ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

VIA FEDERAL EXPRESS
RETURN RECEIPT REQUESTED

February 28, 1991

Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. C. H. Fancy, Chief
Bureau of Air Regulation

Gentlemen:

Enclosed is an original and five copies of the Orlando Utilities Commission Indian River Combustion Turbine CT-C and CT-D application for amendment to authority to construct.

Each bound application prepared by our Consultant, Black & Veatch, contains a copy of FDER Form 17-1.202(1), the Ambient Air Quality Impact Assessment and the BACT Analysis. In addition, computer printouts and a diskette of all the air modeling computer runs supporting the application are enclosed.

This letter also requests an amendment to the start construction dates of units CT-C and CT-D and the expiration date in the authority to construct for these units (AC 05-146750 and AC 05-146751). The current scheduled commence construction date for CT-C is October 1991 and for CT-D is November 1991. We are requesting that the permit expiration date be extended to eighteen (18) months following issuance of this amendment to PSD-FL-130.

Attached you will find a letter of authorization for W. H. Herrington and the required $5000 application fee.

FEDERAL EXPRESS

[redacted]

QUESTIONS? CALL 800-238-5355 TOLL FREE.

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[redacted]

Date 3/4/91

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Your Phone Number (Very Important): (407) 423-9100
Company: ORLANDO UTILITIES COMMISSION
Department/Floor No.
Street Address: 20 S ORANGE AVE
City: ORLANDO State: FL ZIP Required: 32801

2 To (Recipient's Name) Please Print: Mr. C. H. Fancy, Chief
Bureau of Air Regulation
Recipient's Phone Number (Very Important): (904) 488-13
Company: FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Department/Floor No.
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip® Codes): 2600 Blair Stone Road (Twwin Towers Office
City: Tallahassee State: FL ZIP Required: 32399-2400

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.): 512156E

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If you have any questions, please call me at 407/423-9141 or Mr. Steve Day at Black & Veatch 913/339-2880.

Very truly yours,

J. S. Crall, Director
Environmental Division

JSC:rc
jc0228

Attachment

cc: P. Lewis
M. Linn
B. Andrews
C. Collins, C Dist.
G. Harper, EPA

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 305/423-9100

RECEIVED
BER - MAIL ROOM
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February 5, 1986

Environmental Protection Agency
345 Courtland Street, NE
Atlanta, GA 30308

Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Gentlemen:

This letter shall be the letter of authorization for William H. Herrington, Manager of Electric Operations for the Orlando Utilities Commission to sign statements on behalf of the Orlando Utilities Commission as they relate to applications to the Environmental Protection Agency and Florida Department of Environmental Regulation to operate and/or construct pollution sources.

Sincerely,

T. C. Pope
General Manager

TCP:ch

Orlando Utilities Commission
ORLANDO, FLORIDA
"Where Electricity Powers Progress"

63-215
631

No. 062379

PAY TO THE ORDER OF

DEPARTMENT OF ENVIRONMENTAL
REGULATION
2600 BLAIR STONE ROAD

TALLAHASSEE, FL 32399-2406

NOT VALID AFTER 180 DAYS

DATE 02/28/91 $5000.00

SUN BANK, N.A.
MAIN OFFICE:
ORLANDO, FLORIDA 32801

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AUTHORIZED SIGNATURE

⑈0000623794⑈ ⑆063102152⑆0215100140805⑈

Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

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001081

YOUNG, VAN ASSENDERP, VARNADOE & BENTON, P. A.
ATTORNEYS AT LAW

C. LAURENCE KEESEY

GALLIE'S HALL
225 SOUTH ADAMS STREET
POST OFFICE BOX 1833
TALLAHASSEE, FLORIDA 32302-1833
TELEPHONE (904) 222-7206

ORLANDO UTILITIES COMMISSION
INDIAN RIVER PLANT--GAS TURBINE ADDITIONS
FILE NO. 17135.22.0401

APPLICATION TO AMEND PERMITS NOS. AC-05-146750 and AC-05-146751
TO CONSTRUCT A MAJOR EMITTING FACILITY IN ACCORDANCE
WITH PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS

FEBRUARY 1991

BLACK & VEATCH

Question and Comment
Indian River

(1) Item C Permit - Question
Water injection to Control NO_x emission but Cost estimation "not available for water treatment and injection". Need This!

Comments

- .3% S #2 fuel and Natural Gas as fuel
- 42/25 ppmvd (#2 fuel oil/NATURAL GAS) NO_x
- Desire to use N.G. AS primary fuel but #2 oil if N.G is unavailable or is economically more feasible
- Two W CT (110MW) instead of ~~4~~ TWO GE (35MW) CT
  already installed (2) 35MW CT's
- Operate 8760 HRS/yr
- #2 fuel oil worst Case burn rate
  (2) GE CT 534.1 MMBTU/H
  2 W CT 1,345.5 MMBTU/H
  HHV = 18,582 BTU/LB for #2 Fuel oil

(2) Page 3-3
~~The table indicates that the emissions for SO_2, NO_x, CO and PM are significantly higher per unit for W vs G.E. Even with two 110MW units instead of ~~four~~ TWO 35MW UNITS the emission seem ~~are~~ greater than expected. Please discuss reasons and provide basis for Calculations~~

(Over)

Table 4-1 Provides BACT Comparable Cost data for NO_x Plus SCR. Please discuss Calculations and the basis for ~~calculation~~. All cost estimates, i.e. "SCR Reactors manufacturer quotes dated ___."

SCR and SNCR are rejected for mostly technical reasons - Cost of Cooling Water (SCR) and need for higher exhaust temperature (SNCR). Do you have any plans to convert the simple cycle to a Combined Cycle?

You request 8760 hrs/yr operating hours, normally simple cycle Combustion Turbines are used as peaking units and operate less than 2500 hrs/yr. Can you reduce the hours/year to 2000?

Orlando Utilities
Indian River

(4) 35 mw Simple Cycle Combustion Turbine
Construction permit issued 9/1/88.
(2) units operating permits 8/30/90

Now adding Two 110 mw Simple Cycle W Combustion Turbines instead of GE units

- will include Water injection to control NO_x emission and Low NO_x burner design
- asking for 8760 HRS/yr

- Emission page 3-5
  CO, NO_x, SO_2, TSP, PM10, VOC
  Be and H_2SO_4 mist exceed PSD.

- Low NO_x burners and Water injection will reduce NO_x emission to 25/42 PPMVd (@15% O_2) burning N.G. or oil respectively. (Page 4-11) BACT

- Use of .3% Sulfur oil will be BACT.

- CO, VOC, Particulates and BE will be Controlled by Good Combustion

Patty

(407) 423-9141

Jim Crow, Orlando Util

Indian River Facility

Permit FL 130

2 units built

2 units not built

Amend or modify) Cost for two units become larger

(1) Date for start Now

(2) W 100 MW EACH instead of 60 MW GE

How much $ to send?

17.4.05 p4 p8.1
4. p4 p4.3 > $5000 fee

Can we discuss?

Preston

Mot Lin - Modeling

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APPENDICES

1.0 Introduction

In January 1988, Orlando Utilities Commission (OUC) submitted a PSD permit application to construct four new nominal 35 MW (50 MW peak capacity) simple cycle combustion turbines at their Indian River generating station near Titusville, Florida. The application specified four General Electric (GE) Frame 6 combustion turbines, with provisions for the immediate installation of units A and B, and phased construction for the final two units (C and D). Construction permits were issued by the Florida Department of Environmental Regulation (FDER) for all four units on September 1, 1988. Units A and B were installed shortly after permit issuance. Operating permits were issued for these units on August 30, 1990.

The construction of the third and fourth combustion turbines was initially scheduled to begin on November 1, 1989, and November 1, 1990, respectively. However, because of increasing power needs in central Florida, the design of the Indian River facility has been revised. The new design substitutes two nominal 110 MW (129 MW peak capacity) Westinghouse 501-D5 combustion turbines for the previously proposed GE units.

An amendment for two of the existing PSD construction permits (AC-05-146750 and AC-05-146751), with associated air quality dispersion modeling and BACT determination, is necessary prior to installation of these two units. The air dispersion modeling is needed to evaluate the ambient air quality impacts of the two Westinghouse units in conjunction with the two existing GE units. The BACT determination is required per the existing permit's specific condition 15 to evaluate the latest technologies available to reduce pollutant emissions from the Westinghouse combustion turbines. The BACT determination provided in this application is based solely on the two proposed Westinghouse units.

This document, along with the attached "Application to Amend Authority to Construct Air Pollution Sources" forms (DER Form 17-1.202(1)) should be considered a formal request to amend the PSD construction permits for Units C and D at the Indian River facility. This document contains all the necessary information to demonstrate the facility's continued compliance with all applicable federal and state air quality standards.

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

$5000 pd. 3-7-91 Recpt. #151252

RTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207

AC 05-193920
PSD-FL-173

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

G. DOUG DUTTON
DISTRICT MANAGER

AMEND AUTHORITY TO
APPLICATION TO ~~OPERATE~~/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine Facility [X] New[1] [ ] Existing[1]

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

COMPANY NAME: Orlando Utilities Commission COUNTY: Brevard

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) 4-Unit Combustion Turbine Facility

SOURCE LOCATION: ~~Street~~ XXXXXX Indian River Plant City Titusville

UTM: East 521.5 km North 3151.6 km

Latitude 28 ° 29 ' 32 "N Longitude 80 ° 46 ' 59 "W

APPLICANT NAME AND TITLE: Orlando Utilities Commission

APPLICANT ADDRESS: 500 South Orange Avenue, Orlando, FL 32802

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Orlando Utilities Commissio

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

*Attach letter of authorization

Signed: [signature]

William H. Herrington, Manager Electric Operatio
Name and Title (Please Type)

Date: 3/5/91 Telephone No. 407/423-9100

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

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

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

DER Form 17-1.202(1)
Effective October 31, 1982

the pollution control facilities, when properly maintained and operated, will discha[rge] an effluent that complies with all applicable statutes of the State of Florida and t[he] rules and regulations of the department. It is also agreed that the undersigned wil[l] furnish, if authorized by the owner, the applicant a set of instructions for the pro[per] maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed ________________

Steven M. Day
Name (Please Type)

Black & Veatch
Company Name (Please Type)

P.O. Box 8405, Kansas City, MO 64114
Mailing Address (Please Type)

Florida Registration No. 43028 Date: February 26, 1991 Telephone No. 913-339-2000

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.

A project description is provided in Section 2 of this Application to Amend. The project will result in full compliance.

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

Start of Construction October 1991 Completion of Construction September 1992

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

The amended Units C & D will be equipped with water injection to control NO_x emissions. However, a cost estimate for the water treatment and injection system is not available at this time.

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

Construction Permits: AC-05-146750 - December 8, 1989

AC-05-146751 - December 8, 1989

E. Requested permitted equipment operating time: hrs/day_____; days/wk_____; wks/yr_____

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? N/A

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

   c. If yes, list non-attainment pollutants. N/A

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

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

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

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

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

   a. If yes, for what pollutants? N/A

   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.

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		
XX N/A				

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

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

2. Product Weight (lbs/hr): N/A

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]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	
			(See Section 3.0 of the Application to Amend)				

[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).

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)
(See Section 4.0 of the Application to Amend)				

E. Fuels - Units C & D only

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas @ ISO	Base Load	1.42 mcf/h/unit	1,226/unit
No. 2 Fuel Oil @ ISO	Base Load	9,057 gal/h/unit	1,185/unit
Natural Gas (worst-case)	Peak Load	1.54 mcf/h/unit	1,354/unit
No. 2 Fuel Oil (worst-case)	Peak Load	10,282 gal/h/unit	1,346/unit

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

Fuel Analysis: (Typical No. 2 Fuel Oil)

Percent Sulfur: 0.30 (max) Percent Ash: ______

Density: 7.05 lbs/gal Typical Percent Nitrogen: ______

Heat Capacity: 18,582 BTU/lb 131,003 BTU/gal

Other Fuel Contaminants (which may cause air pollution): See Section 4.0 of the Application to Amend

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

Annual Average None Maximum None

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

No liquid or solid wastes will be generated.

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

Stack Height: See Section 3.0 of the Application to Amend ft. Stack Diameter: ______ ft.

Gas Flow Rate: ______ ACFM ______ DSCFM Gas Exit Temperature: ______ °F

Water Vapor Content: ______ % Velocity: ______ FPS

SECTION IV: INCINERATOR INFORMATION

N/A

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 Type	Fuel BTU/hr	Temperature (°F)
Primary Chamber					
Secondary Chamber					

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

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

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

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

[ ] Other (specify) ______

Brief description of operating characteristics of control devices: ____________

____

____

____

____

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

____

____

____

____

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

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]

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.

3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).

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.)

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).

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.

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).

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.

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

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

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part applicable to the source?

[X] Yes [ ] No

Contaminant	Rate or Concentration
SO_2	150 ppmvd or 0.80 percent S in fuel
NO_x	75 ppmvd (plus heat rate adjustment)

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

[ ] Yes [X] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology? *Units C & D only

Contaminant	Rate or Concentration
SO_2	0.30 percent sulfur in fuel
NO_x	42/25 ppmvd (No. 2 fuel oil/natural gas)
CO	25 ppmvd
VOC	15/5 ppmvd (No. 2 fuel oil/natural gas)

D. Describe the existing control and treatment technology (if any). See Section 4.0 of the Application to Amend

1. Control Device/System:

2. Operating Principles:

3. Efficiency:*

4. Capital Costs:

*Explain method of determining

DER Form 17-1.202(1)
Effective November 30, 1982

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). See Section 4.0 of the Application to Amend

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 operat 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. Maintanance 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 operat 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: See Section 4.0 of the Application to Amend

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 No preconstruction monitoring required - See Section 6.0 of the Application to Amend

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

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

Other data recorded ____________________

Attach all data or statistical summaries to this application.

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

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling (per FDER approval)

1. 5 Year(s) of data from 01 / 01 / 81 (month day year) to 12 / 31 / 85 (month day year)

2. Surface data obtained from (location) Orlando, Florida

3. Upper air (mixing height) data obtained from (location) Tampa, Florida

4. Stability wind rose (STAR) data obtained from (location) N/A

C. Computer Models Used

1. Screen (UNAMAP 6) Modified? If yes, attach description.

2. ISCST (UNAMAP 6) Modified? If yes, attach description.

3. ________ Modified? If yes, attach description.

4. ________ Modified? If yes, attach description.

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

Applicants Maximum Allowable Emission Data Units C & D only

Pollutant	Emission Rate	
TSP / PM_{10}	13.6 g/s/unit (oil) 0.6 g/s/unit (natural gas)	grams/sec
SO^2	54.8 g/s/unit (oil) 0.1 g/s/unit (natural gas)	grams/sec

E. Emission Data Used in Modeling See Section 3.0 and 6.0 of the Application to Amend

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. See Application to Amend

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

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

2.0 Project Description

2.1 Project Site

The OUC Indian River generating station is located in Brevard County, Florida, on land currently owned by OUC. A project site location map is shown in Figure 2-1. The Indian River generating station is located adjacent to the Indian River, approximately 3 kilometers south of the John F. Kennedy Space Center. The site encompasses approximately 80 acres of which only about 2.5 acres will be disturbed for construction of the proposed Units C and D combustion turbines. Unpaved areas disturbed by construction activities will be landscaped to match the surrounding conditions.

The two Westinghouse combustion turbine units will be located directly south of the existing GE units. The approximate UTM coordinates of the Westinghouse units are as follows:

Unit C: 521.19 km East, 3151.54 km North

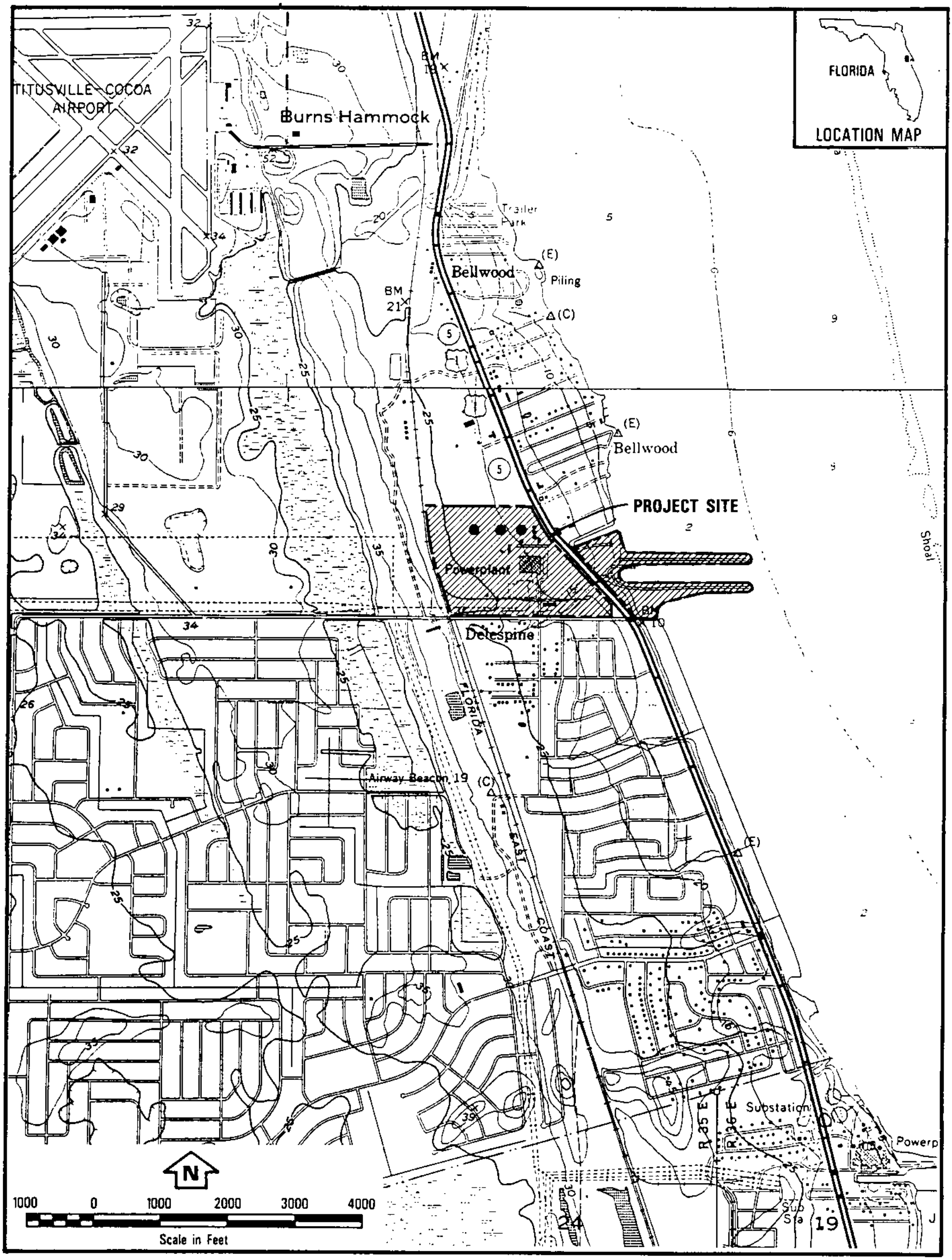
Unit D: 521.19 km East, 3151.50 km North

2.2 Project Facility

The original combustion turbine project plan called for the installation of four GE combustion turbine generators, a demineralized water storage tank, a No. 2 fuel oil storage tank, and a warehouse for storage of the combustion turbine generator spare parts. The original project also included provisions for the relocation of a 1 MW diesel generator from OUC's Lake Highland facility to the Indian River Plant Site.

The amended project plan revises only the final two combustion turbine units. All other facilities were installed with the initial Units A and B. A plant site arrangement is shown in Figure 2-2.

The Westinghouse 501-D5 simple cycle turbine package includes the combustion turbine engine assembly; generator and exciter; starting package; and inlet and exhaust systems. It is constructed in modules for easy shipping and installation. Coupled to the compressor end of the combustion turbine rotor shaft is the open air cooled generator with the exciter connected directly to it. Air enters the combustion turbine through an inlet duct located on the side of the unit. Within the duct are filters and a silencer for sound



Base Map Source: USGS,
Titusville and Sharpes, FL quadrangles

PROJECT SITE LOCATION

Figure 2-1

attenuation. The exhaust leaves the unit through a transition duct into a 50 foot vertical stack.

Ground water will be demineralized and used as injection water to the combustion turbines for NO_x control. All of the combustion turbine's auxiliary requirements (electrical distribution system) can be met with the existing equipment.

2.3 Project Operation

The addition of the Westinghouse combustion turbines is designed to have a minimal impact on the existing facility operations. A majority of the construction of the new turbines can be accomplished without disrupting utility services. However, short outages may be required for some electrical and piping interconnections to the existing systems. The Westinghouse combustion turbines are designed to operate 8,760 hours per year.

2.4 Project Fuels

The Westinghouse combustion turbines are designed to fire natural gas as the primary fuel and No. 2 fuel oil as a backup fuel. The combustion turbines are also designed with black start capability. The Indian River generating station receives natural gas from Florida Gas & Transmission, Citrus Industries Company, or on the spot market via the existing gas pipeline on a continual basis. The No. 2 fuel oil is transported to the site by truck. No. 2 fuel oil will be used when the natural gas supply is interrupted or if this fuel becomes economically advantageous. Of the two fuels, No. 2 fuel oil will produce higher pollutant emission rates than natural gas. Therefore, combustion and emission parameters for No. 2 fuel oil usage were used in the dispersion modeling to determine worst-case ambient air quality impacts.

3.0 Source Characterization

This section discusses the applicability of federal, state, and local air quality regulations, good engineering practice (GEP) stack height determination, stack parameters and source emission rates, and the current air quality status at the Indian River plant site. Current engineering estimates and the projections of the final design were used to establish the modeling parameters.

3.1 Applicability Of Regulations

The application to amend the existing PSD construction permits for Units C & D is subject to Prevention of Significant Deterioration (PSD) regulations because the original planned installation of four combustion turbines at the Indian River plant constituted a major modification to an existing major stationary source, and the plant is located in an area designated as "attainment" or "unclassifiable" for all applicable criteria pollutants. In addition, Specific Condition 15 in the construction permits require PSD review of any units for which construction is not commenced within 18 months of permit issuance. New Source Performance Standards (NSPSs) Subpart GG and Florida Air Pollution and Permit Rules and Regulations are also applicable.

3.2 GEP Stack Height Determination

A GEP stack height analysis was conducted for the existing and proposed buildings and structures at the Indian River plant. Pollutant dispersion from stacks built to the maximum GEP height will not be influenced by surrounding building turbulence. If stacks are built lower than GEP, special air quality modeling techniques such as downwash and cavity analysis are required to demonstrate compliance with air quality standards. EPA's Guideline For Determination of Good Engineering Practice Stack Height (1985) was used as a basis for this GEP analysis.

The existing GE and proposed Westinghouse combustion turbine stacks are located approximately 700 to 1,000 feet west of the existing Unit 3 steam generator building. At this distance, the combustion turbines are not influenced by this or any other existing structures at the plant. Therefore, only the combustion turbine structures themselves will influence the GEP stack height determinations.

The results of the GEP determinations and direction specific downwash parameters are given in Appendix A. The GEP stack height for Unit A (existing GE combustion turbine) is 70 feet. The remaining three combustion turbines all have calculated GEP stack heights of 100 feet. Because all four turbine stacks will be built to less than GEP height, building parameters from the combustion turbines were used to calculate direction specific building downwash conditions. The direction specific building downwash was incorporated into the revised air quality dispersion modeling analysis provided with this application. Building downwash was not evaluated in the original (1988) permit application.

3.3 Stack Parameters and Source Emissions

The stack parameters and source emission rates for fuel oil and natural gas firing of all four combustion turbines are given in Table 3-1. All calculations are based on preliminary engineering and/or manufacturer performance data. Stack parameters and emission rates were calculated for peak load operating conditions and 20 F, sea level (14.7 psi) pressure, and 60 percent relative humidity ambient conditions. These conditions represent the worst-case operating conditions at the facility.

Only No. 2 fuel oil combustion parameters were used in the dispersion modeling because the emissions from No. 2 fuel oil combustion are equal to or greater than those for natural gas combustion for each pollutant.

The estimated worst-case pollutant emissions from the four combustion turbines are based on a design fuel burn rate of 534.1 MBtu/h for the two GE units and 1,345.5 MBtu/h for the two Westinghouse units. These fuel burn rates represent a peak load condition while firing No. 2 fuel oil. A lower heating value (LHV) of 18,582 Btu/lb was used for the No. 2 fuel oil.

The NO_x emission estimates for the two existing GE Frame 6 combustion turbines are based on an approved BACT outlet concentration of 65 ppmvd (at 15 percent O_2) while firing No. 2 fuel oil. A BACT outlet concentration of 42 ppmvd (at 15 percent O_2) while firing No. 2 fuel oil was used for the proposed

Table 3-1

Combustion Turbine Stack Parameters and Emission Rates*

Parameters	GE Frame 6	Westinghouse 501-D5
Stack Height (ft)	36	50
Stack Diameter (ft)	12.36	22.14
Volumetric Flow (acfm)	786,290	1,970,269
Stack Exit Velocity (fpm)	6,552	5,117
Temperature (F)	1,035	977
Emissions:		
SO_2 (g/s/unit) - Fuel Oil	21.7	54.8
- Natural Gas	0.02	0.06
NO_x (g/s/unit) - Fuel Oil	18.6	29.1
- Natural Gas	10.9	17.2
CO (g/s/unit) - Fuel Oil	1.5	9.1
- Natural Gas	1.5	9.1
PM (g/s/unit) - Fuel Oil	3.1	13.6
- Natural Gas	0.4	0.6

*Stack parameters and emission rates are based on peak load operations at 20 F ambient temperature, sea level (14.7 psi) pressure, and 60 percent relative humidity. These conditions will result in the maximum heat input and pollutant emission rates.

Westinghouse combustion turbines. These emissions are based on low NO_x burner controls and the use of water injection to control NO_x emissions.

The SO_2 pollutant emission estimates for all four combustion turbines were based on firing No. 2 fuel oil with a maximum fuel sulfur content of 0.3 percent by weight. All other criteria pollutant emission rates, except lead, were obtained from data provided by the turbine manufacturers.

Emission rates for noncriteria and toxic air pollutant emissions were based on information contained in the EPA document entitled Toxic Air Pollutant Emission Factors- A Compilation for Selected Air Toxic Compounds and Sources, (EPA-450/2-88-006a). Emission rates for the PSD noncriteria pollutants beryllium (Be), lead (Pb), and mercury (Hg) were given in this document for fuel oil combustion. Sulfuric acid (H_2SO_4) mist emission rates were estimated as 3 percent of the SO_2 emission rate for fuel oil combustion. Asbestos, fluorides (F), and vinyl chloride (C_2H_3Cl) are not found in measurable quantities from No. 2 fuel oil firing. No measureable levels of any noncriteria pollutants are found to result from natural gas firing.

Be, Pb, and Hg are found in No. 2 fuel oil in trace amounts. A typical Be concentration in fuel oil is 2.5×10^{-6} pounds per million Btu. Pb concentrations are estimated at 2.8×10^{-5} pounds per million Btu. Hg concentrations are estimated to be 3.0×10^{-6} pounds per million Btu.

H_2SO_4 mist results from oxidation of the SO_2 in the flue gas to sulfur trioxide (SO_3). The SO_3 then combines with water vapor to form the sulfuric acid mist. Approximately 3 percent of the SO_2 is converted to sulfuric acid mist. Based on these estimates, the sulfuric acid mist concentration is 9.7×10^{-3} pounds per million Btu for No. 2 fuel oil combustion.

Table 3-2 presents the maximum potential annual emissions from the addition of all four combustion turbines. These emissions are based on ISO operating conditions. ISO conditions most closely approximate the annual operating conditions of these units. Revised ambient air quality modeling has been conducted for SO_2, NO_x, PM, and CO.

Table 3-2

Potential Annual Emissions From the Combustion Turbines

Pollutant	Potential Annual Emissions* 2-GE (tons)	2-WH (tons)	Total (tons)	PSD Significance Levels	Exc… PSD
CO	88	635	723	100	yes
NO_x	1,036	1,760	2,796	40	
SO_2	1,234	3,356	4,590	40	
TSP	175	838	1,013	25	
PM_{10}	175	838	1,013	15	
VOC	36	403	439	40	
Lead	0.1	0.3	0.4	0.6	NO
Asbestos	negl	negl	negl	0.007	NO
Beryllium	0.01	0.03	0.04	0.0004	yes
Mercury	0.01	0.03	0.04	0.1	NO
Vinyl Chloride	negl	negl	negl	1.0	NO
Fluorides	negl	negl	negl	3.0	NO
H_2SO_4 mist	37	101	138	7.0	yes
Total Reduced S	negl	negl	negl	10.0	NO
Reduced S	negl	negl	negl	10.0	
H_2S	negl	negl	negl	10.0	

*Estimated annual emission rates are based on operations at ISO conditions. ISO conditions are definnd as 59 F ambient temperature, sea level (14.7 psi) pressure, and 60 percent relative humidity. These conditions most closely approximate the annual operating conditions of these units.

4.0 Best Available Control Technology (BACT)

4.1 Introduction

OUC Indian River Plant is currently permitted to construct four GE Frame 6 simple cycle combustion turbines (Permit Nos. AC 05-144482, AC 05-146749, AC 05-146750, and AC 05-146751). Under these permits, the NO_x emission limits were set at 42 ppmvd or 65 ppmvd at 15 percent oxygen when burning natural gas or No. 2 fuel oil, respectively. These emission levels are achieved with water injection. The permit also stipulated that only natural gas or No. 2 fuel oil can be burned in the combustion turbine. SO_2 emissions are controlled by limiting the maximum sulfur content of the No. 2 fuel oil to 0.30 percent by weight.

The four turbines are being installed in two construction phases. In Phase I, OUC installed two of the four GE combustion turbines (peak output of 50 MW each). These two units are currently operating at the Indian River Plant. However, due to an increase in power demand, Phase II will consist of the installation and operation of two Westinghouse 501-D5 simple cycle combustion turbines. The peak output for these turbines is approximately 129 MW each and is significantly higher than was previously permitted. This change in equipment constitutes the need for an amendment to Permit Nos. AC 05-146750 and AC 05-146751.

Natural gas and No. 2 fuel oil will continue as the primary and backup fuels, respectively. Section 3.0 concluded that when 0.30 percent sulfur No. 2 fuel oil is used in all four turbines for the maximum project operation (8,760 hours per year), the emissions of the following regulated pollutants are subject to the provisions of the PSD Program.

- Nitrogen Oxides (NO_x)
- Particulate (Total and PM10)
- Sulfur Dioxide (SO_2)
- Beryllium (Be)
- Sulfuric Acid Mist (H_2SO_4)
- Carbon Monoxide (CO)
- Volatile Organic Compounds (VOC)

A BACT determination was previously performed for the four proposed GE turbines. The two operating GE turbines are using the control measures demonstrated as BACT from that evaluation. Specific condition 15 in the construction permits requires OUC to obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for any unit on which construction did not commence within 18 months of issuance of the permit. Construction for Units C and D has not begun within this time period. Consequently, this BACT analysis will address the control of applicable emissions of these PSD pollutants when burning either natural gas, or No. 2 fuel oil. Also included are evaluations of the effects of the BACT systems selected on the emissions of unregulated hazardous pollutants.

Under the federal Clean Air Act, BACT represents the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emission limits established by the applicable New Source Performance Standards (NSPS) Subpart GG.

This BACT analysis follows the general requirements of EPA's draft "top down" BACT guidance document (May 1990). This approach requires that the BACT analysis start by assuming the use of the Lowest Available Emission Rate (LAER) control alternative. Less efficient emission control technologies are subsequently evaluated if LAER is determined to be unreasonable considering the above factors.

The BACT analysis for Phase II of the OUC Indian River combustion turbine project is contained in the following sections. The cost data and predicted emission rates are for only the two proposed Westinghouse 501D combustion turbines.

4.2 Nitrogen Oxides Emissions Control

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. Nitrogen oxides formation can be limited by lowering combustion temperatures, and staging combustion (a reducing atmosphere followed by an oxidizing atmosphere).

The following subsections describe the potential NO_x control technologies, associated costs for the feasible technologies, and energy/environmental considerations.

4.2.1 Alternative NOx Emission Reduction Systems

The EPA has established an NSPS limitation for NO_x emissions from electric utility combustion turbines at 75 parts per million dry volume (ppmvd) at 15 percent oxygen (O_2), with a correction for fuel bound nitrogen content and turbine heat rate [40 CFR 60.332(b)]. A review of EPA's BACT/LAER Clearinghouse--A Compilation of Control Technology Determinations (1985 and 1990 editions) was performed to determine the control technology resulting in the lowest NO_x emission levels established to date for simple cycle combustion turbines. The identified technology was the use of water or steam injection with an improved low NO_x burner design.

For this BACT analysis, three potential control technologies are evaluated: selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and improved low NO_x burner design.

4.2.1.1 Selective Catalytic Reduction SCR. SCR is a post-combustion method for the 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 SCR process can achieve up to 90 percent reduction of NO_x with a new catalyst. An aged catalyst will provide a maximum of approximately 80 to 85 percent NO_x reduction.

The optimum flue gas temperature range for SCR operation is approximately 650 to 750 F. Flue gas from the simple cycle combustion turbines will typically be 950 F to 1,100 F. Therefore, the gas must be cooled prior to the injection of ammonia.

The most economical method to reduce the flue gas temperature is through humidification with water. The water quality for humidification must be free of sodium and salt deposits to protect the SCR catalyst. The project's proposed water treatment system is designed to provide only enough water to the CT units for turbine water injection. Therefore, an expansion of the water treatment facility would be required to demineralize the additional water required for humidification prior to the SCR.

4.2.1.2 Selective Non-catalytic Reduction (SNCR). NO_x emissions from a few fluidized bed combustion sources have been controlled through the installation of an SNCR systems such as Thermal $DeNO_x$. An SNCR system requires gas temperatures of at least 1,500 F for NO_x reduction. The temperature at the outlet of a combustion turbine is too low (950 F to 1,100 F) for such systems. Raising the flue gas exit temperature to 1,500 F would require supplemental heating of the flue gas and increases total emissions. Therefore, this alternative is judged technically unacceptable for a combustion turbine application and will not be evaluated further.

4.2.1.3 Improved Low NOx Burner Design. Combustion turbine manufacturers are marketing an improved low NO_x burner design. These burners provide improved air/fuel mixing and reduced flame temperatures. This burner technology along with water or steam injection result in lower concentrations of NO_x in comparison to standard combustion chamber design with water injection (25 versus 42 ppmvd when firing natural gas). Accordingly, the capital and annual cost of a low NO_x combustor to meet a 25/42 (natural gas/oil) ppmvd NO_x emission limit is considered base for this evaluation.

4.2.2 Capital and Operating Costs of Alternatives

Tables 4-1 through 4-4 present the capital and levelized annual costs for the two viable NO_x control systems for natural gas and No. 2 fuel oil combustion. The annual reduction of NO_x emissions is based on the Westinghouse turbines operating 8,760 hours per year. The differential capital costs for the SCR system include the costs of the catalytic reactors, ammonia storage/injection system, expansion of the water treatment facilities, and balance of plant equipment which includes foundations and erection of the ammonia storage system.

In addition to the equipment costs, the total capital costs include a contingency charge, escalation, indirect costs, and interest during construction. Contingency is added to account for uncertainties associated with estimating the capital costs for a project. Escalation is added to account for the increase

Table 4-1
Comparative Capital Costs of Alternative NO_x
Control Technology For Natural Gas Firing*

	Improved Low NO_x Burner Design Plus SCR	Improved Low NO_x Burner Design
Differential Combustion Turbine Costs	Base	Base
SCR Reactors	$4,780,000	NA
Ammonia Storage and Injection Equipment	$460,000	NA
Water Treatment, Storage and Injection Equipment	$2,800,000	Base
Balance-of-Plant	$140,000	Base
Direct Capital Cost (1990)	$8,180,000	Base
Contingency	$1,230,000	Base
Escalation	$820,000	Base
Direct Capital Cost	$10,230,000	Base
Indirects	$1,640,000	Base
Interest During Construction	$470,000	Base
Total Capital Costs (1992)	$12,340,000	Base

*Based on two Westinghouse turbines.

Table 4-2

Comparative Levelized Annual Costs of Alternative NO_x Control Technology During Natural Gas Firing*

	Improved Low NO_x Burner Design Plus SCR	Improved Low NO_x Burner Design
Operation and Maintenance Costs	$3,170,000	Base
Ammonia	$180,000	NA
Energy	$130,000	Base
Generating Cost Adjustment	$1,320,000	Base
Fixed Charges	$1,340,000	Base
Total Annual Costs	$6,140,000	Base
Annual NO_x Emissions	220 tons	1,090 tons
Incremental Annual NO_x Emission Reduction	870 tons	Base
Incremental Levelized Cost per Ton of NO_x Removed	$7,060	Base

*Based on two turbines and 8,760 hours/year of natural gas fired operation at ISO conditions (59 F and 60 percent relative humidity).

Table 4-3

Comparative Capital Costs of Alternative NO_x Control Technology for No. 2 Fuel Oil Firing*

	Improved Low NO_x Burner Design Plus SCR	Improved Low NO_x Burner Design
Differential Combustion Turbine Costs	Base	Base
SCR Reactors	$4,760,000	NA
Ammonia Storage and Injection Equipment	$460,000	NA
Water Treatment, Storage and Injection Equipment	$2,800,000	Base
Balance-of-Plant	$140,000	Base
Direct Capital Cost (1990)	$8,160,000	Base
Contingency	$1,220,000	Base
Escalation	$810,000	Base
Direct Capital Cost	$10,190,000	Base
Indirects	$1,630,000	Base
Interest During Construction	$460,000	Base
Total Capital Costs (1992)	$12,280,000	Base

*Based on two Westinghouse turbines.

Table 4-4

Comparative Levelized Annual Costs of Alternative NO_x Control Technology for No. 2 Fuel Oil Firing*

	Improved Low NO_x Burner Design Plus SCR	Improved Low NO_x Burner Design
Operation and Maintenance Costs	$4,170,000	Base
Ammonia	$300,000	NA
Energy	$130,000	Base
Generating Cost Adjustment	$1,240,000	Base
Fixed Charges	$1,340,000	Base
Total Annual Costs	$7,180,000	Base
Annual NO_x Emissions	380 tons	1,760 tons
Incremental Annual NO_x Emission Reduction	1,380 tons	Base
Incremental Levelized Cost per Ton of NO_x Removed	$5,200	Base

*Based on two turbines and 8,760 hours/year of No. 2 fuel oil fired operation at ISO conditions (59 F and 60 percent relative humidity).

in equipment and labor costs between the time of the evaluation and the midpoint of construction when the equipment costs are assumed to be paid.

Indirects are added to account for general costs, engineering services, field construction management services, and owner costs. Interest during construction accounts for interest paid to construct the facility and assumes that all payments are made in a lump sum at the midpoint of the construction period. Interest therefore, accrues from the midpoint of construction until commercial operation. The sum of all these items then represents the total capital cost for the installation. The evaluation criteria for this phase of the project is shown in Table 4-5.

Levelized annual costs include operating and maintenance costs (including catalyst replacement), ammonia additive, energy, lost generating capacity and fixed charges on the capital investment. The differential energy cost and lost generating capacity for the SCR alternative are the result of the reduced net output of the turbine due to the additional back pressure added by the SCR and the energy requirements of the associated equipment.

The incremental costs are presented for both natural gas and No. 2 fuel oil firing. A $6.1 million/year levelized annual cost for an SCR results in an incremental removal cost of approximately $7,060 per ton of NO_x reduction (natural gas). This system should be capable of reducing NO_x emissions by 870 tons per year. In comparison, an SCR for No. 2 fuel oil firing is estimated to have a $7.2 million/year levelized annual cost. This cost and a reduction of 1,380 tons of NO_x per year results in an incremental cost of about $5,200 per ton of NO_x reduction.

4.2.3 Energy and Environmental Considerations

The BACT analysis also considers energy and environmental factors. Compared to the improved low NO_x burner design with water or steam injection, the energy requirements of the SCR system would reduce the output of the combustion turbines by approximately 0.5 percent. This output loss directly effects the potential revenue for the facility.

An environmental consideration is that the catalyst can be contaminated because of the continued exposure to trace elements in the flue gas. Therefore, a spent catalyst must be handled and disposed of following hazardous waste procedures. Some catalytic elements are toxic and have to be replaced

Table 4-5

Evaluation Criteria

Contingency,%	15
Indirects,%	16
Escalation, %	7
Present Worth Discount Rate, %	8
Interest During Construction, %	8
Fixed Charges on Capital	10.87
Economic Life, yr	25
Capacity Factor, %	100
Ammonia, $/ton	250
Labor, $/yr	45,000
1990 Energy, mills/kwh	70
Commercial Operation	09/01/92
Catalyst Life, yrs	2

periodically. A toxic catalyst will require that hazardous waste disposal procedures must to be followed.

Additionally, ambient air quality modeling demonstrated that the project's ambient air quality impacts are less than the PSD significance criteria for NO_x of 1.0 mg/m^3 and also less than 1 percent of the Florida AAQS, when burning natural gas or No. 2 fuel oil. Meaningful improvements in ambient air quality cannot be achieved through the use of an SCR system.

The use of an SCR system could result in a negative environmental impact. Ammonia is considered a hazardous material and must be handled and stored with extreme care. Homes are located less than 500 feet from the plant boundary. An accidental release of ammonia could potentially result in serious impacts on the residents in these homes.

4.2.4 Conclusions

Installation of an SCR system with approximately 80 percent reduction would meet a NO_x emission limit of 5/9 ppmvd (natural gas/No. 2 fuel oil) and would add approximately $12.3 million to the capital cost of the project. This addition equipment increases the total project levelized annual costs by $6.1 to $7.2 million. The associated incremental removal cost is approximately $7,060 to $5,200 per ton of NO_x removed while burning natural gas or No. 2 fuel oil, respectively assuming 8,760 hours per year of facility operation.

Environmentally, ambient air quality modeling has indicated that the project's ambient air quality impacts will be well below NO_x increments and air quality standards significance levels. Also, there are potential environmental risks associated with the use of an SCR system due to unreacted ammonia being released to the atmosphere and disposal methods required for spent catalysts. Therefore, the NO_x BACT proposed for the Westinghouse 501D combustion turbines is the use of a improved low NO_x burner design with water injection to achieve NO_x emissions of 25/42 ppmvd (at 15 percent O_2) when burning natural gas or No. 2 fuel oil, respectively.

4.3 Sulfur Dioxide and Sulfuric Acid Mist Emissions

The NSPS established by the EPA for emissions from combustion turbines sets a maximum SO_2 level in the flue gas of 150 ppmvd (at 15 percent O_2) and a maximum fuel sulfur content of 0.8 percent by weight (40 CFR 60.333). The EPA has not established a combustion turbine NSPS for sulfuric acid mist (H_2SO_4). The turbine manufacturers' emission data indicate that approximately 3 percent of the SO_2 in the flue gas is oxidized to SO_3 which combines with water to form H_2SO_4.

Current BACT/LAER Clearinghouse documents do not list any natural gas, or No. 2 fuel oil fired combustion turbines that are required to use flue gas desulfurization (FGD) systems to meet SO_2 emission requirements. The addition of an FGD system would be an excessive method of SO_2 emission control. The significant capital and operating cost associated with FGD systems could seriously impact the economic feasibility of this phase of the project.

Most PSD permits for No. 2 fuel oil fired combustion turbines have limits for maximum allowable fuel sulfur contents. The use of low sulfur No. 2 fuel oil (maximum of 0.30 percent sulfur) would impose no significant differential capital costs on the project. Additionally ambient air quality dispersion modeling indicated that the facility will comply with PSD increments and air quality standards when burning 0.30 percent sulfur No. 2 fuel oil.

Based on economic, energy, and environmental considerations, the limitation of No. 2 fuel oil sulfur content to 0.30 percent by weight and firing natural gas are proposed as BACT for the SO_2 emissions.

4.4 Particulate Matter Emissions

The emission of particulates from the combustion turbine facility will be controlled by ensuring as complete combustion of the fuel as possible. The NSPS for combustion turbines do not establish an emission limit for particulates. A review of the EPA's BACT/LAER Clearinghouse documents did not reveal any post-combustion particulate matter control technologies being used on gas/oil fueled combustion turbines.

The natural gas and No. 2 fuel oil used for the facility will only contain trace quantities of particulates. Therefore, the proposed BACT for total suspended particulate and particulate matter smaller than 10 microns (PM_{10}) is complete combustion of the fuel.

4.5 Beryllium Emissions

The emissions of beryllium (Be) from the combustion turbine facility will be determined by the Be content of the fuels. Natural gas has no measurable Be content and No. 2 fuel oil typically contains a trace amount of Be. This amount is on the order of 2.5×10^{-6} pounds per million Btu (lbs/MBtu). The annual Be emissions when firing No. 2 fuel oil for 8,760 hours/year are predicted to be 0.03 tons per year. Therefore, Be is a significant PSD pollutant for the project.

Review of the EPA's BACT/LAER Clearinghouse documents did not reveal any combustion turbine project which has been required to install supplemental pollution control equipment to reduce Be emissions. Accordingly, complete combustion of the No. 2 fuel oil is proposed as BACT for Be emissions.

4.6 Carbon Monoxide and Volatile Organic Compounds

Carbon monoxide and VOC are formed during the incomplete combustion of the fuel. High combustion temperatures, adequate excess air and good fuel/air mixing during combustion will minimize CO and VOC emissions. Therefore, NO_x control methods of combustion staging and lowering combustion temperature by water injection can be counterproductive with regard to CO and VOC emissions.

To achieve the proposed NO_x BACT levels requires that these control techniques be used. Therefore, this turbine design will have significantly higher CO and VOC emissions than associated with a standard combustor. At the proposed BACT NO_x emissions of 25/42 ppmvd (gas/oil), the turbine will be capable of maintaining CO and VOC emission rates of 25 ppmvd and 5 ppmvd, respectively while burning natural gas. For fuel oil firing, the CO and VOC emission rates will be 25 ppmvd and 15 ppmvd respectively.

Based on a review of EPA's BACT/LAER Clearinghouse--A Compilation of Control Technology Determinations (1985 and 1990 editions), a combustion turbine with proper combustion control and an oxidizing catalyst that limits

CO emissions to 2 ppmvd represents LAER. An oxidizing catalyst is also LAER technology for VOC emissions but the specific ppmvd emission rate was not specified in the clearinghouse document.

4.6.1 Catalytic Reduction

Catalytic reduction is a post-combustion method for reduction of CO and VOC emissions. The process uses a precious metal to oxidize CO to CO_2 with the use of a catalyst and VOC hydrocarbons to CO_2 and H_2O. None of the catalyst components are considered toxic. The optimum flue gas temperature range for CO/VOC catalyst operation is between 850 F and 1,100 F. Flue gas from the combustion turbine will typically be between 950 F to 1,100 F. Therefore, a CO/VOC catalyst could be installed at the discharge of the combustion turbine.

4.6.2 Capital and Operating Costs

Table 4-6 presents the capital and levelized annual costs of a CO/VOC catalyst system. The CO and VOC emissions are based on firing No. 2 fuel oil for a maximum of 8,760 hours per year. The capital costs of the catalyst system includes the cost of the catalyst and balance-of-plant equipment. In addition to the 1990 equipment costs the total capital costs include a contingency charge, escalation, indirect costs, and interest during construction.

Levelized annual costs include operating and maintenance costs (including catalyst replacement), heat rate penalty, lost generating capacity, and fixed charges on capital investment.

A levelized annual cost for the catalyst system is calculated to be about $3.5 million/year. This system will result in a net total combined reduction of 620 tons per year of CO/VOC, while burning No. 2 fuel oil. This reduction results in an incremental removal cost of approximately $5,660 per ton of CO/VOC removed. This system is designed to limit CO emission to 5 ppmvd and VOC emissions to 7.5 ppmvd.

Table 4-6
Comparative Capital Costs of Alternative
CO/VOC Control Technology*

	Catalyst
Oxidation Reactors	$3,020,000
Balance of Plant	$100,000
Direct Capital Cost (1990)	$3,120,000
Contingency	$470,000
Escalation	$310,000
Direct Capital Cost	$3,900,000
Indirects	$620,000
Interest During Construction	$180,000
Total Capital Costs (1992)	$4,700,000
Operation and Maintenance Costs	$1,350,000
Heat Rate Penalty	$50,000
Generating Cost Adjustment	$1,600,000
Fixed Charges	$510,000
Total Annual Costs	$3,510,000
Annual CO and VOC Emissions	860 tons
Incremental Annual CO and VOC Emission Reduction	620 tons

*Based on two turbines and 8,760 hours/year of No. 2 fuel oil fired operation at ISO conditions (59 F and 60 percent relative humidity).

4.6.3 Other Considerations

A CO/VOC catalyst located downstream of the combustion turbine exhaust will produce an additional back pressure on the combustion turbine. The added back pressure will reduce the electrical output capability of the turbine. Additional back pressure of 3 to 4 inches of water gauge would reduce turbine output by approximately 600 KW per turbine. Lost generating capacity translates directly into lost project revenue. A CO/VOC catalyst will also oxidize SO_2 to SO_3 which upon condensation will form sulfuric acid. This formation will result in increased sulfuric acid emissions to the atmosphere.

4.6.4 Conclusions

On natural gas, VOC emissions are already quite low (5 ppmvd) and no further control technology could be feasibly applied.

A CO/VOC catalyst control system designed to meet a CO and VOC emission limits on oil of 5 ppmvd and 7.5 ppmvd, respectively would add approximately $4.7 million to the capital cost of the project. The total levelized annual costs for the project increases by $3.5 million resulting in an incremental removal cost of approximately $5,660 per ton of CO/VOC removed while burning No. 2 fuel oil for 8,760 hours per year (at 100 percent capacity). This catalyst control system would also be effective at reducing CO emissions on natural gas by the same amount as on oil.

Based on economic, energy, and environmental considerations, the CO and VOC BACT proposed for the project modification is the use of good combustion controls to achieve CO emissions of 25 ppmvd and VOC emissions of 15 ppmvd when burning No. 2 fuel oil and operating the unit for 8,760 hours per year.

4.7 Other Emissions

The project will emit trace quantities of other pollutants at levels which are below the significant emission levels established for the PSD program. Federal and state regulations do not require that BACT be applied for these pollutants, but the effects of the proposed BACT determinations on these pollutants must be considered.

4.7.1 Other Regulated and Hazardous Pollutants

Table 4-7 presents uncontrolled emission estimates for other regulated (mercury, and lead) and hazardous pollutants when firing No. 2 fuel oil. These emission rates have been developed based on manufacturers' information and on information contained in the EPA publications Toxic Air Pollutant Emission Factors--A Compilation For Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a).

The only identified methods of controlling the emission of these pollutants are complete combustion and the inherent quality of the fuel. Injection of water into the turbines to control NO_x emissions has a significant effect on controlling these pollutants. Complete combustion will be required to achieve the identified emission rates of formaldehyde.

Table 4-7

Other Regulated and Hazardous Pollutant Emissions

Pollutant	Emission Rate lb/MBtu	Annual Emission* tons
Arsenic	4.2 E-6	0.04
Beryllium	2.5 E-6	0.03
Cadmium	1.1 E-5	0.11
Chromium	4.8 E-5	0.50
Copper	2.8 E-4	2.90
Formaldehyde**	4.1 E-4	4.26
Lead	2.8 E-5	0.29
Manganese	2.6 E-5	0.27
Mercury	3.0 E-6	0.03
Nickel	1.7 E-4	1.76

*Annual emissions are total for two combustion turbines and are based on annual operation of 8,760 hours/year firing No. 2 fuel oil at ISO conditions (59 F and 60 percent relative humidity) and a fuel burn rate of 1,185 MBtu/h.

**Formaldehyde is also found in natural gas combustion. The emission rates are 8.8 E-5 lb/MBtu or 0.91 tpy.

5.0 Air Quality Dispersion Modeling Methodology

This section discusses the modeling methodology used for determining the ambient air quality impacts for CO, NO_x, SO_2, PM and other trace pollutants resulting from the addition of all four combustion turbines. The modeling methodology used in this analysis is consistent with the methodology used in the previously approved Indian River PSD permit application to construct the four GE Frame 6 combustion turbines submitted in 1988. The air quality modeling input and output computer files supporting this permit amendment will be provided to the FDER with this application.

5.1 Model Selection and Description

The EPA has developed modeling guidelines to provide a common basis for assessing air quality impacts. These guidelines are contained in the document entitled "Guideline on Air Quality Models (Revised)", July 1986, and supplemented in July 1987.

In order to assess the overall combustion turbine impacts, the modeling analyses incorporated simple terrain (terrain with elevations below stack top), rural land use, calculation of short-term and annual pollutant impacts, and building downwash effects. Within EPA's guideline document, the Industrial Source Complex Short-Term (ISCST) dispersion model is recommended for such modeling situations. The ISCST model is a steady-state Gaussian plume model which can be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. This model can also account for plume rise as a function of downwind distance, stack-tip downwash, buoyancy induced dispersion, and concentration adjustments for calm periods.

The ISCST model was used with five years of meteorological data to assess pollutant impacts at receptors in the vicinity of the Indian River generating station. The ISCST model was also used to perform the air dispersion modeling for the January 1988 application.

5.2 Model Options and Assumptions

EPA has issued guidelines to assist in determining what model options should be used. The following assumptions were made for this modeling analyses:

- Standard EPA default modeling options were applied.
- Building downwash was considered as appropriate. Direction-specific building dimensions were included to examine the effects of the building downwash.
- The highest second-highest short-term concentrations and the highest annual concentrations were used for comparison to the standards and PSD increments.
- The site was considered rural based on actual land use within 3 km.

5.3 Receptor Locations

The ISCST model allows the use of either a polar or rectangular receptor grid to predict ground-level concentrations. Polar receptor coordinates were selected for this analysis. The Unit A (existing GE unit) stack represents the center of the receptor array.

Receptor locations were selected with adequate density to ensure that the maximum and highest, second-highest predicted concentrations were determined. Because of the downwash conditions resulting from less than GEP stack heights on the combustion turbines, the short-term impacts were expected to occur within 1,000 meters of the plant. The long term impacts are also influenced by downwash conditions, but were expected to occur at a greater distance from the source.

Rings for the SO_2, NO_x, and TSP analysis were initially placed at 100 meter intervals from 200 to 600 meters, 250 meter intervals from 750 to 1,000 meters, 500 meter intervals from 1,500 meters to 5,000 meters, and 1,000 meter intervals from 6,000 to 15,000 meters. An additional ring was placed at 20,000 meters. Rings were placed out to 10,000 meters for the CO analysis. In addition to these rings, discrete receptors were spaced at 100 meter intervals around the plant fenceline.

The modeled receptor grid represents a denser grid than the one used for the 1988 application. The 1988 application placed receptors along rings located at 0.2, 0.4, 0.6, 0.8, 1.0, 1.2, 1.5, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, and 14 kilometers.

5.4 Meteorological Data

The ISCST dispersion model was used with five years (1981-1985) of sequential hourly surface meteorological data and twice-daily mixing depths. The surface and mixing depths data were selected from a location most representative of the general area being modeled. A representative location corresponds to the station closest to the location being modeled which is in the same climatic regime.

Hourly surface data from nearby Orlando, Florida and mixing depth data from Tampa, Florida were obtained from the FDER. The data were selected as the most representative of meteorological conditions at the Indian River plant. The data were preprocessed into the "CRSTER" format and all five years were used in the modeling. This is the same data set used for the 1988 PSD permit to construct application assessment.

6.0 Air Quality Impact Analysis

An air quality impact analysis was performed using the modeling methodology described in the previous section. The analysis was performed to determine which pollutants emitted from the four combustion turbines, have the potential to impact ambient air quality above PSD ambient air quality "significance levels". In addition, if significant impacts are determined, a "significant impact area" must be defined, preconstruction monitoring requirements need to be examined, and an ambient air quality standard (AAQS) and PSD increment consumption analysis must be performed.

6.1 Dispersion Modeling Results

The results of the dispersion modeling are presented in Table 6-1. Appendix B contains a listing of the modeling runs which show the extent of the ambient impacts. One hard copy set of the modeling runs and a computer diskette is included with the application.

The maximum impact location for the annual averaging period is 10,000 meters southwest of the plant. The highest, second-highest 1-hour, 3-hour, 8-hour, and 24-hour average impact locations are 256 meters southwest, 13,000 meters south, 498 meters east, and 477 meters east of the plant, respectively. The locations of the 1-hour, 8-hour, and 24-hour impacts are a direct result of building downwash effects. A secondary 3-hour highest, second highest impact of 19.3 mg/m^3 occurs at 498 meters east.

The highest, second-highest 1-hour and 8-hour average CO impacts are 8.1 and 1.2 ug/m^3, respectively. These values are well below the significant impact levels of 2,000 and 500 ug/m^3, respectively. Therefore, no further air quality impact analysis is required for CO.

The highest, second-highest 3-hour and 24-hour, and maximum annual average impacts for SO_2 are 21.0, 5.8, and 0.4 ug/m^3, respectively. The 3-hour and annual average values are below their respective significance levels of 25 and 1.0 ug/m^3. However, the 24-hour impact is slightly above it's significance level of 5.0 ug/m^3. Therefore, additional air quality impact analysis is required for SO_2.

Table 6-1
Dispersion Modeling Results
Fuel Oil Combustion

Modeled SO_2 Concentrations

Parameter	3-Hour Impact*	24-Hour Impact*	Annual Impact**
PSD Significance Level (ug/m^3)	25.0	5.0	1.0
Impact Concentration (ug/m^3)	21.0	5.8	0.4
Receptor Location:			
Distance (meters)	13,000	446.5	10,000
Direction (degrees)	180	90	240
Year	1982	1985	1984
Day/Period	68/2	137/1	--

Modeled CO Concentrations

Parameter	1-Hour Impact*	8-Hour Impact*
PSD Significance Level (ug/m^3)	2,000	500
Impact Concentration (ug/m^3)	8.1	1.2
Receptor Location:		
Distance (meters)	256.0	498.3
Direction (degrees)	200	95
Year	1981	1985
Day/Period	286/16	43/1

*Concentrations are highest, second-highest values.
**Concentrations are maximum values.

Pollutant specific dispersion modeling for NO_x and PM was not performed. The results of the SO_2 modeling can be used to show that NO_x and PM impacts will be below their respective significant impact levels.

The NO_x emission rates for each of the four combustion turbines are less than the associated SO_2 emission rate. Because the maximum annual SO_2 impact is below the significance criteria of 1.0 ug/m^3, it can be concluded that the maximum annual NO_x impact will also be below it's 1.0 ug/m^3 significance level. Therefore, no additional analysis was performed for NO_x.

The PM emission rates for each of the four combustion turbines are approximately one-fourth to one-seventh the corresponding SO_2 emission rate. If these ratios are applied to the maximum annual and highest, second-highest 24-hour modeled SO_2 impacts, the estimated PM impacts are well below their respective significant impact levels of 1.0 and 5.0 ug/m^3. Therefore, no additional analysis was performed for PM.

6.2 Significant Impact Area Determination

A significant impact area must be established for each applicable pollutant and averaging period for which an AAQS exists. In accordance with PSD guidance, the various pollutant impact areas are defined as the circular area whose radius is equal to the greatest distance from the source at which a significant impact level is predicted. If dispersion modeling demonstrates that a pollutant does not produce a significant impact, further air quality assessment of this pollutant is not required.

The significant impact criteria and pollutant impacts from the four combustion turbines were given in Table 6-1. The only pollutant that is predicted to have a significant impact is SO_2. The highest, second-highest 24-hour SO_2 impact was predicted to be 5.8 ug/m^3, located on the eastern plant fenceline, 447 meters from the Unit A stack (origin). Additional modeling results showed the significant impact area extends outward to a radius of 600 meters. No other averaging period for SO_2 exceeded its significance criteria. Therefore, 600 meters is the extent of the significance area for SO_2. Dispersion modeling also shows that only two receptors within the significant impact area (447 meters, 90 degrees and 500 meters, 90 degrees) have predicted impacts above the significance level. As a result, only these two receptor locations will be evaluated further.

6.3 Preconstruction Monitoring Requirements

Based on the results of the dispersion modeling, pollutant emissions from all four combustion turbines do not result in ambient impacts above PSD de minimis monitoring levels. Therefore, ambient monitoring will not be required.

6.4 AAQA and PSD Increment Compliance Determination

Criteria pollutants with ambient air quality impacts above significant ambient air quality levels must demonstrate compliance with AAQS and PSD increment consumption. Based on the dispersion modeling results, only SO_2 requires an AAQS and PSD increment compliance determination.

6.4.1 Interacting Source Inventories

In order to evaluate SO_2 AAQS and PSD increment compliance, interacting sources must be included in the air dispersion modeling analysis. A source emissions inventory was obtained from the FDER for all sources within 50.6 kilometers (significant impact area plus 50 kilometers) of the project site.

Initially, a method recommended by the North Carolina Bureau of Air Quality was used to eliminate insignificant sources from the inventory. Sources were dropped from the inventory if their ratio of annual emissions (tpy) divided by their distance from the Indian River plant site (km) was less than 20.

Next, the remaining sources were individually examined using the EPA-approved SCREEN (UNAMAP 6) air dispersion model to determine if each source would have a significant SO_2 impact on the two significant receptors near the Indian River plant. SCREEN conservatively predicts 1-hour concentrations using worst-case meteorology and user-specified source information. To convert 1-hour impacts to representative 24-hour average values, the 1-hour value is multiplied by 0.4.

Those sources that were shown to have insignificant maximum 24-hour average SO_2 impacts based on the screening modeling analysis, were dropped from the inventory. The remaining sources were included in the AAQS. A list of the remaining sources is given in Table 6-2.

The remaining list of interacting sources includes two OUC Stanton Energy Center sources, two Florida Power & Light sources, one Kennedy Space Center source, and the three existing steam boilers at the Indian River facility.

From the remaining list of interacting sources, FDER has stated that only the two Stanton Energy Center sources are SO_2 PSD sources. Therefore, only the four Indian River combustion turbines and the two Stanton Energy Center sources were included in the PSD increment analysis

6.4.2 AAQS Analysis

Sources that emit pollutants with resultant air quality impacts greater than the PSD significance levels are required to perform an air quality assessment to show compliance with the applicable AAQSs. The air quality assessment must evaluate the combined impacts from potential interacting sources, existing plant sources, and proposed new sources. These combined impacts are then added to a representative background pollutant concentration to arrive at a total maximum pollutant impact concentration.

Based on the earlier dispersion modeling results, the only pollutant that was predicted to have ambient impacts above PSD significance levels was SO_2. In addition, only the 24-hour averaging period impact exceeded the significance criteria. Therefore, this analysis only evaluated compliance with the 24-hour average SO_2 AAQS.

The ISCST dispersion model was used to assess the combined impacts from the existing Indian River steam and combustion turbine sources, the proposed Westinghouse combustion turbines at the Indian River plant, the OUC-SEC coal fired boilers, the Florida Power & Light Cape Canavarel ~~coal~~ oil/gas fired boilers, and the Kennedy Space Center source. The model predicted a combined highest, second-highest SO_2 concentration of 80.2 ug/m^3.

This predicted concentration was added to a representative background concentration of 44 ug/m^3 to arrive at a maximum predicted impact concentration of 124.2 ug/m^3. This concentration is below both the federal 24-hour SO_2 AAQS of 365 ug/m^3 and more stringent state 24-hour AAQS for SO_2 of 260 ug/m^3. Therefore, this analysis shows the change from the GE

Table 6-2

Interacting Source Inventory List

Source Name	Location UTM-E km	Location UTM-N km	SO_2 Emission Rate g/s	Stack Height ft	Stack Diameter ft	Stack Gas Temperature F	Stack Gas Flow Volume acfm
OUC-SEC #1	483.5	3150.6	625.3	550	19	127	1,202,867
OUC-SEC #2	483.5	3150.6	625.3	550	19	127	1,202,867
FPL-CC (#1,2)	522.9	3148.9	2,494.8	397	18.7	275	975,000
NASA-KSC	534.0	3162.0	6.4	35	2.2	497	8,947
OUC-IR #1	521.3	3151.7	288.4	300	14	325	795,323
OUC-IR #2	521.3	3151.7	720.1	300	14	325	795,323
OUC-IR #3	521.3	3151.7	1,056.4	300	14.1	340	1,004,045

combustion turbines to the larger Westinghouse units will not cause or contribute to an exceedance of any applicable AAQS.

6.4.3 PSD Increment Analysis

PSD regulations were developed as a result of the 1977 Clean Air Act Amendments to ensure that air quality does not significantly deteriorate in area currently meeting the AAQSs. At this time PM (TSP), SO_2, and NO_2 are the only pollutants for which PSD increments have been defined. PSD guidelines require an analysis of the consumption of PSD increment if PM (TSP), SO_2, or NO_2 impacts are greater than the PSD significant ambient air quality impact levels.

Air dispersion modeling of the four combustion turbines demonstrated that the predicted 24-hour SO_2 impacts will be above PSD significant impact levels at two receptor locations beyond the plant fenceline. NO_x, and PM impacts are predicted to remain below PSD significant impact levels.

ISCST dispersion modeling was performed to compare the combined impacts of the four combustion turbines and the two OUC-SEC PSD sources with the 24-hour Class II PSD increment for SO_2. The analysis was performed at the two receptors where significant 24-hour SO_2 impacts were found. All five years of meteorological data were conservatively modeled, although the significant impacts only occurred during one year of the modeling.

The results of the combined SO_2 PSD increment consumption analysis showed the four combustion turbines plus the OUC-SEC PSD source consumes 15.5 ug/m^3 or 17 percent of the total 24-hour SO_2 PSD increment of 91 ug/m^3. Therefore, the Project will not cause or contribute to an exceedance of the 24-hour SO_2 PSD increment consumption requirements.

6.5 Toxic Air Pollutants

An analysis was conducted to assess the toxic air pollutant impacts resulting from the four combustion turbines. The emission factors for the toxic pollutants were obtained from the EPA document, Toxic Air Pollutant Emission Factors -- A compilation for Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a), and are expressed in units of lb/MBtu. A nominal emission rate (in g/s) equivalent to a 1 lb/MBtu pollutant emission factor was modeled for the four combustion turbines. The resultant impacts were derived by multiplying the nominal modeled impacts by the pollutant emission factors.

The impacts for each of the toxic air pollutants emitted by the combustion turbines were compared to the FDER-provided acceptable ambient concentrations (AAC) and de minimis monitoring criteria. The toxic air pollutant impacts, the AAC, and the de minimis ambient air monitoring concentrations are given in Table 6-3. As shown, the impacts of all toxic pollutants emitted by the Project will be much less than the corresponding AAC and the de minimis monitoring concentrations. Therefore, no further modeling analysis or preconstruction monitoring is necessary for the toxic pollutants.

Table 6-3

Toxic Pollutant Emissions and Air Quality Impacts

Pollutant	Emission Factor lb/MBtu	Averaging Period	Resultant Ambient Impact ug/m^3	Acceptable Ambient Concentrations ug/m^3	De Minimis Monitoring Criteria ug/m^3
Arsenic	4.2E-6	8-Hour	1.4E-4	2.0	--
		24-Hour	7.5E-5	0.5	--
		Annual	5.04E-6	0.0002	--
Beryllium	2.5E-6	8-Hour	8.1E-5	0.02	--
		24-Hour	4.5E-5	0.005	0.001
		Annual	3.0E-6	0.0004	--
Benzene[a]	7.1E-4	8-Hour	2.3E-2	30	--
		24-Hour	1.3E-2	7.1	--
		Annual	8.5E-4	0.12	--
Cadmium	1.1E-5	8-Hour	3.6E-4	0.5	--
		24-Hour	2.0E-4	0.12	--
		Annual	1.3E-5	0.0006	--
Chromium	4.8E-5	8-Hour	1.6E-3	0.5	--
		24-Hour	8.5E-4	0.12	--
Copper	2.8E-4	8-Hour	9.1E-3	10	--
		24-Hour	5.0E-3	2.4	--
Formaldehyde	4.1E-4	Annual	4.9E-4	0.08	--
Lead	8.9E-6	8-Hour	2.9E-4	1.5	--
		24-Hour	1.6E-4	0.36	0.1[b]
		Annual	1.1E-5	0.09	--

Table 6-3

Toxic Pollutant Emissions and Air Quality Impacts

Pollutant	Emission Factor lb/MBtu	Averaging Period	Resultant Ambient Impact ug/m^3	Acceptable Ambient Concentrations ug/m^3	De Minimis Monitoring Criteria ug/m^3
Manganese	2.6E-5	8-Hour	8.5E-4	50	--
		24-Hour	4.6E-4	12	--
Mercury	3.0E-6	8-Hour	9.8E-5	0.1	--
		24-Hour	5.3E-5	0.024	0.25
Nickel	1.7E-4	8-Hour	5.5E-3	0.5	--
		24-Hour	3.0E-3	0.12	--
		Annual	2.0E-4	0.004	--

(a) For natural gas combustion only.
(b) Quarterly average.

7.0 Additional Impact Analysis

PSD regulations require that Project impacts on visibility, soils and vegetation, and growth also be examined.

7.1 Visibility

The nearest PSD Class I area is the Chassahowitz Wilderness Area located along the west coast of Florida, approximately 175 kilometers from the Project site. A screening Level-1 visibility analysis was performed for the PSD Class I area. Emission rates for the four turbines firing fuel oil at base load were used with the EPA-approved VISCREEN model to determine the Project's maximum visual impacts. The results of the analysis are given in Table 7-1.

The maximum visual impacts were compared to the visual criteria for assessing plume contrast and Delta E. Delta E is a color difference parameter developed to specify the perceived magnitude of changes in the color and brightness of the sky due to the plume. The analysis demonstrated that the Project's visual impacts are well below the criteria levels.

7.2 Soils and Vegetation

Simple cycle combustion turbine projects are typically considered "clean facilities" that result in very low predicted ground-level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust.

As a result of the low pollutant emission rates and effective pollutant dispersion characteristics, the project impacts on soils and vegetation will be minimal.

7.3 Growth

Economic, population, industrial, and other types of growth are occurring in the vicinity of the Indian River plant. The associated growth cannot be directly attributed to growth induced by the operation of the new combustion

Table 7-1

Visual Effects Screening Analysis for
Source: OUC INDIAN RIVER
Class I Area: CHASSAHOWITZ WILDERNESS

*** Level-1 Screening ***

Input Emissions for

Particulates	33.40	G	/S
NOx (as NO2)	95.40	G	/S
Primary NO2	.00	G	/S
Soot	.00	G	/S
Primary SO4	.00	G	/S

**** Default Particle Characteri

Transport Scenario Speci

Background Ozone:	. ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	175.00 km
Min. Source-Class I Distance:	175.00 km
Max. Source-Class I Distance:	190.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

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

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	175.0	84.	2.00	.013	.05	.000
SKY	140.	84.	175.0	84.	2.00	.002	.05	-.000
TERRAIN	10.	84.	175.0	84.	2.00	.000	.05	.000
TERRAIN	140.	84.	175.0	84.	2.00	.000	.05	.000

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

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	169.4	94.	2.00	.013	.05	.000
SKY	140.	75.	169.4	94.	2.00	.003	.05	-.000
TERRAIN	10.	65.	163.3	104.	2.00	.000	.05	.000
TERRAIN	140.	65.	163.3	104.	2.00	.000	.05	.000

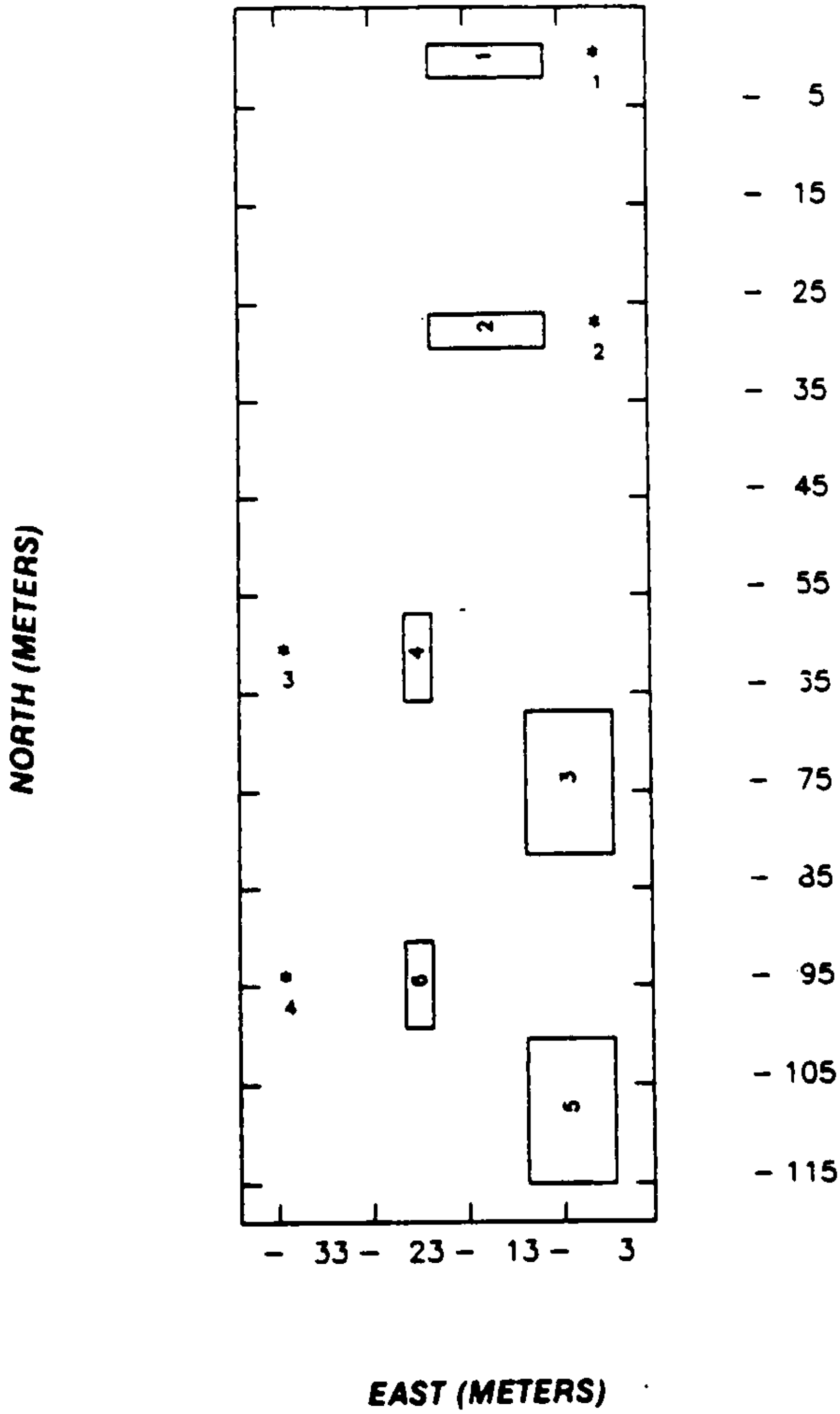
turbines. Therefore, the addition of the combustion turbines is not expected to induce any secondary growth in the surrounding area.

Appendix A

GEP ANALYSIS

OUC INDIAN RIVER

BUILDING DOWNWASH ANALYSIS



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1                         RBRZWAKE
                          IBM-PC VERSION (2.0 )
                          (C) COPYRIGHT 1989, TRINITY CONSULTANTS, INC.
                          SERIAL NUMBER 6440 SOLD TO BLACK & VEATCH CONSULTING ENG
                          RUN NAME: OUCIRS
                          RUN BEGAN ON 02-22-91 AT 17:01:19
1
 NUMBER OF SOURCES =   4

 THE FOLLOWING OPTIONS HAVE BEEN CHOSEN:
 CALCULATIONS ARE MADE FOR THE ISCST MODEL.
 ALL STACKS MUST BE WITHIN 5L TO BE CONSIDERED FOR DIRECTION SPECIFIC DOWNWASH
 DOWNWASH IS CALCULATED IN 36 RADIAL DIRECTIONS.

 BUILDINGS ARE COMBINED REPEATEDLY.

                              ALGORITHMS:
                      ---------------------------
                      0 = NO DOWNWASH
                      1 = HUBER-SNYDER DOWNWASH
                      2 = SCHULMAN-SCIRE DOWNWASH
1                     ---------------------------
```

INPUT BUILDINGS

DESCRIPTION	BLDG #	BLDG HT(M)	# OF CORNERS	X(M)	Y(M)
GE-1 DUCT WORK	1	8.53	4		
				-4.58	1.68
				-16.77	1.68
				-16.77	-1.68
				-4.58	-1.68
GE-2 DUCT WORK	2	8.53	4		
				-4.57	-25.75
				-16.75	-25.75
				-16.75	-29.11
				-4.57	-29.11
WH-1 AIR INLET	3	12.19	4		
				2.29	-66.45
				-6.93	-66.45
				-6.93	-81.08
				2.29	-81.08
WH-1 AIR DUCT	4	7.70	4		
				-19.66	-56.54
				-16.78	-56.54
				-16.78	-65.38
				-19.66	-65.38
WH-2 AIR INLET	5	12.19	4		
				2.30	-99.97
				-6.92	-99.97
				-6.92	-114.60
				2.30	-114.60
WH-2 AIR DUCT	6	7.70	4		
				-19.65	-90.07
				-16.79	-90.07
				-16.79	-98.91
				-19.65	-98.91

COMBINED BUILDINGS

STRUCTURE 1 HAS A HEIGHT 12.19 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
BUILDING # 3: WH-1 AIR INLET

STRUCTURE 2 HAS A HEIGHT 12.19 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
BUILDING # 5: WH-2 AIR INLET

STRUCTURE 3 HAS A HEIGHT 8.53 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
BUILDING # 1: GE-1 DUCT WORK

STRUCTURE 4 HAS A HEIGHT 8.53 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
BUILDING # 2: GE-2 DUCT WORK

STRUCTURE 5 HAS A HEIGHT 7.70 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
BUILDING # 3: WH-1 AIR INLET
BUILDING # 4: WH-1 AIR DUCT

STRUCTURE 6 HAS A HEIGHT 7.70 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
BUILDING # 5: WH-2 AIR INLET
BUILDING # 6: WH-2 AIR DUCT

1

INPUT STACKS

STACK ID #	STACK #	STACK HT(M)	X(M)	Y(M)
1	1	10.97	.00	.00
2	2	10.97	.00	-27.43
3	3	15.24	-33.08	-60.96
4	4	15.24	-33.08	-94.49

1 STACK ID # 1, STACK # 1

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 3 H= 8.53 W= 12.64 GEP= 21.34

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	3	8.53	12.59	21.34	2
20	3	8.53	12.60	21.34	2
30	3	8.53	12.23	21.34	2
40	3	8.53	11.49	21.34	2
50	3	8.53	10.40	21.34	2
60	3	8.53	9.00	21.34	2
70	3	8.53	7.32	19.51	2
80	3	8.53	5.42	16.66	2
90	3	8.53	3.35	13.56	1
100	3	8.53	5.42	16.66	2
110	3	8.53	7.32	19.51	2
120	3	8.53	9.00	21.34	2
130	3	8.53	10.40	21.34	2
140	3	8.53	11.49	21.34	2
150	3	8.53	12.23	21.34	2
160	3	8.53	12.60	21.34	2
170	3	8.53	12.59	21.34	2
180	0	.00	.00	.00	0
190	3	8.53	12.59	21.34	2
200	3	8.53	12.60	21.34	2
210	3	8.53	12.23	21.34	2
220	3	8.53	11.49	21.34	2
230	3	8.53	10.40	21.34	2
240	3	8.53	9.00	21.34	2
250	3	8.53	7.32	19.51	2
260	3	8.53	5.42	16.66	2
270	3	8.53	3.35	13.56	1
280	3	8.53	5.42	16.66	2
290	3	8.53	7.32	19.51	2
300	3	8.53	9.00	21.34	2
310	3	8.53	10.40	21.34	2
320	3	8.53	11.49	21.34	2
330	3	8.53	12.23	21.34	2
340	3	8.53	12.60	21.34	2
350	3	8.53	12.59	21.34	2
360	0	.00	.00	.00	0

1 STACK ID # 2, STACK # 2

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 12.19 W= 17.29 GEP= 30.48

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	1	12.19	11.62	29.62	2
20	4	8.53	12.59	21.34	2
30	4	8.53	12.23	21.34	2
40	4	8.53	11.49	21.34	2
50	4	8.53	10.40	21.34	2
60	4	8.53	9.00	21.34	2
70	4	8.53	7.32	19.52	2
80	4	8.53	5.42	16.67	2
90	4	8.53	3.36	13.57	1
100	4	8.53	5.42	16.67	2
110	4	8.53	7.32	19.52	2
120	4	8.53	9.00	21.34	2
130	4	8.53	10.40	21.34	2
140	3	8.53	11.49	21.34	2
150	3	8.53	12.23	21.34	2
160	3	8.53	12.60	21.34	2
170	3	8.53	12.59	21.34	2
180	0	.00	.00	.00	0
190	4	8.53	12.58	21.34	2
200	4	8.53	12.59	21.34	2
210	4	8.53	12.23	21.34	2
220	4	8.53	11.49	21.34	2
230	4	8.53	10.40	21.34	2
240	4	8.53	9.00	21.34	2
250	4	8.53	7.32	19.52	2
260	4	8.53	5.42	16.67	2
270	4	8.53	3.36	13.57	1
280	4	8.53	5.42	16.67	2
290	4	8.53	7.32	19.52	2
300	4	8.53	9.00	21.34	2
310	4	8.53	10.40	21.34	2
320	4	8.53	11.49	21.34	2
330	4	8.53	12.23	21.34	2
340	4	8.53	12.59	21.34	2
350	1	12.19	11.62	29.62	2
360	1	12.19	9.22	26.02	2

1 STACK ID # 3, STACK # 3

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 12.19 W= 17.29 GEP= 30.48

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	0	.00	.00	.00	0
20	0	.00	.00	.00	0
30	0	.00	.00	.00	0
40	0	.00	.00	.00	0
50	0	.00	.00	.00	0
60	5	7.70	32.23	19.25	1
70	5	7.70	30.57	19.25	1
80	5	7.70	27.98	19.25	1
90	5	7.70	24.54	19.25	1
100	5	7.70	22.46	19.25	1
110	5	7.70	19.69	19.25	1
120	5	7.70	17.28	19.25	1
130	1	12.19	17.13	30.48	2
140	0	.00	.00	.00	0
150	0	.00	.00	.00	0
160	0	.00	.00	.00	0
170	0	.00	.00	.00	0
180	0	.00	.00	.00	0
190	0	.00	.00	.00	0
200	4	8.53	12.59	21.34	1
210	4	8.53	12.23	21.34	1
220	4	8.53	11.49	21.34	1
230	0	.00	.00	.00	0
240	5	7.70	32.23	19.25	1
250	5	7.70	30.57	19.25	1
260	5	7.70	27.98	19.25	1
270	1	12.19	14.63	30.48	2
280	1	12.19	16.01	30.48	2
290	1	12.19	16.90	30.48	2
300	1	12.19	17.28	30.48	2
310	1	12.19	17.13	30.48	2
320	2	12.19	16.47	30.48	2
330	2	12.19	15.30	30.48	2
340	6	7.70	20.26	19.25	1
350	0	.00	.00	.00	0
360	0	.00	.00	.00	0

1 STACK ID # 4, STACK # 4

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 12.19 W= 17.29 GEP= 30.48

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	0	.00	.00	.00	0
20	0	.00	.00	.00	0
30	0	.00	.00	.00	0
40	0	.00	.00	.00	0
50	0	.00	.00	.00	0
60	6	7.70	32.22	19.25	1
70	6	7.70	30.56	19.25	1
80	6	7.70	27.97	19.25	1
90	6	7.70	24.53	19.25	1
100	6	7.70	22.44	19.25	1
110	6	7.70	19.67	19.25	1
120	6	7.70	17.28	19.25	1
130	2	12.19	17.13	30.48	2
140	0	.00	.00	.00	0
150	0	.00	.00	.00	0
160	0	.00	.00	.00	0
170	0	.00	.00	.00	0
180	0	.00	.00	.00	0
190	0	.00	.00	.00	0
200	5	7.70	29.02	19.25	1
210	5	7.70	31.28	19.25	1
220	1	12.19	16.47	30.48	2
230	1	12.19	17.13	30.48	2
240	1	12.19	17.28	30.48	2
250	1	12.19	16.90	30.48	2
260	6	7.70	27.97	19.25	1
270	2	12.19	14.63	30.48	2
280	2	12.19	16.01	30.48	2
290	2	12.19	16.90	30.48	2
300	2	12.19	17.28	30.48	2
310	2	12.19	17.13	30.48	2
320	0	.00	.00	.00	0
330	0	.00	.00	.00	0
340	0	.00	.00	.00	0
350	0	.00	.00	.00	0
360	0	.00	.00	.00	0

```
1
                              STACK #    1
STACK ID:   1,     BUILDING HEIGHT:    8.53,    BUILDING WIDTH:   12.64
   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53
   8.53   8.53   8.53   8.53   8.53    .00   8.53   8.53   8.53   8.53   8.53   8.53
   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53    .00
  12.59  12.60  12.23  11.49  10.40   9.00   7.32   5.42   3.35   5.42   7.32   9.00
  10.40  11.49  12.23  12.60  12.59    .00  12.59  12.60  12.23  11.49  10.40   9.00
   7.32   5.42   3.35   5.42   7.32   9.00  10.40  11.49  12.23  12.60  12.59    .00
                              STACK #    2
STACK ID:   2,     BUILDING HEIGHT:   12.19,    BUILDING WIDTH:   17.29
  12.19   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53
   8.53   8.53   8.53   8.53   8.53    .00   8.53   8.53   8.53   8.53   8.53   8.53
   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53   8.53  12.19  12.19
  11.62  12.59  12.23  11.49  10.40   9.00   7.32   5.42   3.36   5.42   7.32   9.00
  10.40  11.49  12.23  12.60  12.59    .00  12.58  12.59  12.23  11.49  10.40   9.00
   7.32   5.42   3.36   5.42   7.32   9.00  10.40  11.49  12.23  12.59  11.62   9.22
                              STACK #    3
STACK ID:   3,     BUILDING HEIGHT:   12.19,    BUILDING WIDTH:   17.29
    .00    .00    .00    .00    .00   7.70   7.70   7.70   7.70   7.70   7.70   7.70
  12.19    .00    .00    .00    .00    .00    .00   8.53   8.53   8.53    .00   7.70
   7.70   7.70  12.19  12.19  12.19  12.19  12.19  12.19  12.19   7.70    .00    .00
    .00    .00    .00    .00    .00  32.23  30.57  27.98  24.54  22.46  19.69  17.28
  17.13    .00    .00    .00    .00    .00    .00  12.59  12.23  11.49    .00  32.23
  30.57  27.98  14.63  16.01  16.90  17.28  17.13  16.47  15.30  20.26    .00    .00
                              STACK #    4
STACK ID:   4,     BUILDING HEIGHT:   12.19,    BUILDING WIDTH:   17.29
    .00    .00    .00    .00    .00   7.70   7.70   7.70   7.70   7.70   7.70   7.70
  12.19    .00    .00    .00    .00    .00    .00   7.70   7.70  12.19  12.19  12.19
  12.19   7.70  12.19  12.19  12.19  12.19  12.19    .00    .00    .00    .00    .00
    .00    .00    .00    .00    .00  32.22  30.56  27.97  24.53  22.44  19.67  17.28
  17.13    .00    .00    .00    .00    .00    .00  29.02  31.28  16.47  17.13  17.28
  16.90  27.97  14.63  16.01  16.90  17.28  17.13    .00    .00    .00    .00    .00
1                        RUN ENDED ON 02-22-91 AT 17:01:22
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Appendix B

MODELING RUN LISTING

ARCHIVE LISTING OF OUC INDIAN RIVER AIR DISPERSION MODELING RUNS

File	Pollutant	Type	Year	Model	Receptors	Comments
OUCC1P.LST	S02	SIA	1981	ISCST	100M - 20 KM	SIGNIFICANT IMPACT
OUCC2P.LST	S02	SIA	1982	ISCST	100M - 20 KM	DETERMINATION FOR
OUCC3P.LST	S02	SIA	1983	ISCST	100M - 20 KM	S02. (NOX AND TSP
OUCC4P.LST	S02	SIA	1984	ISCST	100M - 20 KM	IMPACTS DETERMINED
OUCC5P.LST	S02	SIA	1985	ISCST	100M - 20 KM	FROM RESULTS).
OUCCO1P.LST	CO	SIA	1981	ISCST	100M - 20 KM	SIGNIFICANT IMPACT
OUCCO2P.LST	CO	SIA	1982	ISCST	100M - 20 KM	DETERMINATION FOR
OUCCO3P.LST	CO	SIA	1983	ISCST	100M - 20 KM	CO.
OUCCO4P.LST	CO	SIA	1984	ISCST	100M - 20 KM	
OUCCO5P.LST	CO	SIA	1985	ISCST	100M - 20 KM	
PTOXIC1.LST	TOXIC	TLV	1981	ISCST	100M - 20 KM	TOXIC POLLUTANT
PTOXIC2.LST	TOXIC	TLV	1982	ISCST	100M - 20 KM	IMPACT COMPARISON
PTOXIC3.LST	TOXIC	TLV	1983	ISCST	100M - 20 KM	TO TLVs AND OTHER
PTOXIC4.LST	TOXIC	TLV	1984	ISCST	100M - 20 KM	FDER ACCEPTABLE
PTOXIC5.LST	TOXIC	TLV	1985	ISCST	100M - 20 KM	LEVELS.
NQS11P.LST	S02	NAAQS	1981	ISCST	2 DISCRETE	BASED ON INVENTORY
NQS12P.LST	S02	NAAQS	1982	ISCST	2 DISCRETE	PROVIDED BY FDER
NQS13P.LST	S02	NAAQS	1983	ISCST	2 DISCRETE	
NQS14P.LST	S02	NAAQS	1984	ISCST	2 DISCRETE	
NQS15P.LST	S02	NAAQS	1985	ISCST	2 DISCRETE	
PSD11P.LST	S02	PSD	1981	ISCST	2 DISCRETE	BASED ON INVENTORY
PSD12P.LST	S02	PSD	1982	ISCST	2 DISCRETE	PROVIDED BY FDER
PSD13P.LST	S02	PSD	1983	ISCST	2 DISCRETE	
PSD14P.LST	S02	PSD	1984	ISCST	2 DISCRETE	
PSD15P.LST	S02	PSD	1985	ISCST	2 DISCRETE	
OUCCTP.PNT	S02	SIA	--	ISCST	--	SOURCE INPUT FILE USED FOR S02 SIA ANALYSIS
OUCCOP.PNT	CO	SIA	--	ISCST	--	SOURCE INPUT FILE USED FOR CO SIA ANALYSIS
TOXIC.PNT	TOXIC	TLV	--	ISCST	--	SOURCE INPUT FILE USED FOR TOXIC ANALYSIS
OUCNQSP.PNT	S02	NAAQS	--	ISCST	--	SOURCE INPUT FILE USED FOR S02 NAAQS ANALYSIS
OUCPSDP.PNT	S02	PSD	--	ISCST	--	SOURCE INPUT FILE USED FOR S02 PSD ANALYSIS
OUCIR5.BLD	--	SIA	--	ISCST	--	BUILDING DOWNWASH FILE WITH RELATIVE COORDINATES
OUCIR6.BLD	--	NQS/PSD	--	ISCST	--	BUILDING DOWNWASH FILE WITH UTM COORDINATES

INFORMATION ON THE PROGRAMS PKARC.COM AND PKXARC.COM

To conserve disks, computer files are often archived using the PKARC program. This process redistributes data within a file to eliminate formatted space, thus alleviating the storage problems inherent with the large list files.

One or more files may be stored as a single archive file. Likewise, individual files may be retrieved from an archive file.

To retrieve these files the PKARC and PKXARC programs have been included on a disk. To view the name of the files contained in an archive file, you will need to enter PKARC V XXXXX.ARC where XXXXX is the archive file name. The various archive names and related information are provided on the enclosed log sheet. To retrieve all files from a single archive file, type PKXARC XXXXX.ARC *.*. This not only produces files that can be accessed to view or print, but also leaves the archive file intact. The retrieved files will have the same names as the file names in the archive file. An individual file may be retrieved from an archive file by typing PKXARC XXXXX.ARC xxxxx.lst. Where xxxxx is the file name. Additional information about the PKARC program is available by typing PKARC.