness of post-combustion NO_x emission control systems on the auxiliary boiler (dollars per ton of NO_x removed) will be extremely high for this project. Therefore, based on energy, environmental, and economic considerations, low NO_x burners and combustion controls are proposed as BACT for NO_x emissions control on the auxiliary boiler.

4.12.2 Sulfur Dioxide and Sulfuric Acid Mist Emissions

Subpart Dc of the NSPS limits SO_2 emissions to 0.5 lb/mmBtu for oil fired sources. BACT/LAER Clearinghouse documents (CARB, 1991 and 1992; EPA, 1985 and 1990) list the most stringent SO_2 determination for this source category as 0.05 lb/mmBtu for a proposed project in a California nonattainment area. This facility burns residual fuel oil with a sulfur content of approximately 1.0 percent. Caustic scrubbers will be used at this facility to remove 95 percent of the SO_2.

Emissions of SO_2 can be controlled by either limiting the sulfur content of the fuel, or by a post combustion control system. Since the unit will only operate for up to 100 hours per year, the addition of an FGD system to control emissions would be an excessive method of SO_2 control. The FGD system would require additional energy in order to overcome the draft loss due to the FGD system and for reagent and waste handling. The significant capital and operating costs associated with FGD systems could seriously impact the economic feasibility of installing an auxiliary boiler.

Sulfuric acid mist (H_2SO_4) emissions will be present only when fuels containing sulfur are being burned in the auxiliary boiler. During combustion a majority of the sulfur contained in the fuel is oxidized to SO_2. However, a small portion of the sulfur (approximately one percent) further oxidizes to SO_3. SO_3 further hydrates at temperatures below 325°F to (H_2SO_4). Emission controls for (H_2SO_4) are the same as those used for SO_2. The fuel oil used at the Polk County Site will be low sulfur fuel oil (0.05 percent). SO_2 and sulfuric acid mist emissions while burning natural gas are estimated at 0.0641 lbs/hr and 0.00099 lbs/hr, respectively. SO_2 and sulfuric acid mist emissions while burning low sulfur fuel oil are estimated at 5.27 lbs/hr and 0.082 lbs/hr, respectively.

Based on economic, energy, and environmental considerations, use of natural gas and low sulfur fuel oil and limited unit operation is proposed as BACT for SO_2 and sulfuric acid mist emissions control on the auxiliary boiler.

4.12.3 Carbon Monoxide and Volatile Organic Compound Emissions

Subpart Dc of the NSPS does not list any requirements for CO or VOC emissions for auxiliary boilers. Additionally, BACT/LAER Clearinghouse documents (CARB, 1991 and 1992; EPA, 1985 and 1990) do not list any CO or VOC emissions limits for Subpart Dc classification sources.

CO and VOCs are formed as a result of incomplete combustion of the fuel. As noted in the CC unit evaluation of CO emissions control, the control determination for NO_x must be taken into consideration when evaluating CO and VOC controls since NO_x formation is reduced by incomplete combustion. CO and VOC emissions are estimated to be 4.9 lb/hr and 0.50 lb/hr, respectively, while firing natural gas using low NO_x burners and combustion controls.

Catalytic oxidation is a post-combustion method for controlling CO and VOC emissions. The process oxidizes CO to CO_2 and VOC hydrocarbons to CO_2 and H_2O using a catalyst. CO control catalysts utilize a precious metal based catalyst. None of the catalyst components are considered toxic.

The optimum flue gas temperature range for CO and VOC catalyst operation is between 850°F and 1,100°F. Flue gas from the auxiliary boilers will typically be between 475°F to 620°F in the areas of the auxiliary boilers in which the catalyst can be located. Therefore, a CO and VOC catalyst is not technically feasible for use on the auxiliary boilers. Good combustion controls, therefore, represent BACT for CO and VOC emissions.

4.12.4 Particulate Matter (PM_{10}) Emissions

NSPS limits oil fired steam generating units with heat input capacities of 30 mmBtu/hr or greater to an opacity limit of 20 percent. NSPS has no mass emission limits for particulate. BACT/LAER Clearinghouse documents (CARB, 1991 and 1992; EPA, 1985 and 1990) do not list any particulate emission limitations or control equipment requirements for Subpart Dc classification boilers that burn natural gas or distillate fuel oil.

The natural gas fuel to be used in the proposed auxiliary boiler will contain only trace quantities of noncombustible material and fuel oil use will be limited. Also, the auxiliary boiler will only be used for up to 100 hours per year. The emission of particulates from the auxiliary boiler can be controlled by ensuring as complete combustion of the fuel as possible. The use of a post-combustion particulate control device would be excessively expensive. Estimated particulate emissions from the auxiliary boiler will be 0.50 lb/hr and 4.9 lb/hr for natural gas and fuel oil firing, respectively. Accordingly, combustion control is proposed as BACT for particulate matter and PM_{10}.

4.12.5 Trace Pollutant Emissions

An additional requirement of BACT analyses is the evaluation of control technologies for lead, PSD noncriteria pollutants, and other hazardous air pollutants that may occur.

Trace pollutants are either contained in the fuel ash or, for fuel oil, dissolved in the liquid oil. Natural gas contains essentially no ash. Therefore, with the exception of benzene and formaldehyde, natural gas does not contain hazardous trace pollutants. Typically, trace pollutants in the fuel will either volatilize upon combustion or be carried as solid particles with the fine particulate (PM_{10}). If temperature and pressure conditions are suitable, the volatilized pollutants will condense onto the fine particulate in the flue gas. Therefore, the only feasible methods of controlling the emission of these trace pollutants is using the same technology used for controlling PM_{10} emissions. Accordingly, combustion control is proposed as BACT for trace pollutant emissions.

4.12.6 Summary

Table 4-8 summarizes the control technologies that are proposed as BACT for purposes of PSD pollutants and FDER steam generator regulations for the auxiliary boiler.

TABLE 4-1
PROJECT ECONOMIC EVALUATION CRITERIA

Economic Parameters	Value
Contingency (percent)	20
Indirects (percent)	15
Escalation (percent)	5
Present Worth Discount Rate (percent)	10.23
Allowance for Funds Used During Construction (AFUDC) (percent)	10.23
Fixed Charges on Capital (percent)	16.35
Economic Life (years)	20
Capacity Factor (percent)	100
Levelization Factor	1.42
1992 Ammonia ($/ton)	250
1992 Labor ($/year)	53,660
1992 Levelized Natural Gas Cost ($/mmBtu)	4.88
1992 Levelized No. 2 Fuel Oil Cost ($/mmBtu)	9.39
1992 Levelized Energy Cost (mills/kWh)	62.01
1992 Levelized Annual Demand ($/kW)	77.04
Net Generation (MW)	940
Commercial Operation (Startup)	November 1998 - November 2000
Primary Fuel	Natural Gas
Back-up Fuel	Fuel Oil
Catalyst Life (years)	3

Source: Black & Veatch, 1992

TABLE 4-2
ESTIMATED NO_X EMISSIONS FOR ALTERNATE COMBINED CYCLE CONTROLS

Control Alternative	Combustor-Controlled Emission NG/FO (ppmvd)	NO_x Removal Efficiency (percent)	Emission Rate NG/FO (ppmvd)	Annual NO_x Emission (tpy)
Dry Low NO_x II Combustor with SCR and water injection on fuel oil	25/42	76/64	6/15	681
Dry Low NO_x III Combustor with water injection on fuel oil	12/42	N/A	12/42	1,446

Notes:
1. Emission rates are corrected to 15 percent O_2.
2. Annual emission rates are based on four GE Frame 7FA CT units operating 8,260 hours per year while firing natural gas and 500 hours per year while firing fuel oil.
3. Values based on 72°F and 80% relative humidity.

Source: Black & Veatch, 1992

TABLE 4-3
SELECTIVE CATALYTIC NO_x REDUCTION SYSTEM CAPITAL COSTS

	Low NO_x II Combustor with SCR (6/15 ppm)	Low NO_x III Combustor (12/42 ppm)
• Combustion Turbine	Base	4,800
• SCR System	9,781	N/A
• Balance of Plant	486	N/A
1992 Capital Cost	10,267	4,800
• Contingency (20 percent)	2,053	960
• Escalation (5 percent/yr)	4,196	1,962
Direct Capital Cost	16,516	7,722
• Indirect Costs (15 percent)	2,477	1,158
• AFUDC (10.23 percent)	2,988	1,397
1999 Total Capital Cost	21,981	10,277
1999 Differential Capital Cost	11,704	Base

Notes:
1. Costs are based on four GE Frame 7FA CTs with HRSGs.
2. Costs are expressed in thousands of dollars (i.e., x $1,000).

Source: Black & Veatch, 1992

TABLE 4-4
LEVELIZED ANNUAL COSTS AND EMISSION RATES FOR NO_x REDUCTION

	Low NO_x II Combustor with SCR (6/15 ppm)	**Low NO_x III Combustor (12/42 ppm)**
• Differential O&M	3,547	Base
• Ammonia	494	Base
• Differential Fuel	Base	46
• Differential Power Consumption	217	Base
• Differential Generation	1,973	Base
1999 Annual Operating Cost	6,231	46
• Fixed Charges on Capital (16.35 percent)	3,594	1,680
1999 Total Levelized Annual Cost	9,825	1,726
• NO_x Emission Rates		
Combustion Controlled		
- ppmvd (NG/FO)	25/42	12/42
- tpy	2,704	1,446
Post-combustion Controlled		
- ppmvd (NG/FO)	6/15	N/A
- tpy	681	N/A
• Differential NO_x Reduction (tpy)	765	Base
• Cost Effectiveness ($/ton reduced)	10,587	Base

Notes:
1. Based on four GE Frame 7FA CTs with HRSGs operating 8,760 hours per year at 72°F and 80 percent relative humidity.
2. Costs and emission rates assume 8,260 hours of operation while firing natural gas and 500 hours of operation while firing fuel oil.
3. All costs, with the exception of cost effectiveness, are expressed in thousands of dollars (i.e., x $1,000).
4. Cost effectiveness expressed in dollars per ton of NO_x removed.

Source: Black & Veatch, 1992

TABLE 4-5
CO CATALYTIC OXIDATION SYSTEM CAPITAL AND LEVELIZED ANNUAL COSTS

	Capital and Levelized Annual Costs
Capital Costs	
• Oxidation Reactors	5,151
• Balance of Plant	612
1992 Capital Cost	5,762
• Contingency (20 percent)	1,152
• Escalation (5 percent)	2,355
Direct Capital Cost	9,269
• Indirect Costs	1,390
• Interest During Construction	1,677
1999 Total Capital Cost	12,336
• Levelized Annual Costs	
- Operation and Maintenance	3,242
- Lost Generation	1,355
- Fixed Charges on Capital (16.35 percent)	2,017
1999 Total Annual Cost	6,614
• Emission Rates (corrected)	
- Uncontrolled	
CO ppm (NG/FO)	25/30
tpy	1,295
- Controlled	
CO ppm (NG/FO)	5/6
tpy	259
Cost Effectiveness ($/ton)	6,384

Notes:
1. Based on four GE Frame 7FA CTs operating 8,760 hours per year at 72°F and 80 percent relative humidity.
2. Costs and emission rates assume 8,260 hours of operation while firing natural gas and 500 hours of operation while firing fuel oil.
3. All costs, with the exception of cost effectiveness, are expressed in thousands of dollars (i.e., x $1,000).
4. Cost effectiveness expressed in dollars per ton of CO reduced.

Source: Black & Veatch, 1992

TABLE 4-6
OTHER REGULATED AND HAZARDOUS POLLUTANT EMISSIONS
(940 MW - CC UNITS)

Pollutant	Emission Rate[1] (lb/mmBtu)	Annual Emission[2] (tpy)
• Antimony	0.0000221	0.0398
• Arsenic	0.0000042	0.00756
• Barium	0.0000195	0.0351
• Beryllium	0.0000025	0.00450
• Boron	0.0000651	0.117
• Cadmium	0.0000105	0.0189
• Calcium	0.000747	1.34
• Chromium	0.000048	0.0854
• Cobalt	0.00000906	0.0163
• Copper	0.00028	0.504
• Lead	0.0000089	0.0160
• Magnesium	0.000232	0.418
• Manganese	0.000014	0.0252
• Mercury	0.000003	0.00540
• Nickel	0.00017	0.306
• Selenium	0.00000235	0.00423
• Vanadium	0.0000696	0.125
• Zinc	0.000683	1.23
Volatile Organic Compounds		
• Benzene	0.000065	1.79
• Formaldehyde	0.00022	6.06

Notes:

1. Emission rates are for four CC units fired on fuel oil only, except for benzene and formaldehyde, which are for natural gas only.
2. Annual emissions are based on four CC units operating for 500 hours per year firing fuel oil at 40°F and 70 percent relative humidity, except for benzene and formaldehyde, which are based on 8,760 hours per year of natural gas firing.

Source: EPA, 1988

TABLE 4-7
SUMMARY OF BACT ANALYSIS RESULTS (CC UNITS)

Pollutant	Emission Rate (lbs/hr) (NG/FO)	Control Technology
CO	73/89	Good combustion control and limited annual fuel oil operation (25/30 ppmvd)
NO_x	70/291	Advanced design combustion control and limited annual fuel oil operation (12/42 ppmvd)
SO_2	0.951/90	Low fuel oil sulfur content (0.05 percent) and limited annual fuel oil operation
PM/PM_{10}	9/17	Good combustion control and limited annual fuel oil operation
VOC	10.4/11.2	Good combustion control (6/6 ppmvd)
Beryllium	Negligible/0.0041	Good combustion control and limited annual fuel oil operation
Sulfuric Acid Mist	0.0995/9	Low fuel oil sulfur content (0.05 percent) and limited annual fuel oil operation
Benzene	0.0987/Negligible	Good combustion control

Note: Emission rates based on a single GE Frame 7FA CT operating at 72°F and 80 percent relative humidity.

Source: Black & Veatch, 1992

TABLE 4-8
SUMMARY OF BACT ANALYSIS RESULTS (AUXILIARY BOILER)

Pollutant	Emission Rate (lbs/hr) (NG/FO)(1)	Control Technology
CO	4.9/4.9	Good combustion control
NO_x	9.9/19.8	Low NO_x burners; good combustion control; and limited annual fuel oil operation
SO_2	0.0641/5.27	Low fuel oil sulfur content (0.05 percent) and limited annual fuel oil operation
PM/PM_{10}	0.5/4.9	Good combustion control and limited annual fuel oil operation
VOC	0.5/0.99	Good combustion control and limited annual fuel oil operation
Beryllium	Negligible/0.00025	Good combustion control and limited annual fuel oil operation
Sulfuric Acid Mist(2)	0.00099/0.082	Good combustion control and limited annual fuel oil operation
Benzene	0.0067/Negligible	Good combustion control and limited annual fuel oil operation

Note: (1) Emission rates based on 99mm Btu/hr heat input rate for an auxiliary boiler.
(2) Estimating one percent of SO_2 to H_2SO_4 conversion for natural gas.

Source: Black & Veatch, 1992

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORING APPLICABILITY

Guidance from U.S. EPA (1987) was used to determine acceptable monitoring locations, parameters to be monitored, and monitoring methods. Based on the worst-case proposed source emissions data and preliminary air quality modelling results for the existing and proposed sources, it was determined that the following parameters would be monitored for the following reasons:

- SO_2 (Predicted impacts based on preliminary modelling were above the significant monitoring concentrations [13 $\mu g/m^3$, 24-hr average]);
- PM_{10} (Predicted particulate impacts based on preliminary modelling were close to the significant monitoring concentrations [10 $\mu g/m^3$, 24-hr average]);
- O_3 (VOC emissions were estimated to exceed 100 tons/year);
- Wind Speed; and
- Wind Direction.

A visit to the Polk County Site was made to select air quality/meteorological monitoring site locations based on the results of the preliminary air quality modelling assessment. Based on the results of the site visit, a monitoring site location to the northeast of the proposed plant site was selected which satisfied EPA siting criteria for each parameter to be monitored, as well as security, telephone service, and power availability needs. The monitoring site location is shown on Figure 5-1. Standard EPA monitoring methods and approved equipment are used at the monitoring site.

On-site monitoring data collection began officially on October 15, 1991, and will continue for one full year. FDER approved the use of four months of air quality and meteorological monitoring data in the SCA with the remaining eight months of data to be provided in a supplement to the SCA (Linn, 1991).

5.2 EXISTING REPRESENTATIVE AIR QUALITY MONITORING DATA

Some FDER ambient air monitoring data are available which can be used to characterize the existing conditions in the vicinity of the site. A map depicting the locations of the existing ambient air quality monitoring sites is presented as Figure 5-2. The FDER data from these monitors for 1990 are summarized in Table 5-1. FDER collected ambient total suspended particulate (TSP) data during 1990 at several locations in the vicinity. However, the TSP standards have now been replaced with standards for particulate matter less than or equal to 10 micrometers aerodynamic diameter (PM_{10}). The nearest FDER PM_{10} data are from the Tampa metropolitan area and are not very representative of Polk County. However, the TSP data for Polk County indicate that existing PM_{10} concentrations are also well below NAAQS/FAAQS.

Concentrations of SO_2 have been measured by FDER at Lakeland and Nichols. FDER data from 1990 show existing SO_2 concentrations at those nearby locations to be well below the AAQS.

Ambient data for NO_2, CO, O_3, and Pb have been collected by FDER only in the Tampa, St. Petersburg, and Sarasota metropolitan areas. Given the rural nature of the site, existing concentrations of these pollutants, which are usually associated with urban environments, should be well below the applicable standards.

A one-year monitoring program was conducted recently by Tampa Electric Company at two sites in western Polk County, approximately 12 miles to the southwest of the FPC Polk County Site monitoring location. A summary of data available from FDER for these stations, which operated from April 1, 1991, through March 31, 1992, is presented in Table 5-2.

5.3 POLK COUNTY SITE AIR QUALITY AND METEOROLOGICAL MONITORING PROGRAM

5.3.1 Monitoring Program Description

The FPC monitoring site selected is located south of Homeland and west of Highway 17. The location is approximately 100 feet south and 300 feet east of the southern end of paving on Old Fort Meade Road in an open field at an elevation of approximately 150 feet (MSL). Approximate UTM coordinates for the monitoring site are 418.70 km east and 3,076.35 km north (UTM Zone 17). EPA siting criteria for pollutants of interest are satisfied by the use of this location. A monitoring plan (FPC, 1991) was submitted to and approved by FDER.

The SO_2 analyzer is a Monitor Labs Model 8850 fluorescent method analyzer with an EPA equivalence designation number EQSA-0779-039. This analyzer is calibrated using an Environics Model 100 calibrator. The O_3 analyzer is a Dasibi 1003-Ah UV photometry analyzer with an EPA equivalence designation number EQOA 05-77-019, which is calibrated using a Dasibi 1008-PC transfer standard calibrator. The PM_{10} samplers used are General Metal Works Model GUV-15H with a reference designation number RFPS 12870063. The PM_{10} samplers are operated every six days in accordance with the FDER schedule. Data from the continuous analyzers are recorded on strip chart recorders, and hourly averages are calculated by an ESC 8000 AQM data logger.

The meteorological tower is a 10-meter Climatronics triangular tower with a Climatronics F460 wind measuring system consisting of a precision three-cup anemometer and a wind vane. Each sensor has a starting threshold of 0.5 mph and an accuracy of 1 percent over the range of 0-100 mph (wind speed), and three degrees over the range of 0-540 degrees (wind direction).

The equipment shelter consists of a trailer which is 4.3 meters (14 feet) long, 2.4 meters (8 feet) wide, and 3.1 meters (10 feet) high. A stable temperature within the shelter is maintained by electric heaters and air conditioners. The temperature is verified by a maximum/minimum thermometer mounted inside the shelter and by continuous temperature monitoring by the data logger.

The station has been operated in accordance with a site-specific Station Operating and Quality Assurance Procedures (SOQAP) manual (FPC, 1991a), previously submitted to and approved by FDER. The operating status of the equipment is tracked with station logs, equipment calibrations, computer data collection, and strip chart records. Other quality assurance procedures are performed in accordance with the specific SOQAP manual, which also describes internal quality control procedures, as well as data precision and accuracy calculation procedures. The quality assurance portion of the manual is specifically designed to meet the requirements of Appendix B of 40 CFR 58.

A systems audit and the first four quarterly performance audits of the air quality analyzers have been conducted by FDER. A PM_{10} audit conducted as part of EPA's National Performance

Audit Program has been completed and audits of the SO_2 and O_3 systems have been scheduled under this program. Three of the four quarterly data reports have been submitted to FDER.

5.3.2 On-site Hourly Ambient Air Quality Monitoring Data Analysis and Summary

5.3.2.1 Sulfur Dioxide (SO_2)

A tabulation of the hourly SO_2 concentrations measured at the on-site station during the period of October 15, 1991, through February 14, 1992, is presented in Appendix 10.5.6.3 of the site certification application (SCA) and summarized in Table 5-3. A total of 2,650 hourly averages were reported for a data recovery of 89.8 percent. As indicated in Table 5-3, SO_2 concentrations recorded for all averaging periods are well below the allowable NAAQS/FAAQS.

5.3.2.2 Ozone (O_3)

A tabulation of the hourly O_3 concentrations measured onsite during the period of October 15, 1991, through February 14, 1992, is presented in Appendix 10.5.6.3 of the SCA and summarized in Table 5-3. A total of 2,873 hourly averages were reported for a data recovery of 97.3 percent. As indicated in Table 5-3, the recorded values were well within the allowable NAAQS/FAAQS.

5.3.2.3 Particulate Matter (PM_{10})

Sampling for PM_{10} was performed on a once every sixth day basis. The monitoring results are summarized in Table 5-3 and presented in Appendix 10.5.6.4 of the SCA. The data indicate that background PM_{10} concentrations are well below the NAAQS and FAAQS. Twenty valid samples were recovered from the primary sampler for a data recovery of 100.0 percent.

5.3.3 Background Air Quality Data

Background air quality concentrations to be utilized in the modelling analysis were compiled from two sources - data collected on site and data from the 1990 FDER state air quality data base. The on-site data were used for SO_2, O_3, and PM_{10}. The data from the FDER data base were used for CO and NO_2. The FDER data base from the Tampa area was reviewed, and the sites with the highest concentrations for CO and NO_2 were selected as the background concentrations. This approach provided a conservative worst-case scenario, since these are urban monitoring locations, and actual concentrations in Polk County are undoubtedly less.

A summary of the background concentrations to be used in modelling air quality impacts are presented in Table 5-4.

5.3.4 On-site Hourly Meteorological Monitoring Data Analysis and Summary

5.3.4.1 Wind Speed (10 Meters)

The 10-meter wind speed data collected during the period of October 15, 1991, through February 14, 1992, are presented in Appendix 10.5.6.2 of the SCA. There were a total of 2,943 observations reported during this period, which represents a data recovery rate of 99.9 percent. The average wind speed during this period was 6.4 mph (2.9 m/sec). The maximum hourly average wind speed was 21.0 mph (9.4 m/sec).

5.3.4.2 Wind Direction (10 Meters)

The 10-meter wind direction data collected during the period of October 15, 1991, through February 14, 1992, are presented in Appendix 10.5.6.2 of the SCA. There were a total of 2,943 hourly averages reported for a data recovery rate of 99.9 percent. The prevailing winds during this period were from the northeast, north-northeast, and north, as shown in Figure 5-3, which is a wind rose for the four-month period.

TABLE 5-1

REGIONAL 1990 AMBIENT AIR QUALITY DATA

POLLUTANT	LOCATION	SITE #	CONCENTRATION ($\mu g/m^3$)				
			3-HOUR		24-HOUR		ANNUAL ARITHMETIC MEAN
			HIGH	2ND HI	HIGH	2ND HI	
SO_2	LAKELAND	2160004F02	122	122	42	27	5
	NICHOLS	3680010F02	341	252	66	62	9
	SARASOTA	4080002G01	245	224	62	42	6
	SARASOTA	4100012G01	103	98	45	43	8
	HILLSBOROUGH CO	1800021G02	411	388	85	80	15
	TAMPA	1800095G02	590	586	104	100	19
	N. RUSKIN	1800106J02	274	223	54	53	9
	N. RUSKIN	1800107J02	680	438	97	89	10
	TAMPA	4360035G02	369	322	143	105	21
	TAMPA	4360053G02	384	343	102	98	24

POLLUTANT	LOCATION	SITE #	CONCENTRATION ($\mu g/m^3$)		
			1-HOUR		ANNUAL ARITHMETIC MEAN
			HIGH	2ND HI	
O_3	HILLSBOROUGH BAY	1800081G03	231	219	
	TAMPA	4360035G02	242	219	
	TAMPA*	4360055G01	123	118	
	TAMPA**	4360065G01	268	213	
	CLEARWATER	0620004G01	237	213	
	ST. PETERSBURG	3980018G01	219	219	
	TARPON SPRINGS	4380002G03	251	204	
	SARASOTA	4080005G01	213	196	
	SARASOTA	4080005G01	200	200	

POLLUTANT	LOCATION	SITE #	CONCENTRATION ($\mu g/m^3$)
			ANNUAL ARITHMETIC MEAN
NO_2	TAMPA	4360064G01	25
	ST. PETERSBURG	3980018G01	24
	TARPON SPRINGS	4380002G03	17

POLLUTANT	LOCATION	SITE #	CONCENTRATION (ppm)				
			1-HOUR		8-HOUR		ANNUAL ARITHMETIC MEAN
			HIGH	2ND HI	HIGH	2ND HI	
CO	TAMPA	4360035G02	5	5	3	2	
	TAMPA	4360045G01	8	8	6	5	
	SEMINOLE HTS	4360060G01	12	10	7	6	
	TAMPA	4360064G01	9	9	5	3	
	LARGO	2260002G01	6	5	3	3	
	ST. PETERSBURG	3980018G01	11	9	6	5	
	ST. PETERSBURG	3980024G01	7	7	5	4	
	TARPON SPRINGS	4380002G03	5	5	2	2	
	SARASOTA	408000GG01	7	6	3	3	
	SARASOTA	4080004G01	11	10	6	6	

TABLE 5-1

REGIONAL 1990 AMBIENT AIR QUALITY DATA

POLLUTANT	LOCATION	SITE #	CONCENTRATION (μg/m^3)		
			24-HOUR		ANNUAL ARITHMETIC MEAN
			HIGH	2ND HI	
PM_{10}	GIBSONTON	1800066G02	72	68	37
	TAMPA	1800095G01	44	39	28
	TAMPA	4360002G01	49	41	29
	TAMPA	4360035G02	50	46	30
	TAMPA	4360035G09	48	46	29
	SEMINOLE HTS	4360060G01	70	50	31
	LARGO	2260004G02	56	50	27
	LARGO	2260004G09	59	48	28
	TARPON SPRINGS	4380002G03	33	32	20
	SARASOTA	4080003G01	54	50	27
	SARASOTA	4080003G09	52	47	27
	SARASOTA	4100013G01	41	35	21
	VENICE	4560001G01	68	60	36
	VENICE	4560001G09	56	51	36

POLLUTANT	LOCATION	SITE #	CONCENTRATION (μg/m^3)		
			24-HOUR		ANNUAL ARITHMETIC MEAN
			HIGH	2ND HI	
TSP	BRANDON	0370002G01	88	73	44
	RUSKIN	1800003G03	65	62	36
	GIBSONTON	1800066G02	129	119	78
	GARDINIER PARK	1800083G02	87	79	49
	HILLSBOROUGH CO	1800085G02	67	60	37
	TAMPA	1800095G01	114	94	61
	N. RUSKIN	1800106J02	58	58	40
	N. RUSKIN	1800107J02	85	77	39
	TAMPA	4360002G01	85	80	54
	TAMPA	4360002G09	90	79	54
	TAMPA	4360003G01	87	68	43
	SEMINOLE HTS	4360060G01	186	127	57
	TAMPA	4360060G09	174	122	55
	TAMPA	4360064G02	384	192	139
	TEMPLE TERRACE	4440001G01	64	52	33
	AUBURNDALE	0120001F01	169	68	46
	BARTOW	0180003F01	78	66	40
	LAKELAND	2160004F02	72	63	29
	NICHOLS	3680010F02	96	76	44
	SARASOTA	4080003G01 (2 OBS)	80	36	58
	SARASOTA	4100013G01 (8 OBS)	58	41	29
	SARASOTA	4100013G09 (4 OBS)	60	42	39

TABLE 5-1
REGIONAL 1990 AMBIENT AIR QUALITY DATA

POLLUTANT	LOCATION	SITE #	QUARTERLY ARITHMETIC AVG ($\mu g/m^3$)			
			JAN/ MAR	APR/ JUN	JUL/ SEPT	OCT/ DEC
Pb	RUSKIN	1800003603	0.0	0.0	0.0	0.0
	TAMPA	1800103G02	0.0	0.0	0.0	0.0
	HILLSBOROUGH CO	1800104G02	0.1	N/A	N/A	N/A
	HILLSBOROUGH CO	1800104G09	0.0	N/A	N/A	N/A
	TAMPA	4360002G09	0.1	0.0	0.1	0.0
	SEMINOLE HTS	4360060G01	0.0	0.0	0.0	0.0
	TAMPA	4360060G09	0.0	0.0	0.0	0.0
	TEMPLE TERRACE	4440001G01	0.1	0.0	0.0	0.0

Notes:
* January - April
** April - December

N/A - Not Available

Sources: FDER, 1992

TABLE 5-2
SUMMARY OF TAMPA ELECTRIC POLK COUNTY AIR QUALITY MONITORING DATA

Pollutant	Averaging Period	Highest Monitored Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	FAAQS ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	3-Hour	202	1,300	1,300
	24-Hour	42	365	260
	Annual *	7	80	60
Particulate Matter (PM_{10})	24-Hour	43	150	150
	Annual *	18	50	50
Ozone (O_3)	1-Hour	192	235	235

* April - December 1991

Period of Record: April 1, 1991 - December 31, 1991

Data Source: FDER, 1992, Air Quality Database Site # 103680036501

TABLE 5-3
SUMMARY OF POLK COUNTY SITE ON-SITE AIR QUALITY MONITORING DATA

Pollutant	Averaging Period	Highest Monitored Concentration ($\mu g/m^3$)	2nd Highest Monitored Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	FAAQS ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	3-Hour	86	78	1,300	1,300
	24-Hour	35	34	365	260
	4 Months (annual standard)	5	N/A	80	60
Particulate Matter (PM_{10})	24-Hour	37	24	150	150
	4 Months (annual standard)	17	N/A	50	50
Ozone (O_3)	1-Hour	149	149	235	235

Period of Record: October 15, 1991, through February 14, 1992

N/A - Not Applicable

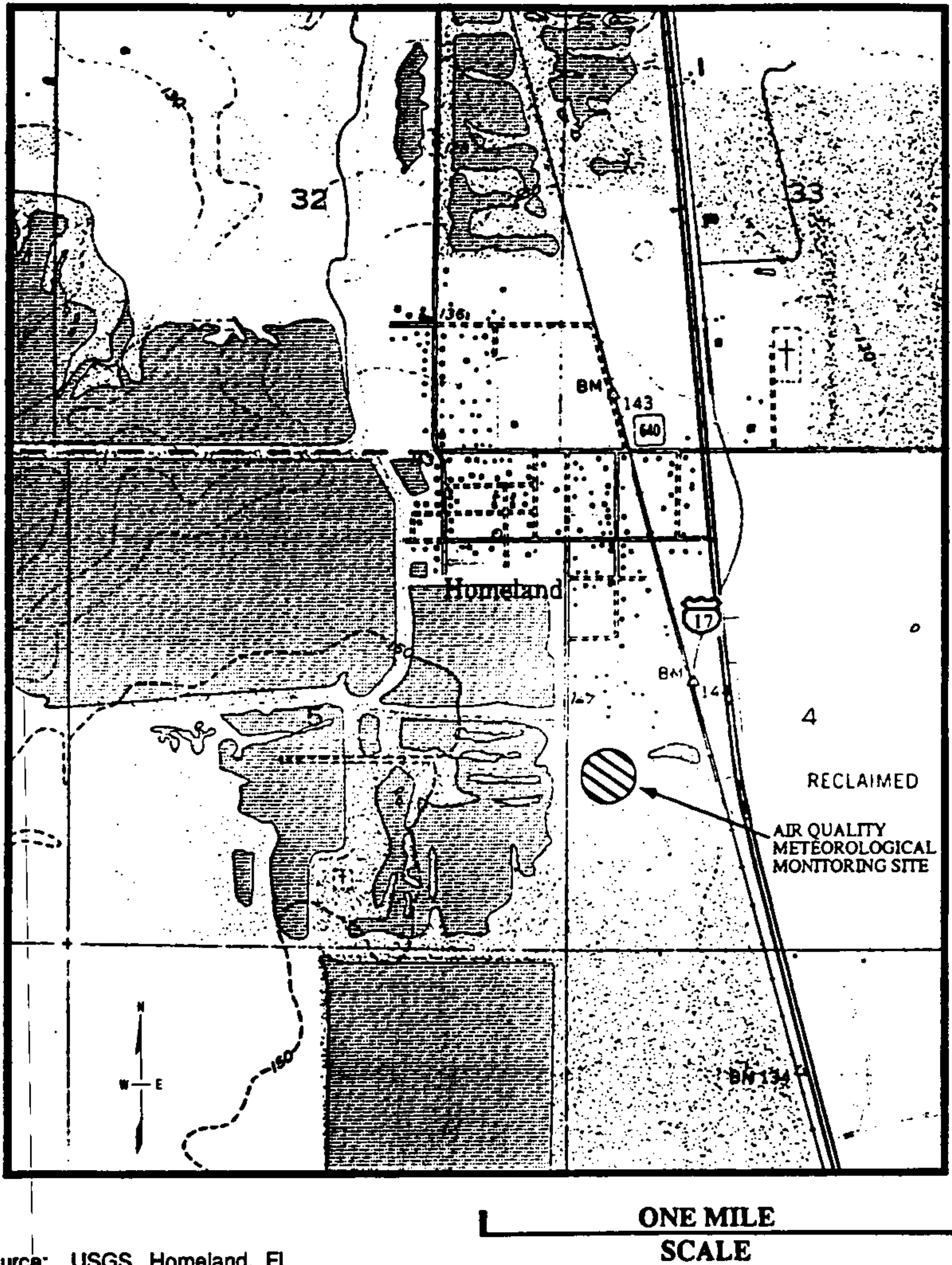
Source: Ebasco Environmental, 1992

TABLE 5-4
BACKGROUND AIR QUALITY DATA

Parameter		Averaging Period	Concentration [1] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	FAAQS ($\mu g/m^3$)
Carbon Monoxide (CO)	[2]	1-Hour	11,450	40,000	40,000
		8-Hour	6,870	10,000	10,000
Nitrogen Dioxide (NO_2)	[3]	Annual	25	100	100
Sulfur Dioxide (SO_2)	[4]	3-Hour	78	1,300	1,300
		24-Hour	34	365	260
		4 Months (annual standard)	5	80	60
Particulate Matter (PM_{10})	[4]	24-Hour	24	150	150
		4 Months (annual standard)	17	50	50
Ozone (O_3)	[4]	1-Hour	149	235	235

Note: [1] Second-highest (short-term) and highest annual (long-term) concentrations are presented

Sources:
[2] FDER Hillsborough Site 060G01 (1990)
[3] FDER Hillsborough Site 002G09 (1990)
[4] FPC Homeland AQ Station (10/15/91 through 02/14/92)

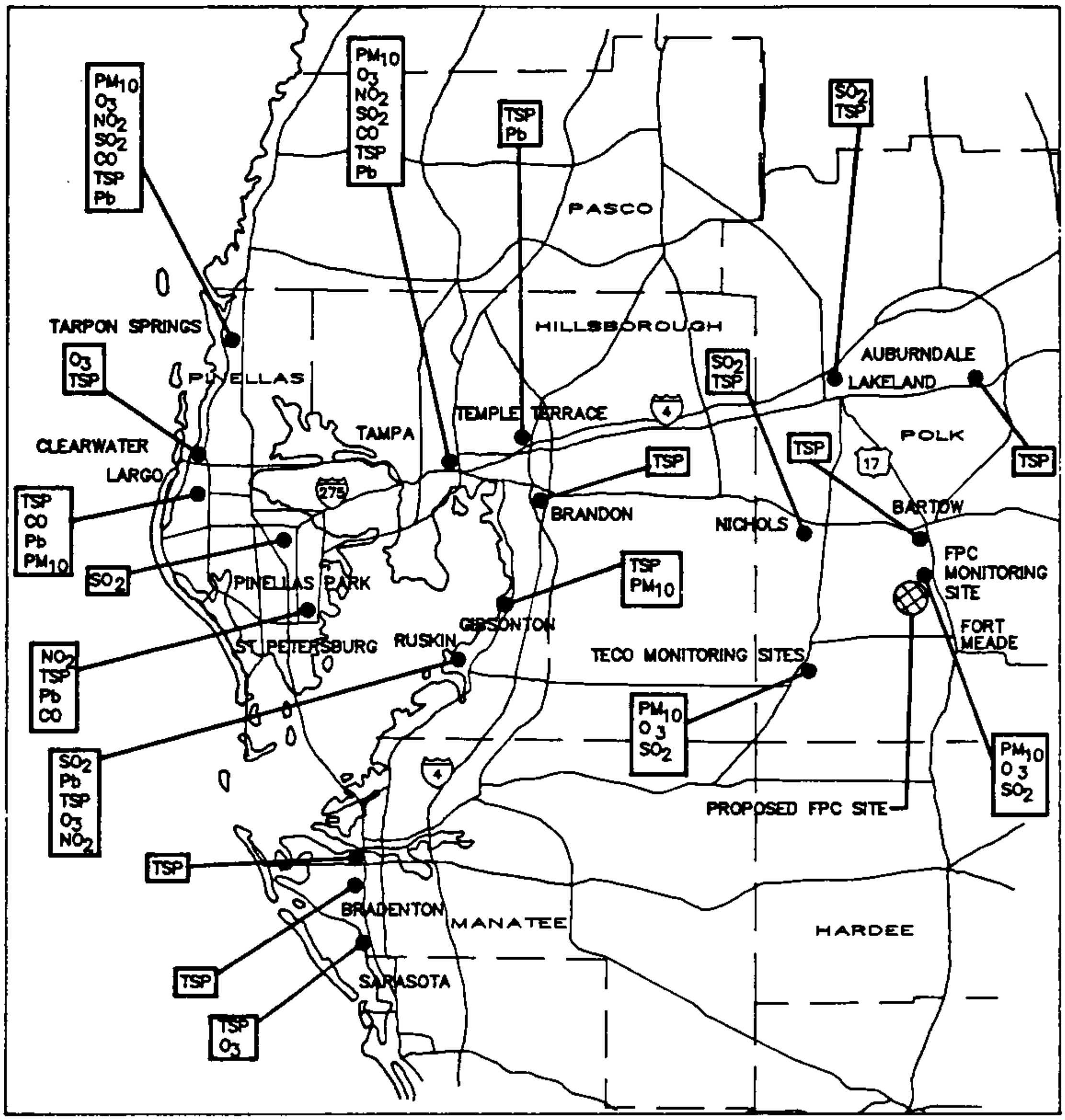


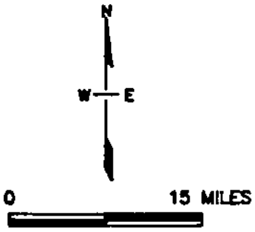
Source: USGS, Homeland, FL

Florida Power
CORPORATION

Polk County Site

FIGURE 5-1
AIR QUALITY/METEOROLOGICAL
MONITORING SITE LOCATION MAP



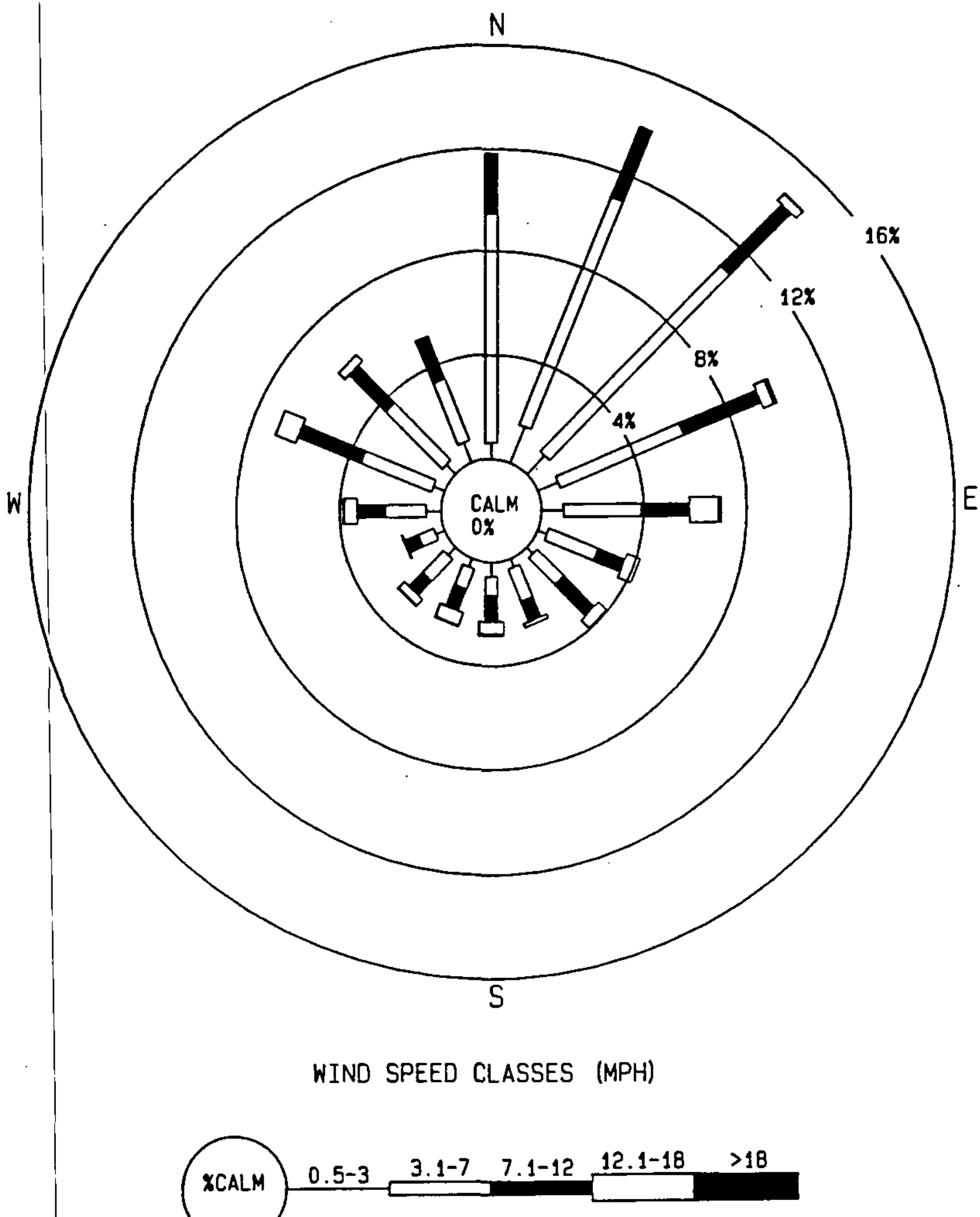


SOURCE: EBASCO ENVIRONMENTAL, 1992

Florida Power CORPORATION

Polk County Site

FIGURE 5-2
LOCATIONS OF FDER AND OTHER AMBIENT AIR QUALITY MONITORING SITES



Source: Ebasco Environmental, 1992

Florida Power CORPORATION

Polk County Site

FIGURE 5-3
ON-SITE WIND ROSE
(OCTOBER 15, 1991 - FEBRUARY 14, 1992)

6.0 AIR QUALITY MODELLING APPROACH

This section summarizes the air quality modelling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Included are descriptions of the models, meteorology, options selected, listings of modelling parameters for the proposed facilities and existing sources, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts.

The scope of the required modelling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 3.0, Table 2-5 (CO, NO_x, SO_2, PM, O_3, VOC, sulfuric acid mist, Be, benzene, and As). Not all of the pollutants will require the full PSD air quality analysis; for some, impact identification of the new facilities alone will be sufficient.

As indicated in Table 2-5, there will be a significant increase in VOC emissions, triggering PSD review for ozone. Ozone formation cannot be simulated with a simple Gaussian dispersion model. However, the U.S. EPA Guideline on Air Quality Models (EPA, 1990a) indicates that "the use of models incorporating complex chemical mechanisms should be considered only on a case-by-case basis with proper demonstration of applicability. These are generally regional models not designed for the evaluation of individual sources but used primarily for region-wide evaluations." Also, Rule 17-2.510(2)(a)2.a., F.A.C., specifies that although the proposed source is within the area of influence of the Tampa ozone nonattainment area, the proposed source is subject to permitting under the PSD rules rather than the nonattainment rules. Thus, the proposed facility is not subject to a VOC emissions impact assessment and an ozone modelling analysis is not appropriate.

The proposed source emissions of Be, benzene, sulfuric acid mist, and As are shown in Table 2-5 to be above the PSD significant emission rates. However, the PSD regulations do not define significant impact levels for these pollutants (except for Be) nor are ambient air quality standards established for these pollutants. Hence, the air quality impact assessment for these pollutants is limited to prediction of the maximum impacts from the proposed facility.

Some additional pollutants which are not subject to PSD review (and not regulated under the Clean Air Act) are included in the air quality impact analysis in order to provide additional information, and to serve as input to the additional impacts analyses in Section 8.0. The additional noncriteria pollutants for which emission estimates were available for this project (mainly trace elements) are: antimony, barium, boron, cadmium, calcium, chromium, cobalt, copper, magnesium, manganese, mercury, nickel, selenium, vanadium, and zinc. Emission estimates for these substances are presented in Section 4.0.

6.1 GENERAL MODELLING APPROACH

As required by the PSD regulations the air quality impact assessment consists of a proposed source significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following paragraphs under specific modelling methodologies. The modelling approach followed EPA and FDER modelling guidelines for determining compliance with applicable PSD increments and ambient air quality standards. A modelling protocol was prepared by the applicant and submitted to FDER for review (FPC, 1991b). The FDER approved the modelling protocol prior to commencement of the air quality impact assessment.

The use of a five-year meteorological data base in the modelling analysis allowed for a comparison of the predicted highest, second-highest short-term, and highest annual average concentrations to applicable short-term PSD increments and ambient air quality standards. The highest, second-highest concentration was calculated for a receptor field by:

- Eliminating the highest concentration predicted at each receptor;
- Identifying the second-highest concentration predicted at each receptor; and
- Selecting the highest concentration among those second-highest concentrations.

This approach is consistent with the ambient air quality standards and PSD increments which permit one short-term average exceedance per year at each receptor.

6.2 MODEL SELECTION AND OPTIONS

6.2.1 Dispersion Model Selection

The Polk County Site has been determined to be a rural area based upon the technique for urban/rural determinations documented in the EPA "Guideline on Air Quality Models" (EPA, 1990a) which applies land use criteria. Based upon this determination, the refined ISCST dispersion model (Version 90346) was selected for use in the air quality impact analysis used to support the PSD permit application. The ISCST model (EPA, 1987a) is a referenced EPA dispersion model recommended for use in rural areas, and for application to point, area, and volume sources. The ISCST model can predict the maximum as well as the highest, second-highest concentration and period of occurrence for 1-hour, 3-hour, 8-hour, 24-hour, and annual averaging periods at each receptor for each full year of hourly meteorological data used.

6.2.2 Dispersion Model Options

Table 6-1 provides a listing of the program control parameter data used in the ISCST model as approved by FDER. The ISCST model was applied without terrain adjustment data because the area in which the Polk County Site is located has very little relief (e.g., a net change in ground level elevation in the range of only 10 feet). The ISCST model's building downwash options were applied because the stacks for the proposed sources will be less than GEP stack height.

Based on a discussion with FDER personnel, the decision was made to collocate all four HRSG stacks for the proposed facility in the modelling analysis. The decision was also made to model emissions from the diesel generator and auxiliary boiler separately from the CC units (Section 6.8), since their emissions are small compared to the HRSG stacks' emissions and will not be operated when the CC units are in normal operation, except for very brief periods of testing. Hence, the total worst-case emissions for all proposed sources were assumed to be emitted from one stack having the HRSG stack parameters.

Because proposed sources were collocated for modelling purposes, emissions impacts for the proposed sources with respect to all applicable pollutants were scaled with reference to emissions of a single pollutant (SO_2). The ISCST model was run separately for the existing PSD sources and the existing baseline sources to determine those source impacts in combination with the proposed source impacts.

The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modelling analysis and makes for a conservative approach to modelling PM impacts.

6.3 METEOROLOGICAL DATA

The air quality modelling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Tampa, Florida, and concurrent twice-daily upper air soundings from Ruskin, Florida, for the years 1982-1986. The meteorological data were supplied by FDER in the preprocessed format required by the ISCST model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.7 meters, used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Tampa.

6.4 EMISSIONS INVENTORY

6.4.1 Proposed Sources

The proposed CC facility will have the capability of firing natural gas and low sulfur fuel oil. The fuel scenarios evaluated for the proposed source include natural gas firing at 100% load at 40°F, 72°F, and 95°F ambient temperature; and fuel oil firing at 100% load at 40°F, 72°F, and 95°F ambient temperature. The proposed facility will also include an auxiliary boiler capable of firing natural gas or fuel oil and a diesel generator firing diesel fuel.

The emissions inventories for the proposed sources and fuel scenarios identified above are presented in Tables 6-2 through 6-5. The pollutant emission rates shown in those tables are representative of BACT as demonstrated in Section 4.0. The air quality modelling analysis for the proposed sources assumed that maximum design capacity emissions represent actual emissions for purposes of determining PSD increment consumption.

The proposed source worst-case fuel scenario was determined by first modelling the scenario with the highest emissions (fuel oil, 100% load) to determine the worst-case emission scenario at all three ambient temperatures using a coarse receptor grid composed of 341 receptors and five years of meteorological data, as described above, in the ISCST model. The results of that analysis indicated 40°F to be generally the worst-case temperature.

6.4.2 Existing Sources

The results of the proposed source significant impact area analysis (which is described in Section 7.0) indicated that the proposed facility's air quality impacts could be above the significant impact levels only for SO_2 at off-site locations. The ISCST projected impact area for SO_2 was a 1.0 km radius circle from the proposed source. Therefore, the PSD and background source emission inventories for this pollutant were prepared from available databases considering this small area of impact.

The FDER Air Pollutant Information System (APIS) computer printouts of the emissions for facilities located within approximately a 50 km radius of the proposed source location were searched. This information was supplemented with data from air quality permits, PSD permit applications, and previous air quality modelling analyses to identify all significant sources (emissions greater than 25 tons/year) within the 50 km radius.

A screening technique known as the "Screening Threshold" method (North Carolina DNR, 1985) was applied to sources located within 50 km from the Polk County Site. The method is designed to eliminate objectively from the emission inventory those sources which are not likely to have a significant interaction with the source undergoing evaluation. According to the method, sources that should be considered in the modelling analyses are those with emissions greater than Q (in tons/year), which is calculated by the following equation:

$$Q = 20 \times D$$

where:

D = the distance in kilometers from the particular source to the source undergoing evaluation.

Those sources with maximum allowable emissions below the calculated "screening threshold" were eliminated from consideration in the modelling analysis. The remaining sources not screened out comprised the existing source emission inventory to be used in the modelling analysis.

The existing source emission inventory for SO_2 was also sorted with respect to PSD increment consuming sources and all sources for the AAQS analysis. In general, the PSD regulations define PSD sources as those sources which commenced construction after the baseline date for a specified pollutant. Baseline sources are defined as those sources which commenced construction prior to the baseline date for a specified pollutant. In a discussion with FDER (Linn, 1992), the PSD baseline date for major sources (greater than 100 tons/year) of SO_2 was indicated as January 6, 1975, and the minor source (less than 100 tons/year) PSD baseline date for this pollutant is December 27, 1977.

The existing PSD source and AAQS source emission inventories were based on stack collocation wherever reasonable. Multiple-stack facility emissions were combined and assumed to be emitted from the stack with the lowest "*K*" factor, an arbitrary parameter accounting for the relative influence of stack height, plume rise, and emission rate on concentrations (EPA, 1977). The parameter, *K*, was computed using the following formula:

$$K = hVT_S / Q$$

where:

h = stack height (m)
V = stack gas volume flow rate = $(\pi/4)d^2 V_S$ (m^3/sec)
d = stack exit diameter (m)
V_S = stack gas exit velocity (m/sec)
T_S = stack gas exit temperature (°K)
Q = pollutant emission rate (g/sec)

For example, application of this method to Source No. 11, Table 6-7 provided the following "*K*" factors, indicating that the stack parameters for the third source listed would be used for modelling that facility.

K FACTOR EXAMPLE FOR SOURCE NO. 11, TABLE 6-7

Stack Height (*m*)	**Stack Diameter (*m*)**	**Stack Temperature (°*K*)**	**Exit Velocity (*m/sec*)**	**Emission Rate (*g/sec*)**	**"*K*" Factor**
23.2	1	349.7	20.1	11.5	11137
20.7	1	458	11.3	8.3	10137
18.9	1.1	458	9.5	8	9769

The completed existing source emission inventories were submitted to FDER for review and were determined to be acceptable for input to the ISCST model (Linn, 1992a and b). The PSD source and AAQS source emission inventories used in the air quality modelling analysis are presented in Tables 6-6 and 6-7, respectively. The emissions for all applicable pollutants in those tables are in terms of maximum allowable or potential emissions in order to evaluate a worst-case emissions scenario for those sources from both an ambient standard and PSD increment impact standpoint. The locations for all existing PSD sources and AAQS sources selected for modelling are shown in Figures 6-1 and 6-2, respectively.

A separate source inventory was used for the analysis of impacts on the nearest Class I PSD area, the Chassahowitzka Wilderness Area. The source inventory for the Class I PSD analysis (Table 6-8) consisted of not only the PSD sources within 50 km of the proposed source but also a large number of additional PSD increment consuming sources in the area. It was compiled from a source list provided by FDER and additional inventories and was reviewed and approved by FDER (Linn, 1992a and b). A depiction of these source locations is provided in Figure 6-3.

6.5 RECEPTOR LOCATIONS

The general modelling approach discussed previously considered an area of impact analysis and a refined modelling analysis to assess air quality impacts on the applicable ambient air quality standards and PSD increments (i.e., no screening phase analysis was performed due to the small area of impact). A description of the receptor grids used in each of these modelling analyses is presented below.

6.5.1 Receptor Grid for Proposed Source Significant Impact Area Analysis

This modelling analysis used a receptor grid consisting of a polar grid beginning at 2.5 km and extending out to cover a 50 km radius centered over the proposed source. The polar grid consisted of 36 radials, each separated by 10-degree increments and extending outward at ring distances of 2.5, 5.0, 10.0, 15.0, 20.0, 25.0, 30.0, 35.0, 40.0, 45.0, and 50.0 km with reference to the proposed source location. This receptor grid consisted of a total of 396 receptors and is shown in Figure 6-4.

When the modelling exercise with this grid indicated no significant impact for any pollutant at the 2.5 km ring, additional rings were added at 100-meter resolution moving in to the closest plant boundary (at 500 meters to the south). This modelling eventually indicated a significant impact for SO_2 only extending out to 1,000 meters. Because of the small area involved, the usual coarse grid analysis was dispensed with and only a fine grid analysis was performed.

6.5.2 Fine Grid for Refined Phase Modelling Analysis

This modelling analysis used a polar receptor grid covering a small area just outside of the plant boundary and within 1.0 km of the proposed source. This receptor grid had a grid resolution of 0.1 km and consisted of 45 receptors. This grid, depicted in Figure 6-5, is to the south of the proposed source.

6.5.3 Receptor Grid for Class I PSD Analysis

The modelling for the PSD Class I area analysis used a 13-point receptor grid obtained from FDER. This grid consists of a series of points located along the boundary of the Class I area. The coordinates of these points are listed in Table 6-9.

6.6 BACKGROUND CONCENTRATIONS

The background concentrations for SO_2 were determined according to the procedure documented at Section 9.2.3 in the modelling guidelines (EPA, 1987). This procedure calls for a determination of a modelled background concentration component and an ambient air quality monitoring data-derived background concentration component. The modelled background concentration component was derived from the modelled impact for all applicable background sources identified in Table 6-2.

The ambient air quality monitoring data-derived background concentration component was based on ambient air quality monitoring data from the on-site PSD monitoring program discussed in Section 5.0. The highest or second-highest monitored concentration for each applicable criteria air pollutant and averaging time was selected based on the four months of on-site monitoring data summarized in Table 5-4.

The total background concentrations for SO_2 were determined by modelling all applicable background sources, and adding the monitored concentration as discussed above. This approach results in possible "double counting" the impacts of the existing sources since their impacts may also be accounted for in the monitoring data. However, it is a simple approach, is conservative, and was approved by the FDER (Linn, 1991). The total background concentrations are summarized under the results of the modelling analysis in Section 7.0.

6.7 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with structures planned at the Polk County Site, the 34.4 meter stacks for the proposed CC units will be less than the calculated GEP value (45.7 meters). Therefore, the potential for building downwash to occur was considered in the modelling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide (EPA, 1987a). The building height, length, and width are input to the model, which uses these parameters to modify the analyses. 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.

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 modelled, then the value input to the model must be adjusted according to the following formula:

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

$$M_W = 0.886W$$

where:

M_W = Input to the model to produce a building width of W used in the dispersion calculation

W = The actual building width

In the case of the proposed CC units, the HRSG structures are the dominant buildings of influence. The dimensions of the HRSG structures are 22.86 meters high (H_b) and 26.6 meters wide (M_w). Since the proposed stack height of 34.4 meters is more than $H_b + 0.5\ L_b$, only the Huber-Snyder downwash algorithm is used by the ISCST model.

6.8 AUXILIARY BOILER AND DIESEL GENERATOR MODELLING

Emissions from both the auxiliary boiler and diesel generator were assumed to be collocated and were modelled separately from the CC units using the general approach as described in Section 6.1. The refined ISCST dispersion model (Version 90346) identified in Section 6.2.1 was used; Table 6-1 provides a listing of the program control parameter data. The meteorological data used in the air quality modelling analysis is the same as that identified in Section 6.3. The emission inventories for the auxiliary boiler and the diesel generator have been presented in Tables 6-4 and 6-5, respectively. Receptor locations for both sources are identical to those identified in Section 6.5. The overall results of modelling are presented in Section 7.1.

TABLE 6-1

POLK COUNTY SITE ISCST MODEL PROGRAM CONTROL PARAMETER DATA (Page 1 of 2)

Calculate (concentration = 1, deposition = 2)	ISW(1)	=	1
Receptor grid system (cartesian = 1 or 3, polar = 2 or 4)	ISW(2)	=	1,3,4
Discrete receptor system (cartesian = 1, polar = 2)	ISW(3)	=	1,2
Terrain elevations are read (yes = 1, no = 0)	ISW(4)	=	0
Calculations are written to tape (yes = 1, no = 0)	ISW(5)	=	0,1
List all input data (no = 0, yes = 1, met data also = 2)	ISW(6)	=	1,2
Complete average concentration (or total deposition) with the following time periods:			
Hourly (yes = 1, no = 0)	ISW(7)	=	0,1
2-hour (yes = 1, no = 0)	ISW(8)	=	0
3-hour (yes = 1, no = 0)	ISW(9)	=	0,1
4-hour (yes = 1, no = 0)	ISW(10)	=	0
6-hour (yes = 1, no = 0)	ISW(11)	=	0
8-hour (yes = 1, no = 0)	ISW(12)	=	0,1
12-hour (yes = 1, no = 0)	ISW(13)	=	0
24-hour (yes = 1, no = 0)	ISW(14)	=	0,1
Print "N" - day tables (yes = 1, no = 0)	ISW(15)	=	1
Print the following types of tables whose time periods are specified by ISW(7) through ISW (14):			
Daily tables (yes = 1, no = 0)	ISW(16)	=	0,1
Highest and second-highest tables (yes = 1, no = 0)	ISW(17)	=	0,1
Maximum 50 tables (yes = 1, no = 0)	ISW(18)	=	0,1
Meteorological data input method (preprocessed = 1, card = 2)	ISW(19)	=	1
Rural-urban option (ru. = 0, ur. mode 1 = 1, ur. mode 2 = 2, ur. mode 3 = 3)	ISW(20)	=	0
Wind profile exponent values (defaults = 1, user enters = 2,3)	ISW(21)	=	1
Vertical pot. temp. gradient values (defaults = 1, user enters = 2,3)	ISW(22)	=	1
Scale emission rates for all sources (no = 0, yes > 0)	ISW(23)	=	0
Program calculates final plume rise only (yes = 1, no = 2)	ISW(24)	=	1
Program adjusts all stack heights for downwash (yes = 2, no = 1)	ISW(25)	=	2
Program uses buoyancy induced dispersion (yes = 1, no = 2)	ISW(26)	=	1

TABLE 6-1 (Continued)

POLK COUNTY SITE ISCST MODEL PROGRAM CONTROL PARAMETER DATA (Page 2 of 2)

Concentrations during calm periods set = 0 (yes = 1, no = 2)	ISW(27) =	1
Regulatory default option chosen (yes = 1, no = 2)	ISW(28) =	1
Type of pollutant to be modeled (1 = SO_2, 2 = other)	ISW(29) =	1
Debug option chosen (yes = 1, no = 2)	ISW(30) =	2
Above ground (flagpole) receptors used (yes = 1, no = 0)	ISW(31) =	0
Number of input sources	NSOURC =	variable
Number of source groups (=0, all sources)	NGROUP =	variable
Time period interval to be printed (=0, all intervals)	IPER =	0
Number of X (range) grid values	NXPNTS =	variable
Number of Y (theta) grid values	NYPNTS =	variable
Number of discrete receptors	NXWYPT	=variable
Source emission rate units conversion factor	TK =	1×10^6
Height above ground at which wind speed was measured	ZR =	6.7 meters
Logical unit number of meteorological data	IMET =	9
Decay coefficient for physical or chemical depletion	DECAY =	0.0
Surface met. station number	ISS =	12842
Year of surface met. data	ISY =	1982 - 1986
Upper air met. station number	IUS =	12842
Year of upper air met. data	IUY =	1982 - 1986

Source: Ebasco Environmental, 1992

TABLE 6-2
PROPOSED SOURCE EMISSIONS INVENTORY
NATURAL GAS AT 40°F, 72°F, AND 95°F AMBIENT TEMPERATURE

Source ID Number (1)	UTM Coordinates (km)		Stack Parameters (2)				Emission Rates (grams/sec)			
	East	North	H_s (m)	T_s (°K)	V_s (m/sec)	D_s (m)	SO_2	PM	NO_x	CO
40°F:										
CC 1	414.40	3,073.91	34.4	366	35.3	4.1	0.13	1.14	9.58	10.09
CC 2	414.34	3,073.91	34.4	366	35.3	4.1	0.13	1.14	9.58	10.09
CC 3	414.28	3,073.91	34.4	366	35.3	4.1	0.13	1.14	9.58	10.09
CC 4	414.22	3,073.91	34.4	366	35.3	4.1	0.13	1.14	9.58	10.09
CC (3)	414.40	3,073.91	34.4	366	35.3	4.1	0.52	4.56	38.32	40.36
72°F:										
CC 1	414.40	3,073.91	34.4	366	33.1	4.1	0.12	1.14	8.83	9.21
CC 2	414.34	3,073.91	34.4	366	33.1	4.1	0.12	1.14	8.83	9.21
CC 3	414.28	3,073.91	34.4	366	33.1	4.1	0.12	1.14	8.83	9.21
CC 4	414.22	3,073.91	34.4	366	33.1	4.1	0.12	1.14	8.83	9.21
CC (3)	414.40	3,073.91	34.4	366	33.1	4.1	0.48	4.56	35.32	36.84
95°F:										
CC 1	414.40	3,073.91	34.4	366	31.5	4.1	0.11	1.14	8.20	8.83
CC 2	414.34	3,073.91	34.4	366	31.5	4.1	0.11	1.14	8.20	8.83
CC 3	414.28	3,073.91	34.4	366	31.5	4.1	0.11	1.14	8.20	8.83
CC 4	414.22	3,073.91	34.4	366	31.5	4.1	0.11	1.14	8.20	8.83
CC (3)	414.40	3,073.91	34.4	366	31.5	4.1	0.44	4.56	32.80	35.32

(1) CC = Combined cycle combustion turbine / heat recovery steam generator

(2) Stack height = H_S; stack exit temperature = T_S; stack exit velocity = V_S; and stack exit diameter = D_S

(3) The receptor grid reference coordinates for the collocated stack are: x, +99 m; y, +29 m, based on a receptor grid zero point of 414.300 km east; 3,073.880 km north.

Source: Black & Veatch, 1992

TABLE 6-3
PROPOSED SOURCE EMISSIONS INVENTORY
FUEL OIL AT 40°F, 72°F, AND 95°F AMBIENT TEMPERATURE

Source ID Number [1]	UTM Coordinates (km)		Stack Parameters [2]				Emission Rates (grams/sec)			
	East	North	H_s (m)	T_s (°K)	V_s (m/sec)	D_s (m)	SO_2	PM	NO_x	CO
40°F:										
CC 1	414.40	3,073.91	34.4	400	40.5	4.1	12.36	2.14	40.10	12.11
CC 2	414.34	3,073.91	34.4	400	40.5	4.1	12.36	2.14	40.10	12.11
CC 3	414.28	3,073.91	34.4	400	40.5	4.1	12.36	2.14	40.10	12.11
CC 4	414.22	3,073.91	34.4	400	40.5	4.1	12.36	2.14	40.10	12.11
CC [3]	414.40	3,073.91	34.4	400	40.5	4.1	49.44	8.56	160.40	48.44
72°F:										
CC 1	414.40	3,073.91	34.4	400	37.79	4.1	11.35	2.14	36.70	11.22
CC 2	414.34	3,073.91	34.4	400	37.79	4.1	11.35	2.14	36.70	11.22
CC 3	414.28	3,073.91	34.4	400	37.79	4.1	11.35	2.14	36.70	11.22
CC 4	414.22	3,073.91	34.4	400	37.79	4.1	11.35	2.14	36.70	11.22
CC [3]	414.40	3,073.91	34.4	400	37.79	4.1	45.40	8.56	146.80	44.88
95°F:										
CC 1	414.40	3,073.91	34.4	400	35.7	4.1	10.47	2.14	34.18	10.59
CC 2	414.34	3,073.91	34.4	400	35.7	4.1	10.47	2.14	34.18	10.59
CC 3	414.28	3,073.91	34.4	400	35.7	4.1	10.47	2.14	34.18	10.59
CC 4	414.22	3,073.91	34.4	400	35.7	4.1	10.47	2.14	34.18	10.59
CC [3]	414.40	3,073.91	34.4	400	35.7	4.1	41.88	8.56	136.72	42.36

[1] CC = Combined cycle combustion turbine / heat recovery steam generator

[2] Stack height = H_S; stack exit temperature = T_S; stack exit velocity = V_S; and stack exit diameter = D_S

[3] The receptor grid reference coordinates for the collocated stack are: x, +99 m; y, +29 m, based on a receptor grid center point of 414.300 km east; 3,073.880 km north.

Source: Black & Veatch, 1992

TABLE 6-4
PROPOSED SOURCE EMISSIONS INVENTORY
AUXILIARY BOILER

Source ID Number[1]	UTM Coordinates (km)		Stack Parameters[2]				Emission Rates (grams/sec)			
	East	North	H_s (m)	T_s (°K)	V_s (m/sec)	D_s (m)	SO_2	PM	NO_x	CO
AB 1 (gas)	414.36	3,073.92	18.3	440	33.23	0.76	0.0081	0.063	1.25	0.62
AB 1 (fuel oil)	414.36	3,073.92	18.3	438	32.32	0.76	0.66	0.62	2.50	0.62

(1) AB = Auxiliary boiler
(2) Stack height = H_S; stack exit temperature = T_S; stack exit velocity = V_S; and stack exit diameter = D_S

Source: Black & Veatch, 1992

TABLE 6-5
PROPOSED SOURCE EMISSIONS INVENTORY
DIESEL GENERATOR — FUEL OIL

Source ID Number[1]	UTM Coordinates (km)		Stack Parameters[2]				Emission Rates (grams/sec)			
	East	North	H_s (m)	T_s (°K)	V_s (m/sec)	D_s (m)	SO_2	PM	NO_x	CO
DG 1	414.43	3,074.01	7.6	800	43.6	0.46	0.11	0.061	6.68	1.51

(1) DG = Diesel generator
(2) Stack height = H_S; stack exit temperature = T_S; stack exit velocity = V_S; and stack exit diameter = D_S

Source: Black & Veatch, 1992

TABLE 6-6
EXISTING SOURCE EMISSIONS INVENTORY
PSD SOURCES — PHASE I SO_2

No.	Source Name	UTM Coordinates (km)		Maximum Allowable SO_2 Emission Rates		Distance from Polk County Site (km)	Screen (Q = 20 × D)	Model Source? (Yes/No)
		East	North	(g/sec)	(tpy)			
1.	Agrico — S. Pierce (2 Sources)	407.5	3,071.5	37.9	1,316	7.1	142	Yes
2.	AMAX (Mobil) — Big 4 Mine (2 Sources)	394.9	3,069.8	17.0	589	19.7	395	Yes
3.	CF Industries (Cent. Phos) (4 Sources)	388.0	3,116.0	8.4	292	49.6	992	No
4.	CF — Bartow (3 Sources)	408.5	3,083.0	-53.5	-1,858	10.7	215	Yes
5.	City of Lakeland — Combustion Turbine	409.2	3,102.8	29.1	1,011	29.3	587	Yes
6.	City of Lakeland — McIntosh (3 Sources)	408.5	3,105.8	500.5	17,369	32.4	648	Yes
7.	Conserve (2 Sources)	398.7	3,084.2	26.8	931	18.6	372	Yes
8.	Farmland (3 Sources)	409.5	3,080.1	54.6	1,896	7.8	156	Yes
9.	Hillsborough County Resource Recovery Facility	368.2	3,092.7	21.4	743	49.7	994	No
10.	IMC — Ft. Lonesome (2 Sources)	389.6	3,067.9	39.6	1,375	25.3	506	Yes
11.	IMC — New Wales (10 Sources)	396.7	3,079.4	140.3	4,869	18.3	367	Yes
12.	Mobil — Nichols	398.4	3,085.3	2.4	85	19.5	390	No
13.	Royster (2 Sources)	406.8	3,085.1	-222.1	-7,707	13.4	268	Yes
14.	TECO — Hardee Station	404.8	3,057.4	277.8	9,641	19.0	380	Yes
15.	US Agrichem — Ft. Meade (3 Sources)	416.2	3,068.7	47.2	1,639	5.6	111	Yes
16.	WR Grace — Seminole	409.5	3,086.5	72.1	2,501	13.4	269	Yes
17.	WR Grace — Seminole (2 Sources)	409.7	3,086.0	-142.5	-4,946	12.9	258	Yes

Source: Ebasco Environmental, 1992

TABLE 6-7
EXISTING SOURCE EMISSIONS INVENTORY
AAQS SOURCES — PHASE I SO_2

(Page 1 of 2)

No.	Source Name	UTM Coordinates (km)		Maximum Allowable SO_2 Emission Rates		Distance from Polk County Site (km)	Screen (Q = 20 × D)	Model Source? (Yes/No)
		East	North	(g/sec)	(tpy)			
1.	Adams Packing	421.1	3,104.2	207	94	31.2	624	No
2.	Agrico — Pierce	403.7	3,079.0	12.0	417	11.7	233	Yes
3.	Agrico — S. Pierce	407.5	3,071.5	100.7	3,498	7.1	142	Yes
4.	Alcoma Packing	451.6	3,085.5	9.4	328	39.2	783	No
5.	AMAX (Mobil) — Big 4 Mine	394.7	3,096.6	16.4	569	20.0	399	Yes
6.	American Orange Corp.	429.8	3,047.3	5.7	198	30.8	617	No
7.	Bordo Citrus	427.8	3,097.5	1.8	60	27.2	545	No
8.	Brewer/Pavex Co.	413.0	3,086.2	2.2	75	12.4	247	No
9.	CF Industries	388.0	3,116.0	204.5	7,096	49.4	988	Yes
10.	CF — Bartow	408.4	3,082.4	155.4	5,394	10.3	206	Yes
11.	Citrus Hill	447.9	3,068.3	27.8	410	34.2	683	No
12.	Citrus World	441.0	3,087.3	25.3	877	30.0	599	Yes
13.	City of Lakeland — Larsen Station	409.0	3,106.2	115.2	3,998	32.7	654	Yes
14.	City of Lakeland — McIntosh Station	409.2	3,106.2	869.6	30,176	32.7	654	Yes
15.	Coca Cola	421.6	3,103.7	3.4	119	30.7	614	No
16.	Conserve — Nichols	398.7	3,084.2	45.6	1,582	18.6	372	Yes
17.	Consolidated Minerals	393.8	3,096.3	23.5	817	30.3	606	Yes
18.	Farmland — Green Bay	409.5	3,080.1	110.2	3,825	7.8	156	Yes
19.	FPC — Avon Park	451.4	3,050.5	1.7	58	43.9	879	No
20.	Gardinier Mine (Cargil) — Ft. Meade	415.3	3,063.3	33.8	1,173	10.7	213	Yes
21.	Hillsborough County Resource Recovery Facility	368.2	3,092.7	25.7	893	49.7	994	No
22.	Holly Hill Fruit	441.0	3,115.4	11.5	398	49.4	988	No

TABLE 6-7 (Continued)
EXISTING SOURCE EMISSIONS INVENTORY
AAQS SOURCES — PHASE I SO_2

(Page 2 of 2)

No.	Source Name	UTM Coordinates (km)		Maximum Allowable SO_2 Emission Rates		Distance from Polk County Site (km)	Screen (Q = 20 × D)	Model Source? (Yes/No)
		East	North	(g/sec)	(tpy)			
23.	IMC — Lonesome Mine	389.6	3,067.9	44.6	1,547	25.3	506	Yes
24.	IMC — New Wales	396.7	3,079.4	304.4	10,561	18.3	367	Yes
25.	IMC — Noralyn	414.7	3,080.3	14.6	505	6.4	128	Yes
26.	IMC — Prairie	402.9	3,087.0	3.9	137	17.3	346	No
27.	International Petroleum	389.0	3,098.0	1.8	61	34.9	697	No
28.	John Carlo — Florida	426.2	3,104.1	1.0	33	32.5	650	No
29.	Kaplan Industries	418.3	3,079.3	9.7	337	6.8	136	Yes
30.	Laidlaw Environmental Services	422.7	3,091.9	7.0	240	19.9	398	No
31.	Mobil — Nichols	398.4	3,085.3	25.9	898	19.5	390	Yes
32.	Owens — Illinois Glass	406.0	3,102.3	0.6	21	29.6	591	No
33.	Royster — Mulberry	406.8	3,085.1	36.5	1,265	13.4	268	Yes
34.	TECO — Big Bend	361.9	3,075.0	6,842.7	237,646	52.3	1,046	Yes
35.	TECO — Gannon	360.0	3,087.5	3,658.2	126,940	55.9	1,118	Yes
36.	TECO — Hardee Station	404.8	3,057.4	463.4	16,081	19.0	380	Yes
37.	TECO — Hookers PT	358.0	3,091.0	389.7	13,522	58.7	1,175	Yes
38.	US Agrichem — Bartow	413.2	3,086.3	12.2	423	12.4	249	Yes
39.	US Agrichem — Ft. Meade	416.0	3,069.0	78.1	2,710	5.2	104	Yes
40.	Wachula City Power	418.4	3,047.0	5.2	180	27.2	545	No
41.	WR Grace — Seminole	409.8	3,086.6	250.0	8,674	13.4	269	Yes

Source: Ebasco Environmental, 1992

TABLE 6-8
EXISTING SOURCE EMISSIONS INVENTORY
CLASS I PSD SOURCES — SO_2

(Page 1 of 3)

No.	Name	UTM Coordinates		Distance from Polk County Site (km)	Nearest Class I Receptor (km)	Maximum Allowable SO_2 Emission Rates	
		East	North			(g/sec)	(TPY)
1	FPC/Debary Prop Turbines (No PSD #)	467.5	3197.2	134.3	125.2	466.4	16199
2	FPC Intercession City Prop. Turbines 7 EAs (#180)	446.3	3126.0	61.2	113.2	310.9	10798
3	FPC Intercession City Prop. Turbines 7 EAs (#180)	446.3	3126.0	61.2	113.2	276.1	9589
4	Florida Crushed Stone Kiln 1 * changed 12/26/91 (#90, #91)	360.0	3162.4	103.8	20.0	98.4	3418
5,7	CF Ind. Baseline C, D (Increment Expanding)	388.0	3116.0	49.6	68.9	-100.8	-3501
6,8	CF Ind. Proposed C, D ((#155)	388.0	3116.0	49.6	68.9	109.2	3793
9	Florida Mining & Materials Kiln 2 (#124)	356.2	3169.9	112.2	14.6	1.4	50
10	TECO Big Bend- Unit 4 (#040)	361.9	3075.0	52.3	93.2	654.7	22739
11	TECO Big Bend- Units 1 & 2 (24-hr) *combined 1/3/92 (Exp.)	361.9	3075.0	52.3	93.2	-2,436.1	-84605
12	TECO Big Bend- Unit 3 (24-hr) (Increment Expanding)	361.9	3075.0	52.3	93.2	-1,218.1	-42303
13	Pasco County Resource Recovery Facility (#127)	347.1	3139.2	93.6	27.4	14.1	490
14,15	FPC - Crystal River 4, 5 (#33)	334.2	3204.5	153.2	21.1	2,017.7	70074
16	FPC - Crystal River 1 (Increment Expanding)	334.2	3204.5	153.2	21.1	-314.0	-10906
17	FPC - Crystal River 2 (Increment Expanding)	334.2	3204.5	153.2	21.1	-1,859.1	-64565
18	Orlando Utility Stanton 1 (#84)	483.5	3150.6	103.4	142.5	105.4	3661
19	Orlando Utility Stanton 2 24 hr (#84)	483.5	3150.6	103.4	142.5	242.4	8419
20	Kissimmee Utility Existing (#182)	460.1	3129.3	71.9	125.2	32.1	1115
21	TECO Hardee Station (#140)	404.8	3057.4	19.0	126.1	277.6	9641
22	Stauffer (Shut Down) (Increment Expanding)	325.6	3116.7	98.4	51.2	-52.1	-1808
23	City of Lakeland - McIntosh 3 (#008)	408.5	3105.8	32.4	90.8	500.1	17369
24	Hillsborough County Resource Recovery Facility (#104)	368.2	3092.7	49.7	78.1	21.4	743
25	Pinellas County Resource Recovery Facility (#098, #11)	335.3	3084.4	79.6	81.5	62.3	2162
26	Evans Packing (Shut Down)	383.3	3135.8	69.2	52.4	0.0	0

TABLE 6-8
EXISTING SOURCE EMISSIONS INVENTORY
CLASS I PSD SOURCES — SO_2

(Page 2 of 3)

No.	Name	UTM Coordinates		Distance from Polk County Site (km)	Nearest Class I Receptor (km)	Maximum Allowable SO_2 Emission Rates	
		East	North			(g/sec)	(TPY)
27	Asphalt Pavers No. 4 *changed 1/3/92 * changed 12/26/91	361.4	3168.4	108.3	20.0	2.2	78
28	Asphalt Pavers No. 3 *changed 1/3/92 * added 12/26/91	359.9	3162.4	103.8	19.9	2.2	78
29	City of Lakeland - Combustion Turbines (#166)	409.2	3102.8	29.3	93.3	29.1	1011
30	IMC - New Wales SAP #1, 2, 3 Baseline (Increment Expanding)	396.6	3078.9	18.3	103.5	-170.1	-5908
31	IMC - New Wales SAP #1, 2, 3 Projected (#170)	396.6	3078.9	18.3	103.5	182.9	6351
32	IMC - New Wales SAP #4, 5 Projected (#170)	396.6	3078.9	18.3	103.5	121.9	4234
33	IMC - New Wales DAP (#114)	396.6	3078.9	18.3	103.5	5.5	192
34	Proposed Pasco County Cogeneration Facility (#177)	385.6	3139.0	71.1	52.6	5.0	175
35	Proposed Lake County Cogeneration Facility (#176)	434.0	3198.8	126.5	92.6	5.0	175
36	CF Bartow Retired SAP (Increment Expanding)	408.5	3083.0	10.7	107.2	-110.6	-3841
37	CF Bartow DAP (#155)	408.5	3083.0	10.7	107.2	4.3	149
38	CF Bartow #7 SAP (#155)	408.5	3083.0	10.7	107.2	52.9	1837
39	CLM Chloride Metals (Closed)	361.8	3088.3	54.3	80.3	0.0	0
40	Conserve (Increment Expanding)	398.4	3084.2	18.9	100.1	-15.2	-528
41	Conserve No. 1 SAP (#076)	398.4	3084.2	18.9	100.1	42.0	1459
42	Farmland SAP 1, 2 (Increment Expanding)	409.5	3079.5	7.3	110.5	-54.6	-1895
43	Farmland SAP 3, 4 (No PSD #)	409.5	3079.5	7.3	110.5	67.2	2333
44	Farmland SAP 5 (#143)	409.5	3079.5	7.3	110.5	42.0	1457
45	IMC - Lonesome Mine Dry 1 (#088)	389.6	3067.9	25.4	109.5	18.4	639
46	IMC - Lonesome Mine Dry 2 (#088)	389.6	3067.9	25.4	109.5	21.2	735
47	Royster #1 (Increment Expanding)	406.7	3085.2	13.6	104.4	-257.6	-8947
48	Royster #2 (#106)	406.7	3085.2	13.6	104.4	35.7	1240
49,50	US Agri-Chem Fort Meade SAP 1, 2 (#107)	416.1	3068.6	5.6	123.2	126.0	4376

TABLE 6-8
EXISTING SOURCE EMISSIONS INVENTORY
CLASS I PSD SOURCES — SO_2

(Page 3 of 3)

No.	Name	UTM Coordinates		Distance from Polk County Site (km)	Nearest Class I Receptor (km)	Maximum Allowable SO_2 Emission Rates	
		East	North			(g/sec)	(TPY)
51	US Agrichem Fort Meade SAP X (Increment Expanding)	416.2	3068.7	5.5	123.1	-78.8	-2737
52	Seminole (WR Grace) Retired SAP (Increment Expanding)	409.7	3086.0	12.9	105.7	-216.0	-7502
53	Seminole (WR Grace) 2 46 16 (#157)	409.7	3086.0	12.9	105.7	73.6	2556
54	Seminole (WR Grace) 2 46 17 (#68)	409.5	3086.5	13.4	105.2	72.0	2501
55	Cargill (Gardinier) SAP 4, 5, 6 (Increment Expanding)	363.4	3082.4	51.5	86.4	-196.3	-6818
56,57	Cargill (Gardinier) SAP 7 Existing, Modification (Exp)	363.4	3082.4	51.5	86.4	-14.0	-485
58	AMAX (Mobil Big 4) (#1, #094)	394.8	3067.7	20.4	112.1	0.6	21
59	AMAX (Mobil Big 4) (#1, #094)	394.9	3069.8	19.8	110.4	16.4	568
60	Mobil - Nichols (#102)	398.3	3084.3	19.0	7.0	2.4	83
61	FDOC Boiler #3 * changed 1/3/92 * changed 1/8/92 (No PSD #)	382.2	3166.1	97.6	40.4	3.0	104
62	ER Jahna (Lime Dryer) (No PSD #)	386.7	3155.8	86.4	47.4	0.8	28
63	Oman Construction (Asphalt Plant) (No PSD #)	359.8	3164.9	106.0	19.5	2.1	73
64	Dris Paving (Asphalt Plant) (No PSD #)	340.6	3119.2	86.4	46.5	0.2	8
65	Overstreet Paving (Asphalt) (No PSD #)	355.9	3143.7	90.9	27.0	3.7	127
66,67	New Port Richey Hospital Boiler #1 * changed 1/3/92 (No PSD #)	331.2	3124.5	97.2	42.2	0.1	3
68,69	Hospital Corporation of America Boiler #1 (No PSD #)	333.4	3141.0	105.0	25.6	0.2	6
70	Couch Construction - Odessa (Asphalt) (No PSD #)	340.7	3119.5	86.5	46.2	7.3	252
71	Couch Construction - Zephyrhills (Asphalt) (No PSD #)	390.3	3129.4	60.4	61.8	3.5	123
72	Agrico Baseline (Increment Expanding)	407.5	3071.3	7.2	115.9	-75.6	-2626
73	Agrico Proposed (#179)	407.5	3071.3	7.2	115.9	113.5	3942
74	McKay Bay Refuse to Energy (#086)	360.0	3091.9	57.1	76.4	10.7	372

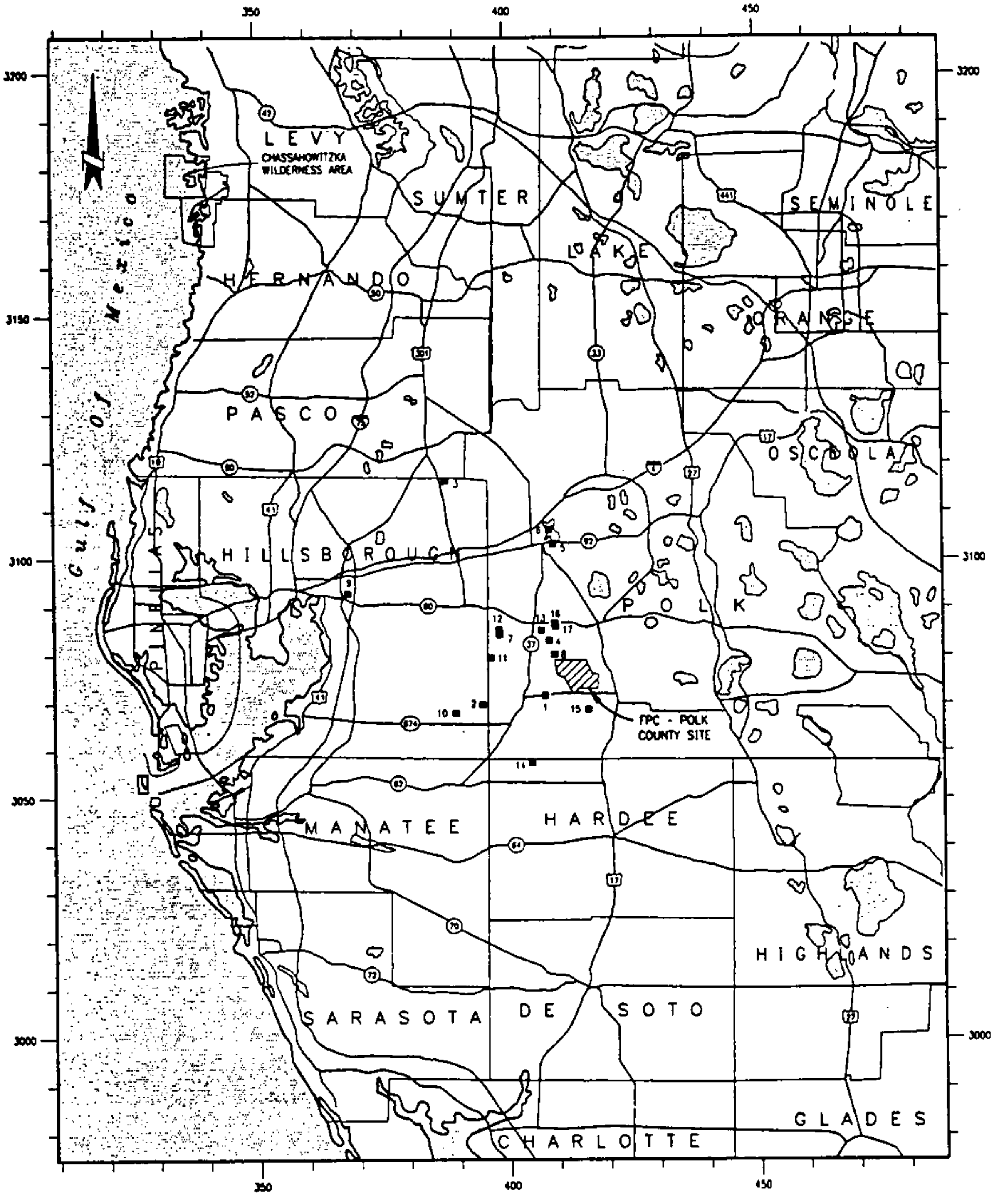
Source: Ebasco Environmental, 1992

TABLE 6-9
RECEPTOR GRID FOR PSD CLASS I AREA

Point	UTM Coordinates		Distance from Polk County Site *		
	East (km)	North (km)	ΔX (km)	ΔY (km)	Distance (km)
1	340.3	3,165.7	-74.0	91.82	117.9
2	340.3	3,167.7	-74.0	93.82	119.5
3	340.3	3,169.8	-74.0	95.92	121.1
4	340.7	3,171.9	-73.6	98.02	122.6
5	342.0	3,174.0	-72.3	100.12	123.5
6	343.0	3,176.2	-71.3	102.32	124.7
7	343.7	3,178.3	-70.6	104.42	126.0
8	342.4	3,180.6	-71.9	106.72	128.7
9	341.1	3,183.4	-73.2	109.52	131.7
10	339.0	3,183.4	-75.3	109.52	132.9
11	336.5	3,183.4	-77.8	109.52	134.3
12	334.0	3,183.4	-80.3	109.52	135.8
13	331.5	3,183.4	-82.8	109.52	137.3

* Location of "zero point" for Polk County Site is 414.300 km East; 3,073.880 km North

Note: The general location of the PSD Class I Chassahowitzka Wilderness Area is depicted in Figures 6-1 through 6-3.



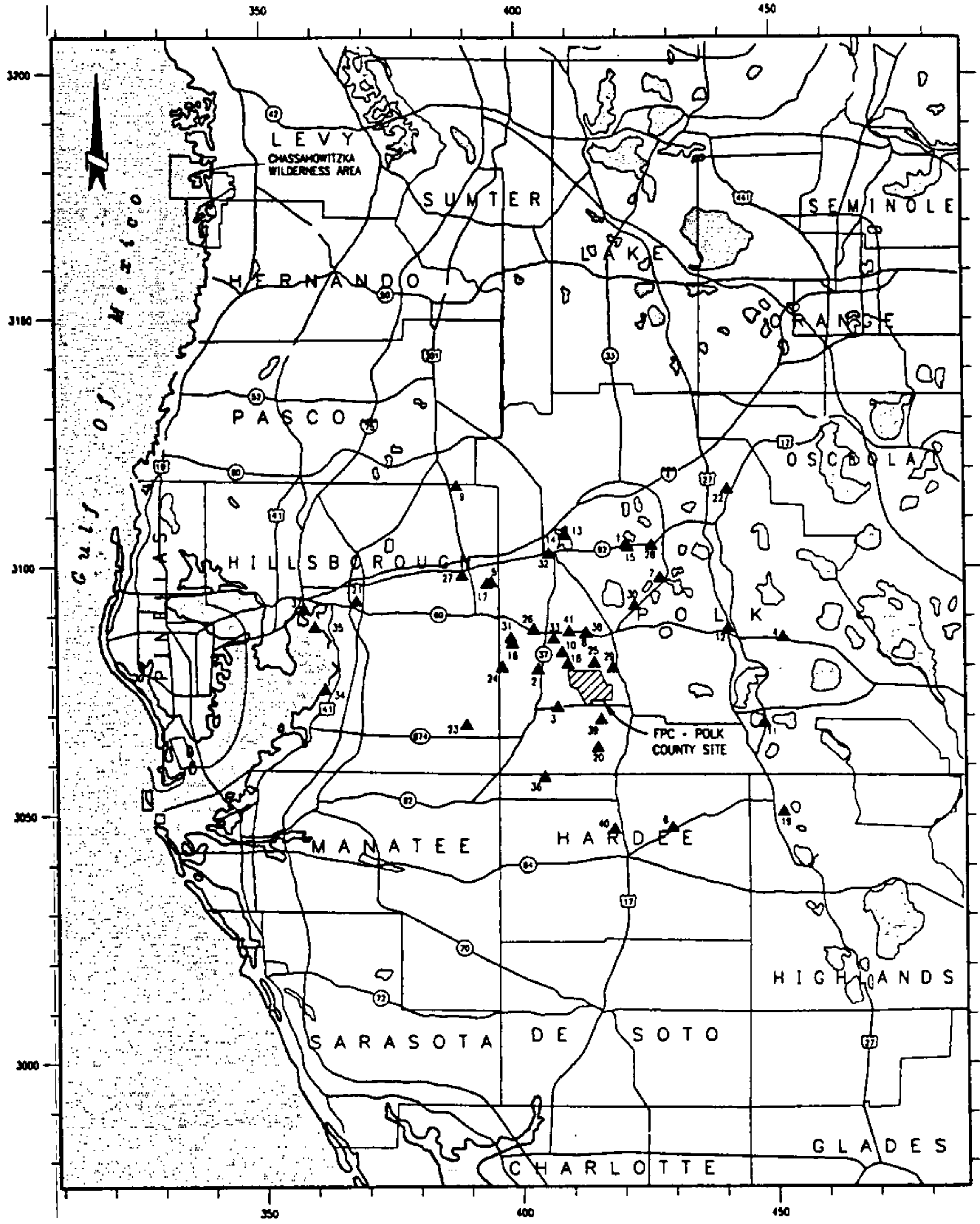
Note: #■ = Source Location Keyed to Table 6-6

Source: Ebasco Environmental, 1992

Florida Power
CORPORATION

Polk County Site

FIGURE 6-1
EXISTING SO_2 PSD CLASS II SOURCES



Note: #▲ = Source Location Keyed to Table 6-7

Source: Ebasco Environmental, 1992

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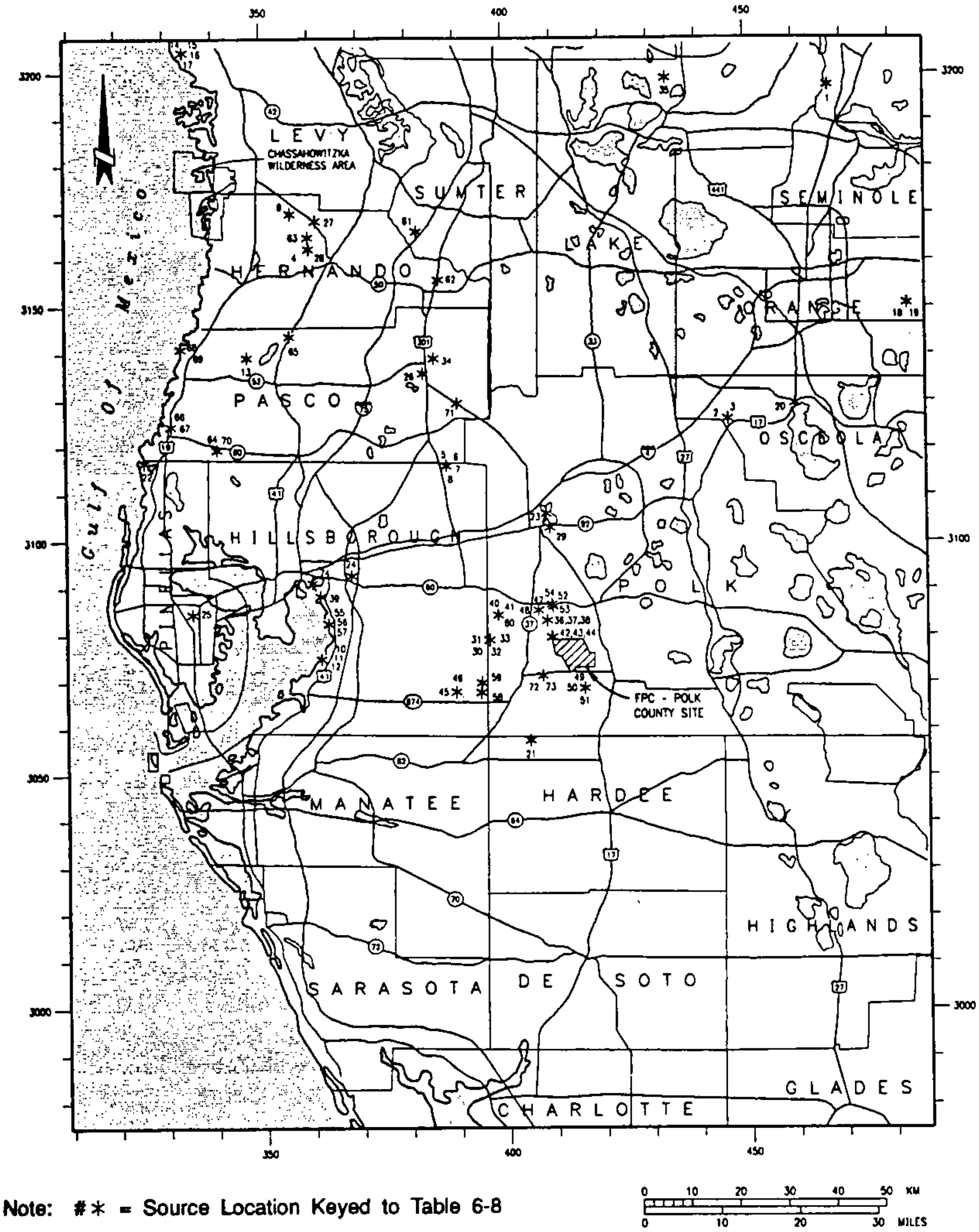
Polk County Site

FIGURE 6-2
EXISTING SO_2 AAQS SOURCES



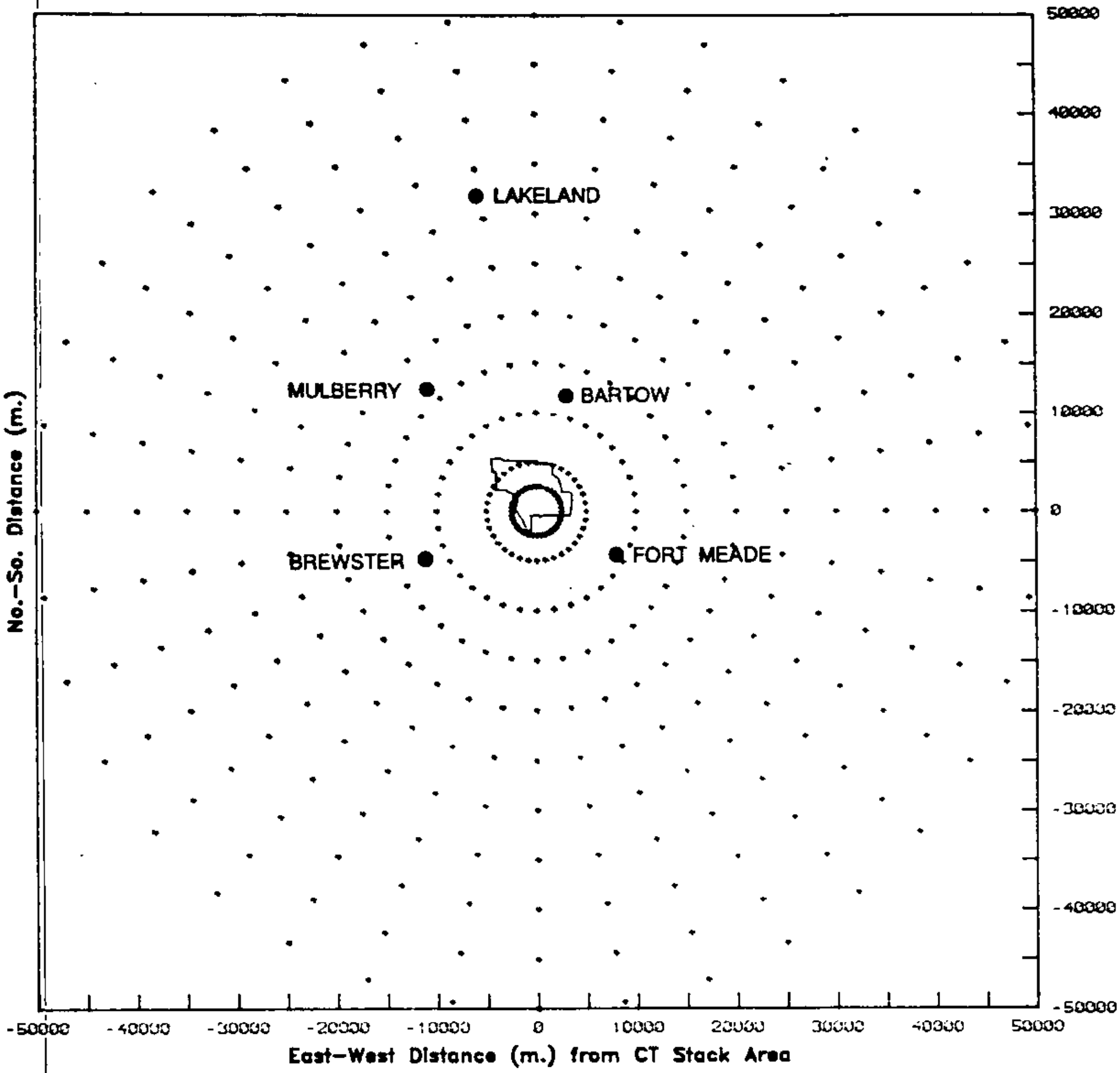
Note: #✳ = Source Location Keyed to Table 6-8

Source: Ebasco Environmental, 1992

Florida Power CORPORATION

Polk County Site

FIGURE 6-3
EXISTING PSD CLASS I SOURCES



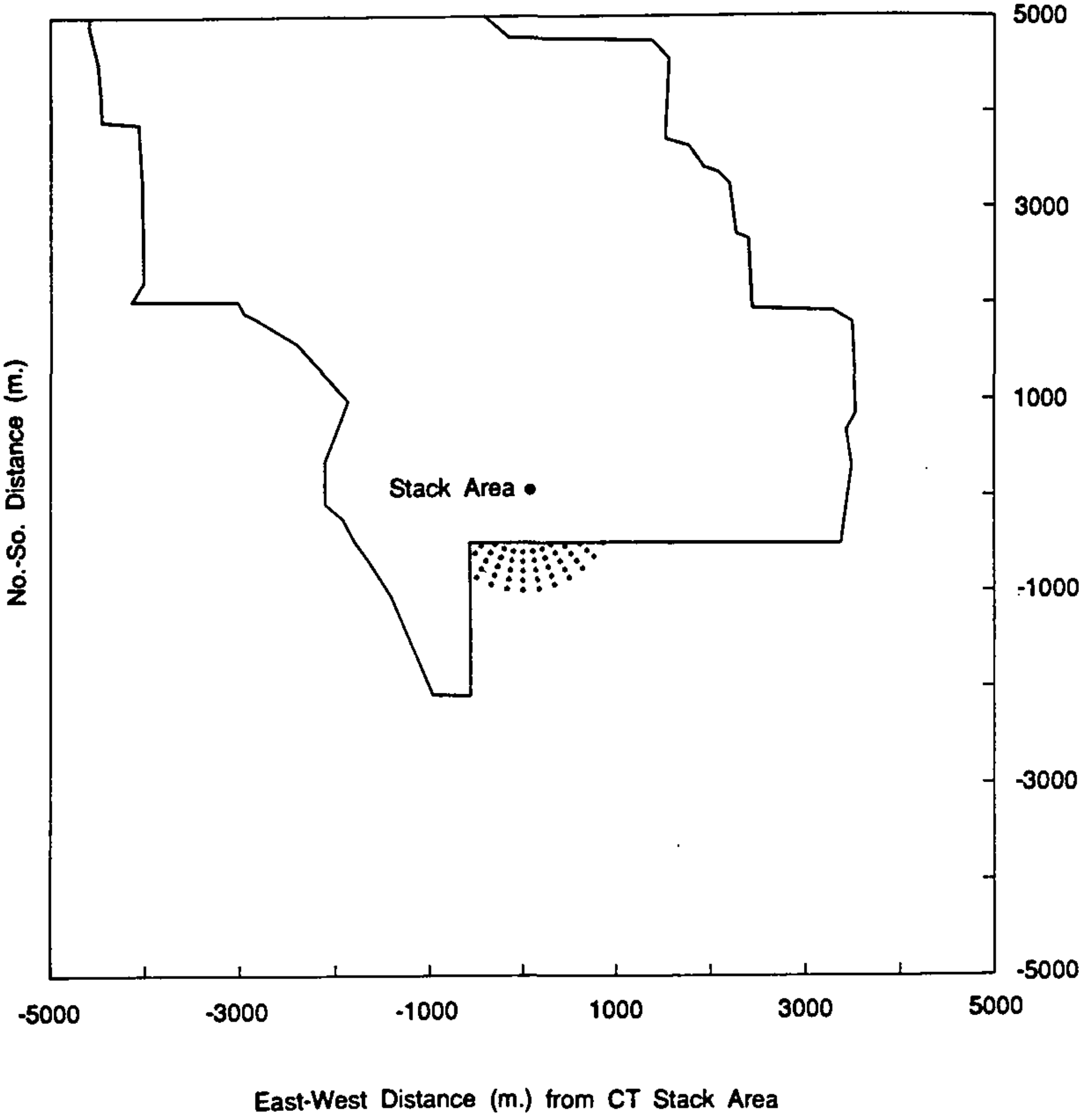
Source: Ebasco Environmental, 1992

Florida Power CORPORATION

Polk County Site

FIGURE 6-4
RECEPTOR GRID FOR SIGNIFICANT IMPACT AREA ANALYSIS

FPC Polk County Site



Source: Ebasco Environmental, 1992

Florida Power CORPORATION

Polk County Site

FIGURE 6-5
CLASS II/AAQS PHASE 1 RECEPTOR GRID

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0. It is organized into sections dealing with the predicted impacts of the proposed project by itself, predicted PSD increment consumption, predicted concentrations with respect to the AAQS, and predicted concentrations of air toxics versus FDER's draft "no threat" levels (FDER, 1992a). Finally, a brief conclusion is presented.

7.1 PROPOSED UNITS ONLY

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed CC facility was evaluated for both the primary fuel, natural gas, and the back-up fuel, fuel oil, to determine the worst-case impacts. Since the emissions on fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case. Based on previous experience in modelling CC units and the fact that CC units are generally operated at or near 100% load, it was assumed that 100% load would produce the maximum ground-level impacts. Therefore, no partial load cases were run for the CC units. However, since emissions and stack parameters from CC units are temperature dependant, modelling was conducted at temperatures of 40°F, 72°F, and 95°F to determine the worst-case operating scenarios. It was assumed for the purpose of this analysis that all four HRSG stacks were collocated. The results of this analysis for SO_2 are presented in Table 7-1.

Review of Table 7-1 indicates that maximum concentrations can be projected from any of the three ambient temperature scenarios depending upon averaging time and year of meteorology ultimately selected. Variations in concentrations are small between the scenarios. The 40°F case was selected as the "worst-case" scenario since it typically is for CC units. Parameters associated with this scenario were utilized in all further modelling. Subsequent runs for annual averages were made using the emissions and stack parameters associated with the 40°F case, but took into account the maximum of 500 hours per year of fuel oil firing and added 8,260 hours per year of emissions from natural gas firing.

Since the proposed auxiliary boiler and emergency diesel generator will not be operated simultaneously with the four CC units, except for brief periods of testing, the emissions from these sources have not been considered as a part of the worst-case operating scenario. The auxiliary boiler and emergency diesel generator have been modelled by themselves and their maximum off-site impacts are summarized in Section 7.1.3. These sources will be used during cold start conditions to help limit the emissions from the CC units in this mode. Thus, it is felt that ignoring the emissions from these facilities in the air quality impact analysis for the main units does not compromise the conservative, worst-case nature of the analysis.

7.1.2 Significant Impact Area Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine the significant impact area for each pollutant with an associated PSD increment or AAQS for the CC units. The significant impact area is defined in the EPA New Source Review Workshop Manual (EPA, 1990b) as the circular area whose radius is equal to the greatest distance from the proposed source to which modelling shows that the proposed source will have a significant impact, based upon EPA-defined significance values which are pollutant specific. The significant impact areas thus define the distances beyond which the impacts from the proposed source will be insignificant and need not be analyzed in conjunction with existing sources.

The results of the significant impact area analyses are presented in Table 7-2. For simplicity, all four CC unit stacks were assumed to be collocated for this analysis. The receptor grids used were as described in Section 6.5.1. As indicated in Table 7-2, the only pollutant for which there was a predicted significant impact off of plant property is SO_2. It has a significant impact area radius of 1.0 km. Thus, no further analysis is required for any of the other pollutants and the PSD increment consumption and AAQS compliance analysis focus on SO_2.

7.1.3 Summary of Impacts — Proposed Source Only

In addition to providing the significant impact areas, Table 7-2 also provides a summary of maximum predicted impacts due to the proposed source alone. However, the maximum short-term values are based on highest predicted concentrations and are not relevant for comparison with PSD increments and AAQSs. A summary of maximum off-site impacts using highest annual and highest, second-highest short-term concentrations for the proposed source alone is presented in Table 7-3.

As indicated in Table 7-3, maximum off-site impacts for all pollutants are very small in relation to PSD increments and AAQSs. The off-site impacts of SO_2 have been evaluated in more detail and the results are presented in the following sections.

Although the proposed auxiliary boiler and diesel generator are relatively small sources, they have been modelled using the emissions data and stack parameters provided in Section 6.0. Maximum off-site impacts due to these sources are indicated in Table 7-4. As indicated, predicted impacts are small in comparison with PSD increments and AAQSs.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

As indicated in Section 6.5.1, no screening or coarse grid analysis was performed due to the small area of significant impact for SO_2. Therefore, the fine receptor grid depicted in Figure 6-5 was used in the analysis together with all five years of meteorological data. In addition to the emissions from the proposed source listed in Table 6-3, the emissions from the other PSD increment consuming and increment expanding sources identified in Table 6-6 were included in the modelling. The results are presented in Table 7-5. As indicated in the Table, the maximum predicted Class II PSD increment consumption in the vicinity of the proposed project is well within the allowable values for all averaging times.

7.2.2 Class I Area

Although the proposed project will be located approximately 118 km from the nearest boundary of the nearest Class I PSD area, the Chassahowitzka Wilderness Area, the impacts of the proposed project were modelled. The PSD regulations and guidelines do not contain specific significance values for use in determining whether a detailed analysis of Class I PSD increment consumption is warranted. EPA is only now in the process of developing such values. However, in the interim, EPA has indicated that significance values developed by the Virginia Department of Air Pollution Control represent "a reasonable interpretation of the relevant statutory and regulatory requirements..." and can be used as interim guidance by each state (EPA, 1991a). The Virginia significance values are based upon the application of the minimum Class II significance values divided by the Class II increment ratio to the Class I increments. Since FDER is still considering its options in this regard, the interim EPA values are being used in this application as a basis for determining the significance of the project's predicted impacts on the Class I area with respect to PSD increment consumption.

A summary of the project's predicted impact on the Class I area receptors (see Table 6-8) is presented in Table 7-6. As indicated, the predicted maximum impacts are below the significance values for NO_X and TSP and no further analysis is warranted for those pollutants. For SO_2, the maximum project impacts are above the short-term significance values. Therefore an analysis was conducted with the ISCST model of Class I area impacts using the entire emission inventory contained in Table 6-8 in addition to the proposed project. The results of that analysis indicated that the short-term PSD Class I increments are predicted to be violated on several days per year at many of the Class I area receptor points. These predicted violations are caused by a combination of sources which impact different receptors under different meteorological conditions. However, the modelling indicated that for the specific receptors and time periods with predicted violations the proposed project's impacts are less than the PSD Class I significance values. Thus, the proposed project will not cause nor contribute to any of the predicted violations of the Class I PSD increments and can be permitted.

7.3 AAQS ANALYSIS

The AAQS analysis consisted of modelling the impacts of the proposed source together with background concentrations to determine if the totals will be within the allowable NAAQS and FAAQS. Background concentrations consist of a modelled component (modelled impacts of significant existing sources) and a monitored component (based upon the concentrations presented in Table 5-4). The existing sources which were included in the modelling were identified in Table 6-7. The results of the analysis are summarized in Table 7-7. As indicated in the table, maximum SO_2 concentrations for all averaging periods will be below the allowable AAQS.

7.4 AIR TOXICS ANALYSIS

The air toxics analysis consisted of modelling the proposed source at a unit emission rate of one (1) gram per second to determine maximum predicted 1-hour, 3-hour, 8-hour, 24-hour, and annual concentrations outside the proposed facility's boundary. These predicted maximum concentrations are presented in Table 7-8. Next, maximum predicted concentrations for each of the trace metals and speciated VOCs were calculated based on the ratio of the estimated emission rate to one gram per second. Finally, the predicted trace metal and speciated VOC concentrations were compared to the FDER's draft "no threat" levels (FDER, 1992a). As indicated in Table 7-9, all predicted impacts of trace metals and speciated VOCs are below the FDER's draft "no threat" levels.

7.5 CONCLUSIONS

As indicated by the review and analysis in the previous sections, the proposed project will not cause or contribute to violations of the allowable PSD increments or AAQS. Furthermore, the project impacts will be below the FDER draft "no threat" levels for air toxics.

TABLE 7-1
WORST-CASE TEMPERATURE ANALYSIS RESULTS

Averaging Time	Year	Maximum SO$_2$ Concentration (μg/m^3)		
		40°F	72°F	95°F
3-Hour	1982	15.66	14.30	13.51
	1983	9.01	13.69	13.39
	1984	16.10	15.66	15.41
	1985	17.23	16.06	15.35
	1986	8.84	8.41	8.15
24-Hour	1982	2.15	2.09	2.07
	1983	2.00	2.48	2.55
	1984	6.25	6.02	5.93
	1985	2.51	2.97	2.98
	1986	2.06	2.07	2.11
Annual	1982	0.040	0.042	0.045
	1983	0.037	0.049	0.051
	1984	0.050	0.052	0.056
	1985	0.043	0.047	0.048
	1986	0.043	0.044	0.047

(1) Annual values have not been adjusted for limited fuel oil usages.

Source: Ebasco Environmental, 1992

TABLE 7-2
SUMMARY OF SIGNIFICANT IMPACT AREA CONCENTRATIONS

Pollutant	Averaging Period	Maximum (1) Predicted Concentration ($\mu g/m^3$)	Location (2) X (m)	Location (2) Y (m)	Year	Significance Level ($\mu g/m^3$)	Distance to Significance (km)	Off-site Significant Impact (Yes/No)
Carbon Monoxide	1-Hour	47.1	866	-500	1985	2,000	None	No
	8-Hour	11.7	766	-643	1984	500	None	No
Nitrogen Dioxide	Annual	0.38	3600	0	1986	1	None	No
Sulfur Dioxide	3-Hour	17.3	-2145	-1800	1984	25	None	No
	24-Hour	6.25	613	-514	1984	5	1.0	Yes
	Annual	0.02	3600	0	1986	1	None	No
Particulate Matter (PM_{10} or TSP) (3)	24-Hour	1.08	613	-514	1984	5	None	No
	Annual	0.03	3600	0	1986	1	None	No
Beryllium	24-Hour	0.00025	613	-514	1984	N/A	N/A	N/A
Sulfuric Acid	24-Hour	0.61	613	-514	1984	N/A	N/A	N/A
Benzene	24-Hour	0.0066	613	-514	1984	N/A	N/A	N/A
Inorganic Arsenic	24-Hour	0.00045	613	-514	1984	N/A	N/A	N/A

(1) Short-term values are highest rather than highest, second-highest values for this analysis.
(2) With respect to zero point of 414.30 km E; 3,073.88 km N.
(3) The allowable PSD increment is evaluated for TSP whereas the AAQS compliance is evaluated for PM_{10}. As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

Source: Ebasco Environmental, 1992

TABLE 7-3
SUMMARY OF MAXIMUM OFF-SITE IMPACT CONCENTRATIONS

Pollutant	Averaging Period	Maximum [(1)] Predicted Concentration ($\mu g/m^3$)	Location [(2)]		Year	PSD Increment ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
			X (m)	Y (m)			
Carbon Monoxide	1-Hour 8-Hour	27.3 7.7	919 615	-771 -514	1982 1984	N/A N/A	40,000 10,000
Nitrogen Dioxide	Annual	0.38	3600	0	1986	25	100
Sulfur Dioxide	3-Hour 24-Hour Annual	13.45 3.08 0.02	613 866 3600	-514 -500 0	1984 1984 1986	512 91 20	1,300 260 60
Particulate Matter (PM_{10} or TSP) (3)	24-Hour Annual	0.53 0.03	613 3600	-514 0	1984 1986	37 19	150 50
Beryllium	24-Hour	0.00028	613	-514	1984	N/A	N/A
Sulfuric Acid	24-Hour	0.63	613	-514	1984	N/A	N/A
Benzene	24-Hour	0.0068	613	-514	1984	N/A	N/A
Inorganic Arsenic	24-Hour	0.00048	613	-514	1984	N/A	N/A

(1) Short-term values are highest, second-highest values for this analysis except for beryllium, benzene, inorganic arsenic, and sulfuric acid.

(2) With respect to zero point of 414.30 km E; 3,073.88 km N.

(3) The allowable PSD increment is evaluated for TSP whereas the AAQS compliance is evaluated for PM_{10}. As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

Source: Ebasco Environmental, 1992

TABLE 7-4
MAXIMUM OFF-SITE IMPACT CONCENTRATIONS OF AUXILIARY BOILER AND DIESEL GENERATOR

Pollutant	Averaging Period	Maximum (1) Predicted Concentration ($\mu g/m^3$)	Location (2) X (m)	Location (2) Y (m)	Year	PSD Increment ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
Carbon Monoxide	1-Hour 8-Hour	240.4 72.5	-104 -450	-591 -536	1985 1986	N/A N/A	40,000 10,000
Nitrogen Dioxide	Annual	0.12	-450	-563	1984	25	100
Sulfur Dioxide	3-Hour 24-Hour Annual	23.2 7.0 0.007	-450 -450 -450	-536 -536 -536	1983 1986 1984	512 91 20	1,300 260 60
Particulate Matter (PM_{10} or TSP) (3)	24-Hour Annual	6.1 0.006	-450 -450	-536 -536	1986 1982	37 19	150 50
Beryllium	24-Hour	0.00041	-450	-536	1986	N/A	N/A
Sulfuric Acid	24-Hour	0.28	-450	-536	1986	N/A	N/A
Benzene	24-Hour	0.002	-450	-536	1986	N/A	N/A
Inorganic Arsenic	24-Hour	0.00066	-450	-536	1986	N/A	N/A

(1) Short-term values are highest, second-highest values for this analysis except for beryllium, benzene, and inorganic arsenic.

(2) With respect to zero point of 414.30 km E; 3,073.88 km N.

(3) The allowable PSD increment is evaluated for TSP whereas the AAQS compliance is evaluated for PM_{10}. As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable
Source: Ebasco Environmental, 1992

TABLE 7-5
MAXIMUM PREDICTED SO_2 IMPACTS(1) VERSUS CLASS II PSD INCREMENTS

Averaging Period	Maximum (2) Concentration ($\mu g/m^3$)	Receptor Location (3)		Period			PSD Class II Increment ($\mu g/m^3$)
		X (m)	Y (m)	Julian Day	Ending Hour	Year	
3-Hour	103.5	689	-579	346	6	1985	512
24-Hour	25.27	-500	-866	357	N/A	1985	91
Annual	3.10	-500	-866	N/A	N/A	1986	20

(1) Proposed and existing PSD Sources.
(2) Maximum short-term concentrations are highest, second-highest values.
(3) With respect to zero point of 414.30 km E; 3,073.88 km N.

N/A - Not applicable

Source: Ebasco Environmental, 1992

TABLE 7-6
MAXIMUM PREDICTED PROJECT IMPACTS VERSUS CLASS I PSD SIGNIFICANCE VALUES

Pollutant	Averaging Period	Maximum [1] Concentration ($\mu g/m^3$)	Receptor Location [2]		Period			PSD Class I Significance Value[3] ($\mu g/m^3$)	Project Impact Significance (Yes/No)
			X (m)	Y (m)	Julian Day	Ending Hour	Year		
Nitrogen Dioxide	Annual	0.031	-73,870	91,820	N/A	N/A	1982	0.1	No
Particulate Matter (PM_{10} or TSP)	24-Hour	0.090	-73,470	98,020	70	N/A	1986	1.35	No
	Annual	0.003	-73,870	91,820	N/A	N/A	1982	0.27	No
Sulfur Dioxide	3-Hour	3.45	-73,870	93,820	210	1	1982	1.23	Yes
	24-Hour	0.53	-73,470	98,020	70	N/A	1986	0.275	Yes
	Annual	0.002	-73,870	91,820	N/A	N/A	1982	0.1	No

[1] Maximum short-term periods less than annual concentrations are highest, second-highest values.

[2] With respect to zero point of 414.30 km E; 3,073.88 km N.

[3] Values suggested by EPA (1991)

Source: Ebasco Environmental, 1992

TABLE 7-7
MAXIMUM PREDICTED SO_2 CONCENTRATIONS VERSUS AAQS

Averaging Time	Maximum Concentrations [1]				Receptor Location [2]		Period			AAQS	
	FPC (μg/m³)	Existing Sources (μg/m³)	Monitored Value (μg/m³)	Total (μg/m³)	X (m)	Y (m)	Julian Date	Ending Hour	Year	FAAQS (μg/m³)	NAAQS (μg/m³)
3-Hour	0.0	256.7	78	334.7	-500	-866	135	9	1985	1,300	1,300
24-Hour	0.1	82.7	34	116.8	174	-985	198	N/A	1983	260	365
Annual	0.01	18.0	5	23.0	-514	613	N/A	N/A	1985	60	80

N/A - Not Applicable

[1] Maximum short-term concentrations are highest, second-highest values.

[2] With respect to zero point of 414.30 km E; 3,073.88 km N.

Source: Ebasco Environmental, 1992

TABLE 7-8
NORMALIZED MAXIMUM OFF-SITE IMPACTS

Averaging Period	**Location**		**Year**	**Maximum Predicted Concentration*** ($\mu g/m^3$)
	X (m)	**Y (m)**		
1-Hour	766	-643	1984	0.972
3-Hour	-2145	-1800	1984	0.35
8-Hour	766	-643	1984	0.24
24-Hour	613	-514	1984	0.126
Annual	3600	0	1984	0.0083

* Maximum predicted concentration based on four (4) CC units collocated and emitting one (1) gram per second of pollutant and highest concentration versus highest, second-highest concentration.

Source: Ebasco Environmental, 1992

TABLE 7-9
AIR TOXICS ANALYSIS (1)
PHASE I — 940 MW

(PAGE 1 OF 2)

Pollutant	Emission (2) (g/s)	FDER NTLs ($\mu g/m^3$)			Maximum Predicted Concentration ($\mu g/m^3$)			Acceptable
		8-Hour	24-Hour	Annual	8-Hour	24-Hour	Annual(6)	
Trace Metals (3)								
Antimony *	0.020	5	1.2	0.30	0.004815	0.002528	0.0000095	Yes
Arsenic *	0.0038	2	0.48	0.00023	0.000915	0.000480	0.0000018	Yes
Barium	0.018	5	1.2	50	0.004248	0.002230	0.0000083	Yes
Beryllium *	0.0023	0.02	0.0048	0.00042	0.000544	0.000285	0.0000011	Yes
Boron (5)	0.059	100	24	N/A	0.014185	0.007447	0.000028	Yes
Cadmium *	0.0095	0.5	0.12	0.00056	0.002287	0.001201	0.0000045	Yes
Calcium (5)	0.68	100	24	N/A	0.162768	0.085453	0.000321	Yes
Chromium *	0.043	5	1.2	0.0020	0.010350	0.005433	0.000020	Yes
Cobalt *	0.0082	0.5	0.12	N/A	0.001974	0.001036	0.0000039	Yes
Copper	0.254	10	2.4	N/A	0.061010	0.032030	0.00012	Yes
Lead	0.0081	N/A	N/A	N/A	0.001939	0.001018	0.0000038	N/A
Magnesium (5)	0.21	100	24	N/A	0.050551	0.026539	0.0001	Yes
Manganese *	0.13	50	12	0.40	0.003050	0.001601	0.000006	Yes
Mercury *	0.0027	0.5	0.12	0.30	0.000653	0.000343	0.0000013	Yes
Nickel *	0.15	1	0.24	N/A	0.037042	0.019447	0.000073	Yes
Selenium *	0.021	2	0.48	N/A	0.000512	0.000268	0.000001	Yes
Vanadium (as V_2O_5)	0.063	.5	0.12	20	0.015165	0.007961	0.00003	Yes
Zinc	0.62	50	24	N/A	0.255101	0.133928	0.0005	Yes

TABLE 7-9
AIR TOXICS ANALYSIS (1)
PHASE I — 940 MW

(PAGE 2 OF 2)

Pollutant	Emission (2) (g/s)	FDER NTLs (μg/m³)			Maximum Predicted Concentration (μg/m³)			Acceptable
		8-Hour	24-Hour	Annual	8-Hour	24-Hour	Annual(5)	
Volatile Organic Compounds (4)								
Benzene *	0.054	30	7.2	0.12	0.013	0.0065	0.00045	Yes
Formaldehyde *	0.17	12	2.88	0.077	0.042	0.022	0.0014	Yes

(1) Analysis is for the four (4) 235 MW CC units only.
(2) Emission estimates obtained from EPA, 1988, and EPA, 1989.
(3) Trace metal emissions based on four (4) 235 MW CC units fired on fuel oil.
(4) Volatile organic compound emissions based on four (4) 235 MW CC units fired on natural gas.
(5) Based on natural gas firing for 8260 hrs/yr and fuel oil firing for 500 hrs/yr.

* Listed pollutant under Title III of the CAA Amendments of 1990

NTL = "No Threat" Level (FDER, 1992, Draft Air Toxics Guidelines)

N/A = Not Applicable

Source: Ebasco Environmental, 1992

8.0 ADDITIONAL IMPACTS ANALYSIS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 2-5, those pollutants include CO, NO_X, SO_2, PM, VOC (O_3), beryllium, sulfuric acid mist, benzene, and inorganic arsenic. The additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of project impacts on visibility. These analyses are included in this section of the PSD application.

The focus of the visibility, vegetation, and soils portions of the additional impacts analysis section of a PSD application is typically on any nearby Class I areas. As has been demonstrated in Section 7.0 of this application, the proposed project will neither cause nor contribute to violations of the Class I PSD increments (nor the AAQS) at the Chassahowitzka Wilderness Area, located from 118 to 135 km from the proposed source. In spite of this distance, FPC has agreed to provide an impact on air quality-related values (AQRV) analysis as a part of the application. The U.S. Fish and Wildlife Service (FWS) has identified some vegetation, wildlife, and visibility concerns for the Chassahowitzka (FWS, 1992). Therefore, the additional impacts analysis section has been broadened to cover these AQRV issues as well as the traditional issues. Furthermore, consideration is given to a wide range of pollutants that will be emitted by the project in small quantities rather than restricting the analyses to those pollutants subject to PSD review.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis. The analysis of socioeconomic effects presented in Chapter 7.0 of the Site Certification Application serves as the basis for this growth analysis.

Up to 500 people will be employed at the Polk County Site during any one year of the six-year construction phase for the first 940 MW, and approximately 50 permanent jobs will be filled to operate the completed facility. It is anticipated that the majority of the construction workers will commute from their current residences, whereas approximately 55 to 60 percent of the 50 operational employees will migrate into the Polk County area. Based on the average household size of 2.53 persons, a total of 76 persons (workers and their families) are predicted to move into the area as a result of the first 940 MW of the new FPC Polk County site. This will account for less than one percent of the projected increase of 141,318 persons for Polk County between 1990 and 2000 (Moore/Bowers, 1992).

A considerable amount of residential and commercial development will be associated with this population influx (construction of new homes and rental property; establishment of new businesses to provide goods and services). However, the permanent, nonmobile source emissions and impacts of this development will likely be small and have impacts on different areas than those affected by emissions of the new CC facility at the Polk County Site.

Development of industries supporting the new CC facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region. Further processing, such as water treatment, will be accomplished entirely onsite.

Electricity sales, on the other hand, will be spread out over a large region as part of FPC's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be residential growth associated with the FPC project, but there is little potential for new industrial development nearby as a result of the new facility. Although it is not possible to reliably quantify the emissions and impacts resulting from the new development, they are expected to be small and well-distributed throughout the area. Any large industries proposed will be subject to the most stringent requirements associated with locating a PSD facility near another existing PSD source.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

The vegetation and soils components of the additional impacts analysis has been expanded to constitute an air quality-related values (AQRVs) analysis to assess the potential risk to AQRVs of the Chassahowitzka Wilderness Area due to the development of the proposed project. Potential air quality impacts of the proposed project were predicted at the PSD Class I Area portion of the Chassahowitzka National Wildlife Refuge (NWR). The U.S. Department of the Interior (National Park Service) in 1978 administratively defined AQRVs to be:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
>
> Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

Except for visibility, AQRVs have not been specifically defined by the Fish and Wildlife Service for the Chassahowitzka NWR. However, soil, flora, fauna, cultural resources, geological features, water, and climate often have been identified by land managers as AQRVs to be addressed in these types of analyses. Since specific AQRVs have not been identified for the Chassahowitzka NWR, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found on the Chassahowitzka NWR.

Vegetation type AQRVs and their representative species types have been defined as:

Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass

Marsh Islands - cabbage palm and eastern red cedar

Estuarine Habitat - black needlerush, salt marsh cordgrass, wax myrtle

Hardwood Swamp - red maple, red bay, sweet bay and cabbage palm

Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle and saw palmetto

Mangrove Swamp - red, white and black mangrove

Wildlife AQRVs included: endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles and mammals.

A screening approach was used which compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWR with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the NWR. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It was recognized that effect threshold information is not available for all species found in the Chassahowitzka NWR, although studies have been performed on a few of the common species and on other similar species which can be used as models. In conducting the assessment, both direct (fumigation) and indirect (soil accumulation/uptake) exposures were considered for flora, and direct exposure (inhalation) was considered for wildlife. Maximum concentrations and depositions were predicted using the ISCST model and five years of meteorological data as described in Sections 6.0 and 7.0.

Since background air quality monitoring data are not available for the NWR, background values for the criteria pollutants were estimated (Table 8-1) based on monitoring data from regional air quality monitoring locations (a conservative approach since the monitors are either near point sources or in more urban areas). The SO_2 and TSP data were averages from two Crystal River Power Plant monitors (FPC, 1992a). The O_3 data are from Gainesville for 1987 and 1988 (ESE, 1988, 1989). The NO_2 data are an average from Gainesville (ESE, 1987, 1988). Values for CO (annual) were estimated based on short-term monitoring data for the Tampa area (FDER, 1991) and the lead values were from Tampa (FDER, 1991).

8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

The effects of contaminants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants. The maximum predicted impacts due to the proposed project for the 1-hour, 3-hour, 8-hour, 24-hour, and annual averaging periods and estimated annual average background concentrations are presented in Table 8-1.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms, while chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

8.3.1.1 Nitrogen Dioxide

Nitrogen dioxide (NO_2) is the air contaminant with the highest predicted emission level for the proposed project. Acute NO_2 injury symptoms are manifest as water-soaked lesions, which first appear on the upper surface, followed by rapid tissue collapse. Low-concentration, long-term exposures as frequently encountered in polluted atmospheres often do not induce the lesions associated with acute exposures but may still result in some growth suppression.

The maximum ground-level NO_2 concentration (annual average) predicted to occur in the NWR during the operation of the proposed project is 10.031 $\mu g/m^3$ (10 $\mu g/m^3$ estimated background plus 0.031 $\mu g/m^3$ project impact). This maximum concentration is 2.1x10-2 the estimated threshold values (Tables 8-2 and 8-3), assuming a value of 470 $\mu g/m^3$ as the threshold value for an annual average. The 1-, 3-, 8-hour, and 24-hour predicted NO_2 project impacts at the point of maximum impact in the NWR are 17.6, 9.9, 4.5 and 1.43 $\mu g/m^3$, respectively. Even when combined with annual average background concentration of 10 $\mu g/m^3$, these values are approximately $5.8x10^{-2}$ to $2.4x10^{-2}$ of the levels reported in the literature (Table 8-3) as resulting in minimal effects on relatively sensitive species (470 $\mu g/m^3$). The annual estimated NO_2 concentration at the point of maximum impact in the NWR (10.031 $\mu g/m^3$) is 2.1x10-2 of the levels that are reported to cause minimal yield loss and chlorosis in plants.

8.3.1.2 Sulfur Dioxide

The predicted maximum ground level 1-hour, 3-hour, 8-hour, 24-hour and annual mean concentrations in the NWR resulting from operation of the proposed project, are 5.1, 2.9, 1.3, 0.5, and 0.0022 $\mu g/m^3$, respectively (Table 8-1). Combining the predicted maximum ground level concentration with an annual SO_2 value of 3 $\mu g/m^3$ results in total concentrations that are $6.2x10^{-3}$, $1.5x10^{-2}$, and $3.3x10^{-2}$ of the 1-hour, 3-hour, and 8-hour injury threshold concentrations (1,300, 400, and 131 $\mu g/m^3$) for sensitive vegetation as reported in the literature (Table 8-4). The annual average of 3.0022 $\mu g/m^3$ (3 $\mu g/m^3$ estimated background plus 0.0022 $\mu g/m^3$ project impact) is $2.5x10^{-2}$ of the value reported as resulting in no foliar injury on maples during a growing season (Table 8-5). The 1-hour and 3-hour predicted concentrations in the NWR (8.1 and 5.9 $\mu g/m^3$) are $3.1x10^{-3}$ and $3.7x10^{-3}$ of the 1-hour and 3-hour SO_2 concentrations used to identify southern pines as sensitive to SO_2. Under these predicted ambient concentrations, no injury symptoms could be expected in the areas of maximum concentration in the NWR. The potential for physiological or chronic injury occurring can not be predicted with certainty. The predicted maximum annual increment from operation of the proposed project is 0.0022 $\mu g/m^3$. Most evidence in the literature suggests that levels around 118 $\mu g/m^3$ may be responsible for physiological or chronic injury. Since there is a 115 $\mu g/m^3$ difference between the predicted ambient concentration (3.0022 $\mu g/m^3$) and the reported threshold concentration, the probability of physiological or chronic injury is low.

Sulfur can also be added to soil through washout of atmospheric SO_2 by precipitation. In a study in Minnesota, annual sulfur additions from atmospheric SO_2 washout were found to range from 100 lbs/acre in urban areas to 5 lbs/acre in rural areas. In southern states, the annual average is about 5 lbs/acre (Kamprath, 1972). In some cases, the amount of sulfur deposition is sufficient to meet crop requirements, although in rural areas, the amount of sulfur deposition is sufficient to meet only about 20-30 percent of crop needs.

8.3.1.3 Ozone

Ozone (O_3) will not be a direct by-product from the combustion of fuel at the proposed project, but instead results from a complex photochemical reaction involving nitrogen oxides and hydrocarbons. Ozone formation is not well understood, although it is generally believed that it is a phenomenon occurring at long downwind distances from, but not in the immediate vicinity of a source, such as the proposed project. This is attributed to the kinetics and time-dependent nature of the necessary photochemical reaction.

It is difficult to predict what effect the proposed project emissions will have on ambient ozone concentrations at local or regional scales. It is anticipated that any potential increase in ozone concentration would be more detectable on a regional scale as opposed to a local one. The estimated annual average background ozone concentration in the area is 55 $\mu g/m^3$ based on monitoring by FDER and the Florida Acid Deposition Study (Environmental Science & Engineering; 1988, 1989). This value is below the range of threshold concentrations reported to be injurious to vegetation sensitive to O_3 (Tables 8-6 and 8-7).

Since it is not possible to model how the emissions from the proposed project will affect the ambient O_3 concentration in the NWR, it was assumed for purposes of this analysis that the levels potentially occurring in the NWR would be equal to the ambient concentrations monitored at Gainesville, FL (ESE, 1988-89). This approach is based on the assumption that the levels monitored at Gainesville are representative of O_3 concentrations in rural locations as influenced by emissions from urban areas, and that this would be similar to the potential influence that the proposed project and all other sources would have on the NWR. The average O_3 concentration monitored at Gainesville is 55 $\mu g/m^3$ (28 ppb) for an annual average, and the second highest 1-hour concentration was 176 $\mu g/m^3$ (90 ppb). These values fall within the levels that would allow permitting in the absence of evidence of acutal or predicted effects to the resource. Currently, there are no studies indicating actual harm to the resource. Given the location and distance of the proposed project and its relatively small contribution of O_3 precursors to regional totals, it can reasonably be predicted that the addition of the proposed project would not cause any harm to the resource.

8.3.1.4 Particulates

The maximum predicted concentration of particulates (in the form of TSP) from the proposed project is 0.0033 $\mu g/m^3$ for annual average. The existing background concentration in the vicinity of the proposed project based on data from the FPC Crystal River monitoring program, is 29 $\mu g/m^3$ for an annual average. Combined with existing background, the predicted maximum concentrations will be 29.0033 $\mu g/m^3$ on an annual basis. By comparing predicted concentrations with the few injury threshold values reported in the literature (Darley, 1966; Krause and Kaiser, 1977), no potential effects on vegetation are predicted, because this concentration is below the values reported to adversely affect plants.

8.3.1.5 Carbon Monoxide

Concentrations of carbon monoxide even in polluted atmospheres are not detrimental to vegetation (EPA, 1976). Carbon monoxide has not been found to produce detrimental effects on plants at concentrations below 100 ppm (114,500 $\mu g/m^3$) for exposures from one to three weeks (EPA, 1976). Existing background concentrations (1700 $\mu g/m^3$) plus contribution of the proposed project (0.03 $\mu g/m^3$) would be 1.5×10^{-2} of values reported to cause detrimental effects.

8.3.1.6 Synergistic Responses

SO_2 - NO_2 Synergism

It has been demonstrated in the literature (Tingey et al., 1971) that NO_2 in combination with certain concentrations of SO_2 can result in synergistic plant responses (i.e., leaf injury is observed at concentrations below the injury thresholds for each of these air contaminants in isolation). Maximum annual SO_2 and NO_2 concentrations are predicted to be 3.0022 and 10.031 $\mu g/m^3$, respectively in the NWR. Considered in isolation, the maximum predicted annual concentrations for both SO_2 and NO_2 are well below the threshold level for sensitive vegetation. Maximum short-term concentrations are in the range of concentrations where SO_2-NO_2 synergistic effects have been reported to occur for certain species, none of which occur on or adjacent to the NWR (Table 8-8).

There is not significant evidence in the literature to either support or negate the possibility that synergistic effects may occur within the NWR as a result of the predicted annual ambient concentrations of SO_2 and NO_2. However, the predicted SO_2 and NO_2 concentrations (annual average) appear to be much less than that resulting in a synergistic response over longer exposure periods. Tingey et al. (1971) report that the concentrations of SO_2 and NO_2 found to cause injury in their studies were similar to those found in urban areas and may result in reduced yields of crops grown under field conditions. However, it should be noted that synergistic effects from SO_2-NO_2 have rarely been observed in the field. In addition, data on the effects on vegetation due to mixtures of SO_2 and NO_2 are limited and the general consensus of most investigators is that more research is required before SO_2-NO_2 synergism is completely understood and potential effects predicted for field situations with any degree of certainty.

SO_2 - O_3 Synergism

Tingey et al. (1973a and 1973b) have observed that mixtures of SO_2 and O_3 at concentrations typically found in urban areas have resulted in synergistic or additive plant responses (i.e., plant leaf injury is observed at concentrations below the injury threshold levels for each of these air contaminants in isolation). There are no generalized injury threshold concentrations of SO_2-O_3 (in mixture) listed in the literature that would apply specifically to those species characteristic of the NWR. However, Jensen and Dochinger (1989) have exposed red maple to low concentrations of both SO_2 and O_3 and determined that red maple is sensitive and exhibits some growth reduction (Table 8-9) when exposed to these levels.

The maximum annual SO_2 concentration is predicted to be 3.0022 $\mu g/m^3$ (background plus proposed project contribution). The annual O3 concentration was assumed to be 55 $\mu g/m^3$ (based on monitoring by FDER and the Florida Acid Deposition Study (Environmental Science & Engineering, 1988, 1989). Since it is not possible to model how the emissions from the proposed project will affect the ambient O_3 concentration in the NWR, it was assumed for purposes of this analysis that the levels potentially occurring in the NWR would be equal to the ambient concentrations monitored at Gainesville, Florida (ESE, 1988, 1989).

As a result of this inability to predict ambient O_3 concentrations, it is difficult to predict with absolute certainty that synergistic effects may or may not occur on all species in the NWR as a result of the proposed project. However, the SO_2 and O_3 concentrations (3.0022 and 55 $\mu g/m^3$, respectively) are below the concentrations reported as causing growth reductions in red maple (52 and 137 $\mu g/m^3$), a species found within the NWR. In addition, the anticipated SO_2 and O_3 values in the NWR are a small percentage of the SO_2-O_3 synergism values reported in the literature (Table 8-9).

8.3.1.7 Sulfur and Nitrogen Deposition

Due to the growing awareness of decline in the health and vigor of forests, current research is focusing upon the effects of the addition of sulfur and nitrogen and associated generally pollutants to forest ecosystems. Sulfur and nitrogen additions are thought to affect forests through soil influences, foliar leaching, carbon allocation, winter injury, reproduction and regeneration, and insect and pathogen influences (Fox et al., 1989). The U.S. Forest Service (Fox et al., 1989) in developing a model for evaluating proposed new source contributions to pollution loadings in Class I areas, has considered the soil influence effects of S and N deposition, expressed in kg N or S per hectare per year.

The maximum predicted annual SO_2 concentration of 3.002 $\mu g/m^3$ (background plus proposed project contribution) and maximum predicted annual NO_2 concentration of 10.03 $\mu g/m^3$ (background plus proposed project contribution) yields a total S and N contribution of 3.1 and 6.35 kg/ha/yr, respectively. These values are equal to or below the green line values developed by Fox et al. (1989), which suggests the land manager of the Class I area recommend a permit be issued. It should be noted that these values are based on total concentrations (background values plus proposed project contribution) and that the proposed project contribution is several orders of magnitude lower than the background values used.

8.3.2 Soils

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

The contribution to the ambient concentrations of lead, beryllium, mercury, arsenic, antimony, barium, boron, cadmium, calcium, chromium, cobalt, copper, magnesium, manganese, nickel, selenium, vanadium, and zinc in the NWR from the proposed project has been estimated by the dispersion model. The deposition velocity assumes equal fractions for wet and dry depositions. Assuming a deposition velocity of 0.66 cm/sec (Edgerton and Lavery, 1990), the deposition flux is the product of the deposition velocity and the ambient trace element concentration. The deposition velocity assumed equal fractions for wet and dry depositons. Assuming that the trace elements deposited on the soil surface accumulate within the first 25 cm, a basis is provided for predicting average annual increases in soil trace element levels that could potentially result in the NWR from operation of the proposed project. A summary of the analysis of soil concentration increases is presented in Table 8-10. In order to provide some perspective for the comparison of trace element concentration increases in soils of the NWR, and lacking specific trace element concentration data for soils in the NWR, typical background trace element concentrations for soils of the eastern U.S. as reported by Shacklette and Boerngen (1984) and Dvorak et al. (1978) were used. In each reference, mean values were used with Shacklette and Boerngen (1984) as the primary data source and Dvorak et al. (1978) used to supplement data not found in Shacklette and Beorngen (1984).

Studies of model power plants by Dvorak et al. (1978), Dvorak and Pentecost et al. (1977), and Vaughan et al. (1975) predicted increases in soil trace element levels of less than 10 percent of the total endogenous concentrations over the life of the model plant. It was concluded that uptake by vegetation could not increase dramatically unless the forms of the deposited trace elements were considerably more available than the endogenous forms (Dvorak and Lewis et al., 1978; Environmental Research and Technology, 1978). The estimated percent increases over the anticipated 30 years of plant operation, assuming that the elements remained in the top 25 cm of soil over this period, ranged from 7.39x10-3 to 2.66x10-8 percent. The assessment of these estimated increases was based on a number of worst case conditions, which are not likely to occur during typical operation of the proposed project. Accordingly, an increase in the levels of all the evaluated trace elements in soil should not be perceptible on an annual basis in the NWR.

8.3.2.1 Arsenic

Arsenic (As) toxicity in plants is dependent on the concentration of soluble As and not the total As concentration in soils (Valkovic, 1975). Most plants can tolerate As concentrations in soils ranging from 1-40 ppm. Soil As concentrations greater than 2 ppm, soluble form, have been shown to cause damage to alfalfa and barley (Van de Caveye et al., 1936). Naturally occurring levels of As in plants range from 0.01 to 5.0 mg/kg (EPA, 1989). The estimated soil concentration increase of 2.5x10-8 mg As/kg/yr should not increase the existing soil As levels to toxic concentrations.

8.3.2.2 Antimony

Studies have indicated that plants can contain antimony levels ranging from 7-50 mg/kg without any symptoms of phytotoxicity (Gough et al., 1979). The annual deposition of antimony (6.87×10^{-7} mg/kg/yr) even when combined with typical soil background levels should not result in phytotoxicity symptoms.

8.3.2.3 Barium

Lawrey (1978) reports that naturally occurring levels of barium in plants range from 7.5 to 165 mg/kg. The estimated soil concentration increase of 6.05×10^{-6} mg/kg/yr should not elevate the soil concentrations of barium to levels where plants are affected adversely.

8.3.2.4 Beryllium

Beryllium (Be) is considered very toxic to plants. Toxic Be levels for bush beans were found to range from 3 to 5 ppm in nutrient solutions and in excess of 1 ppm in soil (Romney et al., 1962). The estimated soil concentration of 8.25×10^{-8} mg Be/kg/yr would be an insignificant increase and would not result in a soil concentration that exceeds the levels toxic to plants.

8.3.2.5 Boron

Boron (B) is an essential element for plant growth. The difference between essential and toxic amounts of B is relatively small. Boron concentrations of 0.05-0.10 ppm in solution culture are reported as safe for plants, while concentrations of 0.5-1 ppm are toxic for B sensitive plants (Kothny, 1973). Corn exhibits boron injury symptoms when the boron concentration is 25 ppm, while cotton leaves can accumulate 1,625 ppm boron before symptoms are manifest (Kothny, 1973). The estimated soil concentration increase of 2.04×10^{-6} mg B/kg/yr is insignificant and should not result in concentrations that would prove toxic to plants.

8.3.2.6 Cadmium

Cadmium is not an essential element for plant growth. Cadmium concentrations of 1 ppm are considered to be non-toxic (Valkovic, 1975 and Hutchinson and Czyrska, 1972). It is reported that 3 to 5 mg/kg retards the growth of plants (Gough et al., 1979). The estimated soil concentration increase of 3.30×10^{-7} mg Cd/kg/yr should not result in a soil concentration that limits plant growth.

8.3.2.7 Calcium

Calcium is an essential element for plant growth. The addition of 2.39×10^{-5} mg Ca/kg/yr should not result in either a positive or negative effect on plant growth. It is recognized that there is a growing concern that a supply of essential nutrients outside of the normal growing season may actually extend the growing season to the extent that the plant becomes more susceptible to disease or insect damage. The insignificant amount to be added from the operation of the proposed project should not be sufficient to result in any nutrient imbalances.

8.3.2.8 Chromium

Chromium toxicity of plants is a function of the chemical form, solubility, and concentration. Chromium, as chromic or chromate, in concentrations of 8-16 ppm has been found to cause chlorosis in sugar beets (Chapman, 1966). Chromate (Cr +6) at concentrations between 0.03 and 64 ppm have been observed to inhibit the growth of algae, while some mosses or bryophytes have been observed to accumulate amounts of Cr as high as 12,000 ppm without exhibiting injury symptoms (NAS, 1974). Gough et al. (1979) report that a soil concentration of 1,370 to 2,740 mg/kg chromium caused chlorosis in citrus, while liquid cultures that contained 150 mg/kg were toxic to seedlings. The estimated soil concentration increase of 1.50×10^{-6} mg Cr/kg/yr will not result in soil concentrations toxic to plants.

8.3.2.9 Cobalt

Cobalt (Co) is not an essential element for plant growth and is reported to be extremely toxic to plants (Bowen, 1966). Allen et al. (1990) reports that black gum (Nyssa slyvatica) and broomsedge (Andropogon spp.) are sensitive to excess cobalt concentrations as small as 1-216 mg/kg and 0.05 - 0.91 mg/kg, respectively. Other plants from other families can accumulate large concentrations of cobalt (2,500-17,700 mg/kg) through cobalt tolerance. The addition of 1.50×10^{-6} mg Co/kg/yr will not result in soil concentrations that exceed the plant toxicity level.

8.3.2.10 Copper

Copper (Cu) is commonly regarded as a macronutrient, that which is essential for plant growth. Typically the problems encountered with copper pertain to deficiencies rather than toxicities. Gough et al. (1979) report that citrus seedlings exhibited chlorosis when exposed to approximately 150 mg/kg of copper. Toxic symptoms have been observed when tissue concentrations reach 20 ppm (Chapman, 1966 and Valkovic, 1975). In comparison, the annual estimated soil concentration increase of 2.89×10^{-7} mg Cu/kg/yr will not result in a soil concentration toxic to plants.

8.3.2.11 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100 g/g generally retarded the growth of plants. In comparison, the estimated soil concentration increase of 2.75×10^{-7} mg Pb/kg/yr will not result in a soil concentration toxic to plants.

8.3.2.12 Manganese

Manganese (Mn) is an essential element for plant growth. It can be toxic in high concentrations, although it is less toxic than a number of other trace elements. Reuther et al. (1949) found that 1000 ppm Mn in leaves of valencia oranges was toxic. Alfalfa grown in acid soil with more than 50 ppm exchangeable Mn exhibited toxicity symptoms (Foy, 1964). Gough et al. (1979) found that Mn toxicity occurs at levels of 400 to 500 mg/kg. The estimated soil concentration increase of 4.40×10^{-7} mg Mn/kg/yr is a minute amount compared to the levels reported to be toxic.

8.3.2.13 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm (HgCl2) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy spanish moss plants with a mercury content of 0.5 mg/kg. The estimated soil concentration increase of 9.39×10^{-8} mg Hg/kg/yr will not result in concentrations toxic to plants.

8.3.2.14 Nickel

Nickel (Ni) is not an essential element for plant growth. Nickel enters plants primarily through the root system and is deposited in leaf tissue (Chapman, 1966; Tiffin, 1971). It has been reported that Ni concentrations in excess of 50 ppm in plants are toxic, although some plants endemic to serpentine soils may contain up to 6,100 ppm (NAS, 1975). Concentrations of Ni reported to result in yield reductions are 60 ppm for oats (500 ppm in the soil), 28 ppm in oat straw, and 44 ppm in alfalfa (NAS, 1975). The estimated soil concentration increase of 9.65×10^{-8} mg Ni/kg/yr will not result in the soil concentrations that are toxic to plants.

8.3.2.15 Selenium

Selenium (Se) is a nonessential element for plant growth, although it has been reported to stimulate the growth of a few plants at very low concentrations (Chapman, 1966). The absorption and accumulation of Se by plants is dependent upon the concentration and distribution of Se in the soil, chemical nature, seasonal variation in rainfall, plant species, growth stage, physiological condition of the plant, and the presence of other soil components. The primary indication of excess selenium in plants is growth inhibition. In grains, toxicity symptoms may be manifested by a chlorosis of some or all the leaves. It is reported in the literature that cereal grains and onions may accumulate 30 ppm Se without toxic effects, although grasses, clovers, and vegetables have a much lower tolerance (5 ppm) (Lisk, 1972). The estimated annual increase in soil concentrations (5.31×10^{-8} mg Se/kg/yr) will not result in toxic soil concentrations.

8.3.2.16 Vanadium

Vanadium (V) can accumulate to high levels (50 ppm) in plants without the plants exhibiting toxicity symptoms (Gough and Shacklette, 1976). The addition of 10 ppm V (calcium vanadate) to sandy soil was found to result in a decrease in the growth of orange seedlings (Chapman, 1966). All plants died when concentrations were increased to 150 ppm. Aller et al. (1990) reported phytotoxic responses in plants grown in soils containing 140 mg/kg. The estimated annual soil concentration increase of 2.14x10^{-6} mg V/kg/yr will not result in soil concentrations of V reported to be toxic to plants.

8.3.2.17 Zinc

Zinc (Zn) is an essential element for plant growth, although toxicity symptoms can occur at elevated levels reported to be as high as 300 mg/kg. Gough and Shacklete (1976) report that 12.5 percent total Zn in soil will stunt most vegetation. However, toxicity levels were found to vary considerably between species. Toxicity symptoms were observed in oat leaves when concentrations ranged from 1,700-7,500 ppm, and in tomato leaves when concentrations ranged from 526-1,489 ppm (Chapman, 1966). Zinc toxicity has also been found to vary with soil type, with sandy soils as the most toxic and clay-loam soils as the least (Chapman, 1966). The estimated soil concentration increase of 2.13x10^{-5} mg Zn/kg/yr will not result in soil concentrations toxic to plants.

In each case, the projected soil concentration increase is at least an order of magnitude less than reported soil concentrations. These small additions from the proposed project should not increase existing soil concentrations to levels toxic to plants.

8.3.3 Wildlife

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates. Accordingly, this analysis addresses only those air contaminants for which sufficient data exist.

Effects on wildlife from air pollutants are summarized in Table 8-11. It should be noted that most of the effects noted occur below the national secondary ambient air quality standards. In comparison to information in Table 8-11, the predicted annual SO_2 concentration of 3.0022

$\mu g/m^3$ (estimated background plus predicted increment in the NWR) is less than 25 percent of the concentration (13-157 $\mu g/m^3$, continually for 5 months) that resulted in a decreased abundance of deer mice. The predicted annual NO_2 concentration of 10.031 $\mu g/m^3$ (estimated background plus predicted increment in the NWR) is less than 15 percent of the concentration (96-958 $\mu g/m^3$, 8 hours per day for 122 days) reported to cause respiratory stress in guinea pigs. The estimated annual O_3 concentration in the NWR (59 $\mu g/m^3$), based on existing background levels in the vicinity of the NWR, cannot be assessed as there are no commensurate data for an annual averaging period. The estimated annual particulate concentration in the NWR (29.0033 $\mu g/m^3$), based on the estimated background plus predicted increment in the NWR, is approximately one third of the concentration reported to cause respiratory stress. In conclusion, it is highly unlikely, given the small predicted increment from the proposed project, that ambient levels would fall into those levels where effects in wildlife would be noted.

In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-on program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989). The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWR. TECO's Big Bend plant will have significant reductions by 1995 and other plants, including FPC's Crystal River plant, will reduce emissions by the year 2000. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWR, although the extent of the improvement is not readily quantifiable.

It is not possible at this time to accurately quantify the impacts of the proposed project on acid deposition conditions in the NWR and the resulting impacts on aquatic organisms. As indicated in the "National Acid Precipitation Assessment Program 1990 Integrated Assessment Report" (NAPAP, 1991), it is very difficult to determine explicitly which sources are influencing which receptors due to the many physical and chemical process which occur simultaneously in the atmosphere. Regional models have been developed which has improved the overall understanding of these processes. But, as stated in "Acid Deposition: State of the Science and

Technology" (NAPAP, 1991a), ". . . we are not yet in a position to make reliable estimates of the relationships between hydrogen ion deposition and the precursor emissions." However, on a qualitative basis, it can be said that due to the small emission increases that will be caused by the proposed project, increase, if any in acid deposition will be very small.

8.4 VISIBILITY IMPACTS

Section 169A of the CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Potential project impacts on visibility in the nearest Class I area, the Chassahowitzka National Wilderness Area, were estimated using the VISCREEN Version 1.01 (88341) model (EPA, 1988b). Impacts were calculated for PM and NO_2. Impacts were not calculated for SO_2 because, according to the model, SO_2 conversion to sulfates that can impact visibility is not significant at distances less than 200 km, and the Chassahowitzka is located between 118 and 135 km from the proposed project. The results of the VISCREEN analysis are presented in Table 8-1. Based on these results, the project will not significantly impair visibility in the Chassahowitzka Wilderness Area.

TABLE 8-1
ESTIMATED PROJECT IMPACTS AND BACKGROUND CONCENTRATIONS CLASS I AREA

Pollutant	Emissions (g/s)	Maximum Predicted Impact ($\mu g/m^3$)					Estimated Background ($\mu g/m^3$)
		1-hour	3-hour	8-hour	24-hour	Annual	
CO	4.84E+01	5.33E+00	3.00E+00	1.36E+00	4.31E-01	2.78E-02	1700
NO$_2$	1.60E+02	1.76E+01	9.95E+00	4.49E+00	1.43E+00	3.08E-02	10
SO$_2$	4.94E+01	5.44E+00	3.07E+00	1.38E+00	4.40E-01	2.23E-03	3
PM	8.58E+00	9.44E-01	5.32E-01	2.40E-01	7.64E-02	3.26E-03	29
VOC (O$_3$)	6.05E+00	6.66E-01	3.75E-01	1.69E-01	5.38E-02	3.86E-03	55
Lead	8.00E-03	8.80E-04	4.96E-04	2.24E-04	7.12E-05	3.11E-07	0.1
Beryllium	2.27E-03	2.50E-04	1.41E-04	6.36E-05	2.02E-05	8.81E-08	N/A
Mercury	2.72E-03	2.99E-04	1.69E-04	7.62E-05	2.42E-05	1.06E-07	N/A
H$_2$SO$_4$	4.89E+00	5.38E-01	3.03E-01	1.37E-01	4.35E-02	2.32E-04	N/A
Arsenic	3.80E-03	4.18E-04	1.84E-01	1.06E-04	3.38E-05	1.47E-07	N/A
Benzene	5.39E-02	5.93E-03	3.34E-03	1.51E-03	4.80E-04	3.67E-05	N/A
Antimony	2.00E-02	2.20E-03	1.24E-03	5.60E-04	1.78E-04	7.76E-07	N/A
Barium	1.77E-02	1.95E-03	1.10E-03	4.96E-04	1.58E-04	6.87E-07	N/A
Boron	5.91E-02	6.50E-03	3.66E-03	1.65E-03	5.26E-04	2.29E-06	N/A
Cadmium	9.53E-03	1.05E-03	5.91E-04	2.67E-04	8.48E-05	3.70E-07	N/A
Calcium	6.78E-01	7.46E-02	4.20E-02	1.90E-02	6.03E-03	2.63E-05	N/A
Chromium	4.31E-02	4.74E-03	2.67E-03	1.21E-03	3.84E-04	1.67E-06	N/A
Cobalt	8.23E-03	9.05E-04	5.10E-04	2.30E-04	7.32E-05	3.19E-07	N/A
Copper	2.45E-01	2.70E-02	1.52E-02	6.86E-03	2.18E-03	9.51E-06	N/A
Formaldehyde	1.75E-01	1.93E-02	1.09E-02	4.90E-03	1.56E-03	1.19E-04	N/A
Magnesium	2.11E-01	2.32E-02	1.31E-02	5.91E-03	1.88E-03	8.19E-06	N/A
Manganese	1.27E-01	1.40E-02	7.87E-03	3.56E-03	1.13E-03	4.93E-06	N/A
Nickel	1.54E-01	1.69E-02	9.55E-03	4.31E-03	1.37E-03	5.98E-06	N/A
Selenium	2.13E-02	2.34E-03	1.32E-03	5.96E-04	1.90E-04	8.27E-07	N/A
Vanadium	6.32E-02	6.95E-03	3.92E-03	1.77E-03	5.62E-04	2.45E-06	N/A
Zinc	6.20E-01	6.82E-02	3.84E-02	1.74E-02	5.52E-03	2.41E-05	N/A

Notes: Short-term values are highest, second-highest concentrations. See text for sources of estimated background concentrations.
N/A: Not Available
Source: Ebasco Environmental, 1992

TABLE 8-2
THRESHOLD NO_2 CONCENTRATIONS FOR VISIBLE INJURY TO PLANT SPECIES

Exposure Period (Hour)	Threshold Concentration[a] (μg/m³)	
	U.S. EPA (1976)	Thompson et al. (1974)
1	68620	1880-28200
2	37600	--
3	22560	--
4	16920	--
8	9024	4324-6580[b]
24	4324	1880

[a] Extrapolated values

[b] Values reported for 8-21 hours

TABLE 8-3
RESPONSE OR SENSITIVITY RATING OF VEGETATION TYPICAL OF THE PROPOSED PROJECT TO NO_2

Vegetation	NO_2 Concentration ($\mu g/m^3$)	Exposure Period	Rating or Response	Reference
Citrus sinensis	470	8 months	Intermediate sensitivity leaf abscission and reduced yield	Taylor and MacLean (1970) Thompson et al. (1970)
Melaleuca leucadendra	--	--	Moderately sensitive	MacLean et al. (1968)
Citrus sinensis (Marsh seedless grapefruit Valencia orange Tangelo orange Hamlin orange Temple orange)	376000	4-8 hours	Necrotic areas along succulent young shoots	MacLean et al. (1968)
	470000	1 hour	Necrotic areas along succulent young shoots	MacLean et al. (1968)

TABLE 8-4
THRESHOLD SO_2 CONCENTRATIONS FOR VISIBLE INJURY TO SENSITIVE VEGETATION

Exposure Period (hour)	Threshold Concentration ($\mu g/m^3$)			
	Jacobsen (1977)	Jones et al. (1974)	Linzon (1973)	USEPA (1973)
1	2000	1300-2620	1834	1300-7860
2	1050	--	1048	655-5240
3	850	786-1572	785(a)	400-3750(a)
4	750	--	681	262-2620
8	500	--	472	131-1310

(a) Interpolated value

TABLE 8-5
RESPONSE OR SENSITIVITY RATING OF VEGETATION TYPICAL OF THE PROPOSED PROJECT TO SO_2

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Vegetation	SO_2 Concentration ($\mu g/m^3$)	Exposure Period	Rating or Response	Reference
Acer sp. (maples)	118 -- 2620-5240 1572-2096	Growing season -- 1 hour 3 hours	No leaf injury Resistant Threshold level Threshold level	Fed Am Soc Exp Bio (1973) Sucoff and Bailey (1971) Jones et al. (1974) Jones et al. (1974)
Acer rubrum (red maple)	-- 786	-- 5 hours	Tolerant 11% Leaf injury(a)	USDA (1972) Davis and Shelly (1992)
Citrus sp.	--	--	Tolerant	USEPA (1976)
Citrus surantium	2620	2 hours/day 40 days	No leaf injury, decrease in total linear growth	Fed Am Soc Exp Bio (1973)
Citrus mobillis var. unshiu	2620	2 hours/day 40 days	No leaf injury	Fed Am Soc Exp Bio (1973)
Citrus sinensis (Koethon orange)	2096	10 days	No visible injury Decreased growth	Mat Sushima and Brewer (1972)
Fragaria ananassa	2620	6 hours/day 4 days	No leaf injury	Rajput et al. (1977)
Pinus sp. (southern pines)	3930-5240 2620-5240 1572-2096	Peak 1 hour 3 hours	Sensitive Sensitive Sensitive	Jones et al. (1974) Jones et al. (1974) Jones et al. (1974)
Pteridium aquilium (brackenfern)	--	--	Sensitive	USEPA (1976)
Quercus virginiana (live oak)	--	--	Tolerant	Loomis and Padgett (1973)

TABLE 8-5

RESPONSE OR SENSITIVITY RATING OF VEGETATION TYPICAL OF THE PROPOSED PROJECT TO SO_2

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Vegetation	SO_2 Concentration ($\mu g/m^3$)	Exposure Period	Rating or Response	Reference
Rhus spp. (summacs)	2620-3920	Peak	Sensitive	Jones et al. (1974)
	1310-2620	1 hour	Sensitive	Jones et al. (1974)
Rubus spp.	2620-3930	Peak	Sensitive	Jones et al. (1974)
	1310-2620	1 hour	Sensitive	Jones et al. (1974)
	786-1572	3 hours	Sensitive	Jones et al. (1974)
Taxodium distichum (bald cypress)	2620	48 hours	Reduced growth	Shanklin and Kozlowski (1985)

[a] Exposed to O_3 and acid precipitation as well as SO_2

TABLE 8-6
THRESHOLD O_3 CONCENTRATIONS FOR VISIBLE INJURY TO PLANT SPECIES[a]

Exposure Period (hour)	Ozone Concentration ($\mu g/m^3$)		
	Sensitive	Intermediate	Tolerant
0.5	294-588	490-1176	980
1.0	196-490	392-784	686
2.0	137-392	294-588	490
4.0	98-294	196-490	392
8.0	59-196	157-392	294

[a] Heggestad and Heck (1971)

TABLE 8-7

RESPONSE OR SENSITIVITY RATING OF VEGETATION TYPICAL OF THE PROJECT TO OZONE

Vegetation	O_3 Concentration ($\mu g/m^3$)	Exposure Period	Impact Area Rating or Response	Reference
Acer rubrum (Red maple)	--	--	Tolerant	USDA (1972)
Acer rubrum	178	7 hours/day 8-12 weeks	Leaf injury	Davis and Shelly (1992)
	156	7 hours/day 8-12 weeks	11% leaf injury Less growth/biomass	
Citrus sp.	--	--	Sensitive	USEPA (1976)
Cornus sp.	--	--	Tolerant	USEPA (1976)
Liquidembar stryacilflua (sweetgum)	52	8 hours/day 3 days/week 16 weeks	Sensitive Growth reduction	Jensen and Dochinger, (1989)
Nyssa sylvatica (Blackgum)	--	--	Tolerant	USEPA (1976)
Parthenocissus quinquefolia (Virginia creeper)	784	4 hours/day 14 days	Leaf injury	Treshow (1970)
Pinus elliottii (Slash pine)	149-203 (Seasonal mean)	112 days	Increased reduction in growth with increasing O_3 concentrations	Hogsett et al. (1985)
Quercus rubra (Red Oak)	78	7 hours/day 8-12 weeks	Leaf injury	Davis and Shelly (1992)
	156	7 hours/day 8-12 weeks	5% leaf injury Less growth/biomass	

TABLE 8-8
RESPONSE OR SENSITIVITY RATING OF VEGETATION TO MIXTURES OF SO_2 AND NO_2

Vegetation	SO_2 Concentration ($\mu g/m^3$)	NO_2 Concentration ($\mu g/m^3$)	Exposure Period	Rating or Response
Glycine max (Soybean)	131	94	4 hours	Slight leaf discoloration
	131-655	94-470	4 hours	Greater than additive effort
	262	188	4 hours	Leaf injury (35%)
	262	282	4 hours	Leaf injury (20%)
	524	376	4 hours	Leaf injury (9%)
	262	94	4 hours	No leaf injury
Medicago sativa	655	470	1 hour	9% inhibition of CO_2 uptake
	655	470	2 hours	15% inhibition of CO_2 uptake
Nicotiana tabacum (Tobacco)	262	188	4 hours	Leaf injury (11%)
	262	282	4 hours	Leaf injury (18%)
Lycopersicon esculentum (Tomato)	262	188	4 hours	Leaf injury (1%)
	262	282	4 hours	Leaf injury (17%)

TABLE 8-9

RESPONSE OR SENSITIVITY RATING OF VEGETATION TO MIXTURES OF SO_2 AND O_3

PAGE 1 OF 2

Vegetation	SO_2 Concentration ($\mu g/m^3$)	O_3 Concentration ($\mu g/m^3$)	Exposure Period	Rating or Response	Reference
Acer rubrum (red maple)	52	137	5 hours/day 3 days/week, 16 weeks	Sensitive Growth reduction	Jensen and Dochinger (1989)
	52	294	8 hours/day 3 days/week, 16 weeks	Sensitive Growth reduction	Jensen and Dochinger (1989)
Brassica oleracea capitata (Cabbage)	1310	98	4 hours	Leaf injury (4%)	Tingey et al. (1973b)
	262	196	4 hours	Leaf injury (22%)	Tingey et al. (1973b)
	655	196	4 hours	Leaf injury (14%)	Tingey et al. (1973b)
	1310	98	4 hours	Leaf injury (54%)	Tingey et al. (1973b)
Fragaria ananassa (strawberry)	2620	980	6 hours/day 4 days	Leaf injury	Rajput et al. (1977)
Fraxinus pennsylvanica (green ash)	209	196	4 hours/day 5 days/week, 6 weeks	Reduced growth(a)	Chappelka et al. (1988)
Glycine max (soybean)	2620	196	4 hours	Additive effect	USEPA (1976)
	131	98	6 hours	Leaf injury and decreased growth	Tingey et al. (1973b)
	98	98	6 hours	Leaf injury and decreased growth	Heagle et al. (1974)
	196	196	6 hours	Leaf injury and decreased growth	Heagle et al. (1974)
	655	98	4 hours	No leaf injury	Tingey et al. (1973a)
	2620	196	4 hours	Leaf injury (1%)	Tingey et al. (1973a)
Gossypium sp. (cotton)	734-838	176-216	10 weeks	Leaf injury and chlorosis	Fed Am Soc E Bio (1975)

TABLE 8-9
RESPONSE OR SENSITIVITY RATING OF VEGETATION TO MIXTURES OF SO_2 AND O_3

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Vegetation	SO_2 Concentration ($\mu g/m^3$)	O_3 Concentratio n ($\mu g/m^3$)	Exposure Period	Rating or Response	Reference
<u>Liquidambar</u> <u>stryaciflua</u> (sweetgum)	52	137	8 hours/day 3 days/week, 16 weeks	Sensitive Growth reduction	Jensen and Dochinger (1989)
	52	294	8 hours/day 3 days/week, 16 weeks	Sensitive Growth reduction	Jensen and Dochinger (1989)
<u>Lycopersicon</u> <u>esculentum</u> (tomato)	1310	98	4 hours	Leaf injury (1%)	Tingey et al. (1973b)
	262	196	4 hours	Leaf injury (50%)	Tingey et al. (1973b)
	655	196	4 hours	Leaf injury (10%)	Tingey et al. (1973b)
	1310	196	4 hours	Leaf injury (13%)	Tingey et al. (1973b)
<u>Medicago</u> <u>sativa</u> (alfalfa)	1310	98	4 hours	Leaf injury (2%)	Tingey et al. (1973b)
	262	196	4 hours	Leaf injury (24%)	Tingey et al. (1973b)
	655	196	4 hours	Leaf injury (21%)	Tingey et al. (1973b)
	1310	196	4 hours	Leaf injury (60%)	Tingey et al. (1973b)
<u>Nicotiana</u> <u>tabacum</u>	1310	98	4 hours	Leaf injury (60%)	Tingey et al. (1973b)
	262	196	4 hours	Leaf injury (95%)	Tingey et al. (1973b)
	655	196	4 hours	Leaf injury (88%)	Tingey et al. (1973b)
	1310	196	4 hours	Leaf injury (96%)	Tingey et al. (1973b)

(a) In combination with simulated acid rain

TABLE 8-10
SUMMARY OF ESTIMATED TRACE SOIL CONCENTRATIONS DUE TO OPERATION OF THE PROPOSED PROJECT

Trace Elements	Projected Stack Emission Rate (g/sec)	Maximum Predicted Trace Element Concentration ($\mu g/m^3$)	Deposition Flux ($g/m^2/yr$)	Estimated Soil Concentration Increase (mg/kg/yr)	Average Background Soil Concentration	Percent Increase Due To Emissions From The Proposed Project	
						Per Annum	30 Year Plant Life
Lead	0.008	3.11E-07	6.47E-08	2.75E-07	14.00	1.97E-06	5.90E-05
Beryllium	0.0024	9.32E-08	1.94E-08	8.25E-08	0.55	1.50E-05	4.50E-04
Mercury	0.00272	1.06E-07	2.21E-08	9.39E-08	0.08	1.16E-04	3.48E-03
Arsenic	0.004	1.55E-07	3.23E-08	1.37E-07	4.80	2.86E-06	8.58E-05
Antimony	0.02	7.76E-07	1.62E-07	6.87E-07	0.52	1.32E-04	3.97E-03
Barium	0.176	6.83E-06	1.42E-06	6.05E-06	290.00	2.09E-06	6.26E-05
Boron	0.0592	2.30E-06	4.79E-07	2.04E-06	31.00	6.57E-06	1.97E-04
Cadmium	0.0096	3.73E-07	7.76E-08	3.30E-07	0.06	5.51E-04	1.65E-02
Calcium	0.697	2.70E-05	5.62E-06	2.39E-05	24,000.00	9.96E-08	2.99E-06
Chromium	0.0436	1.69E-06	3.52E-07	1.50E-06	33.00	4.54E-06	1.36E-04
Cobalt	0.0436	1.69E-06	3.52E-07	1.50E-06	5.90	2.54E-05	7.61E-04
Copper	0.0084	3.26E-07	6.79E-08	2.89E-07	13.00	2.22E-06	6.66E-05
Manganese	0.0128	4.97E-07	1.03E-07	4.40E-07	260.00	1.69E-07	5.08E-06
Nickel	0.0028	1.09E-07	2.27E-08	9.65E-08	11.00	8.78E-07	2.63E-05
Selenium	0.154	5.99E-06	1.25E-06	5.31E-06	0.30	1.77E-03	5.31E-02
Vanadium	0.0623	2.42E-06	5.04E-07	2.14E-06	43.00	4.98E-06	1.50E-04
Zinc	0.621	2.41E-05	5.02E-06	2.13E-05	40.00	5.34E-05	1.60E-03

TABLE 8-11

REPORTED EFFECTS IN WILDLIFE OF SELECTED AIR CONTAMINANTS

Pollutant	Concentration ($\mu g/m^3$)	Exposure	Reported Effect	Reference
Sulfur Dioxide	427-854	1 hour	Respiratory stress in guinea pigs	Newman and Schreiber (1988)
	267	7 hours/day 5 days/week, 10 weeks	Respiratory stress in rats	Newman and Schreiber (1988)
	13-157	Continually for 5 months	Decreased abundance of deer mice	Newman and Schreiber (1988)
Nitrogen Dioxide	1917	3 hours	Respiratory stress in mice	Trzeciak et al. (1977)
	96-958	8 hours/day, 122 days	Respiratory stress in guinea pigs	Gardner and Graham (1976)
Ozone	160-200	3 hours	Respiratory stress; increased susceptibility to respiratory infection in mice rats and rabbits	Newman and Schreiber (1988)
Particulates	120 (PbO_3)	Continually for 2 months	Respiratory stress, reduced respiratory disease defenses	Newman and Schreiber (1988)
	100 ($NiCl_2$)	2 hours	Decreased respiratory disease defenses in rats and hamsters	Newman and Schreiber (1988)

TABLE 8-12
VISIBILITY ANALYSIS

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                 Visual Effects Screening Analysis for
                     Source:  FPC POLK COUNTY SITE
                Class I Area:  CHASSAHOWITZKA WILDERNESS


                      ***   Level-1 Screening   ***
Input Emissions for

   Particulates     8.60  G/S
   NOx (as NO2)   160.00  G/S
   Primary NO2       .00  G/S
   Soot              .00  G/S
   Primary SO4

    **** Default particle Characteristics Assumed

                 Transport Scenario Specifications:

    Background Ozone:                    .04 ppm
    Background Visual Range:           25.00 km
    Source-Observer Distance:         117.90 km
    Min. Source-Class I Distance:     117.90 km
    Max. Source-Class I Distance:     137.30 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.  117.9    84.  2.00   .073        .05  -.001
    SKY      140.  84.  117.9    84.  2.00   .022        .05  -.001
    TERRAIN   10.  84.  117.9    84.  2.00   .003        .05   .000
    TERRAIN  140.  84.  117.9    84.  2.00   .001        .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.  114.1    94.  2.00   .074        .05  -.001
    SKY      140.  75.  114.1    94.  2.00   .024        .05  -.001
    TERRAIN   10.  60.  107.8   109.  2.00   .004        .05   .000
    TERRAIN  140.  60.  107.8   109.  2.00   .001        .05   .000
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Source: Ebasco Environmental, 1992.

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