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December 27, 1991

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

Re: Orlando CoGen Limited, L.P. Project
Orange County, FL

Dear Mr. Fancy:

Please find enclosed on behalf of Orlando CoGen Limited, L.P., four signed and sealed air construction permit application forms for a gas turbine cogeneration facility. Also enclosed is the application fee of $7,500. The proposed facility will be located in Orlando, Florida (Orange County). KBN Engineering and Applied Sciences, Inc. has assisted Orlando CoGen in preparing the permit application. If you have any questions concerning our submittal, please call me at (904) 331-9000, of Gary Kinsey at (215) 481-4029.

We look forward to working with you on this project.

Sincerely,

David A. Buff

David A. Buff, M.E., P.E.
Principal Engineer

DAB/dmpm

Enclosure

cc: Gary Kinsey

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DEC 30 1991
Division of Air
Resources Management

91134C2/1

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

196679 Air Products and Chemicals, Inc.
Allentown, PA 18195

AIR PRODUCTS

12 13 91
DATE OF ISSUE

309454
VENDOR CODE

****$7,500.00**

PAY TO THE ORDER OF
FLORIDA DEPARTMENT OF ENVIR
REGULATION
N
N N

L. Baker
White

CITIBANK DELAWARE
ONE PENN'S WAY
NEW CASTLE, DE 19720

62-20
311

[redacted]

Re: Orlando CoGen Limited, L.P. Project
Orange County, FL

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00/031

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91134C2/1

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

PSD PERMIT APPLICATION FOR ORLANDO COGEN LIMITED, L.P. COGENERATION PROJECT

Prepared For:

Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Prepared By:

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

December 1991
91134C1

PART A

AIR CONSTRUCTION PERMIT APPLICATION FORM

12-30-91
Rc.# 180729

AC 48-206720
PSD-FL-184

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Facility* ☒ New[1] ☐ Existing[1]

APPLICATION TYPE: ☒ Construction ☐ Operation ☐ Modification

COMPANY NAME: *Orlando CoGen Limited, L.P.* COUNTY: *Orange*

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) *HRSG Stack*

SOURCE LOCATION: Street *Orlando Central Park* City *Orlando*

UTM: East *459.50* North *3,146.10*

Latitude *28* ° *26* ' *23* "N Longitude *81* ° *24* ' *28* "W

APPLICANT NAME AND TITLE: *Orlando CoGen Limited, L.P.*

APPLICANT ADDRESS: *7201 Hamilton Boulevard, Allentown, PA 18195-1501*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Orlando CoGen Limited, L.P.*

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

*Attach letter of authorization

Signed: ____________________

John P. Jones, President, Orlando CoGen (I), Inc., General Partner of Orlando CoGen Limited, L.P.
Name and Title (Please Type)

Date: ____________ Telephone No. *(215) 481-4911*

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

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

---

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

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

Signed ______________________

David A. Buff
Name (Please Type)

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

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

Florida Registration No. *19011* Date:____________ Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

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

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

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

Start of Construction *June 1992* Completion of Construction *June 1, 1994*

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

The cost of control is integral to the design of the project. Dry low NO_x combustion technology and natural gas will be used to reduce air pollutant emissions.

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

No previous DER permits.

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

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

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

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

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable. ***PSD Permit Application is Attached.***

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

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

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

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

1. Total Process Input Rate (lbs/hr): *Not Applicable*

2. Product Weight (lbs/hr): *Not Applicable*

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

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*2.96*	*12.35*	*NA*	*NA*	*2.96*	*12.35*	*See*
PM	*11.00*	*48.18*	*NA*	*NA*	*11.0*	*48.18*	*Figure*
NO_x	*98.6*	*419.2*	*94 ppmvd*		*98.6*	*419.2*	*2-1 in*
CO	*33.2*	*114.6*	*NA*	*NA*	*33.2*	*114.6*	*PSD*
VOC	*6.7*	*19.75*	*NA*	*NA*	*6.7*	*19.75*	*Appl.*

[1] See Section V, Item 2. ***Presents maximum based on either 20°F operation or combined CT and duct firing.***

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input) ***NSPS - 75 ppmvd NO_x corrected to 15% O_2 and heat rate at ISO conditions. FDER Rule 17-2.660.***

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated with~~out~~ control (See Section V, Item 3).

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

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

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

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas (CT)	*0.906 (59°F)*	*0.987 (20°F)*	*933.9 at 20°F*
Natural Gas (Duct Burner)	*0.106*[a]	*0.129*	*122.0*

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.
[a]*Based on burning only natural gas for 4,500 hours/year @ 100 x 10^6Btu/hr*

Fuel Analysis:

Percent Sulfur: *1 grain/100 cubic feet (CF) of gas* Percent Ash: *Negligible*

Density: ______ lbs/gal Typical Percent Nitrogen: *Negligible*

Heat Capacity: *946 Btu/CF; 20,877* BTU/lb *NA* BTU/gal

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

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

Annual Average *Not Applicable* Maximum ______

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

All wastewaters generated from the plant will be discharged to the Orange County Wastewater treatment POTW facility at Sandlake Road.

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

Stack Height: *115* ft. Stack Diameter: *15.7* ft.

Gas Flow Rate: *675,048* ACFM *475,933* DSCFM Gas Exit Temperature: *220* °F.

Water Vapor Content: *9.2* % Velocity: *58.14* FPS

See Table 2-1 in PSD application; CT/DB exhaust at 90°F shown. These parameters used in air modeling.

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type 0 (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

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

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

Manufacturer ______

Date Constructed ______ Model No. ______

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

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

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

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

Type of pollution control devices: ☐ Cyclone ☐ Wet Scrubber ☐ Afterburner
☐ Other (specify) ______

Brief description of operating characteristics of control devices: ______________

____

____

____

____

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

____

____

____

____

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

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   See Table A-1 in PSD Application
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Appendix A in PSD Application
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Appendix A in PSD Application
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Section 4.0 in PSD Application
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See Appendix A in PSD Application
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-1 in PSD Application
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD Application
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See map pocket in PSD Application

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

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

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

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

[x] Yes [ ] No

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

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

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

Contaminant	Rate or Concentration

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

Contaminant	Rate or Concentration
NO_x	*25 ppmvd corrected to 15% O_2*
CO	*10 ppmvd from CT; 16 ppmvd from CT/Duct Burner*
VOC	*3 ppmvd*
See Section 4.0 in PSD Application	*for other pollutants*

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

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

*Explain method of determining

See Section 4.0 in PSD Application

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

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

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

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

3.

a. Control Device: b. Operating Principles:

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

e. Useful Life: f. Operating Cost:

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

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

4.

a. Control Device: b. Operating Principles:

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

e. Useful Life: f. Operating Cost:

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

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

F. Describe the control technology selected:

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

3. Capital Cost: 4. Useful Life:

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

7. Maintenance Cost: 8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

---

[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

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

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Sections 3.4.2.2 and 5.2 in PSD Application

A. Company Monitored Data

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

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

Other data recorded ______________________________

Attach all data or statistical summaries to this application.

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

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

☐ Yes ☐ No ☐ Unknown

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

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

2. Surface data obtained from (location)________________________________

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

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

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

1. ________________________________ Modified? If yes, attach description.

2. ________________________________ Modified? If yes, attach description.

3. ________________________________ Modified? If yes, attach description.

4. ________________________________ Modified? If yes, attach description.

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

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

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

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

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

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

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

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

PART B

PSD REPORT

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APPENDIX A

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LIST OF FIGURES

ACRONYMS AND ABBREVIATIONS

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AAQS	Ambient Air Quality Standards
ABB	Asea Brown Boveri
BACT	best available control technology
10^6 Btu/hr	million British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
Btu/yr	British thermal units per year
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FGD	flue gas desulfurization
ft	foot/feet
ft^3/yr	cubic feet per year
GEP	good engineering practice
gr/scf	grains per standard cubic feet
g/s	grams per second
H_2SO_4	sulfuric acid
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term
ISCST	Industrial Source Complex Short-Term
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
kWh/hr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia

ACRONYMS AND ABBREVIATIONS

(Page 2 of 2)

NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service
PM(TSP)	total suspended particulate matter
PM10	particulate matter less than or equal to 10 micrometers
ppm	parts per million
ppmvd	parts per million volume, dry
PSD	prevention of significant deterioration
RCRA	Resource Conservation and Recovery Act
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective noncatalytic reduction
SO_2	sulfuric dioxide
TPH	tons per hour
TPY	tons per year
$\mu g/m^3$	micrograms per cubic meter
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound

1.0 INTRODUCTION

Orlando CoGen Limited, L.P. is proposing to locate a natural gas-fired, 128.9-megawatt (MW) nominal capacity, cogeneration facility in the Orlando Central Park. The proposed site, which is located in Orange County (Figure 1-1), will be under the control of Orlando CoGen Limited, L.P.. The proposed cogeneration facility will consist of one combustion turbine (CT) and a steam turbine, which will utilize the steam generated by a heat recovery steam generator (HRSG). Operational characteristics for the facility are provided in Table 1-1. The HRSG also will supply steam an adsorption chiller system, which will be used to supply chilled water service to the existing Air Products and Chemicals plant located adjacent to the site. A plot plan for the cogeneration facility is contained in the map pocket.

KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted by Orlando CoGen Limited, L.P. to provide air permitting services for the facility. The prevention of significant deterioration (PSD) review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses. Initially, preliminary analyses were performed to determine compliance with PSD increments and preconstruction de minimis monitoring levels for the proposed plant only. This analysis demonstrated that the proposed facility will have insignificant air quality impacts.

The proposed project will be a major facility because potential emissions of at least one regulated pollutant exceed 250 tons per year (TPY). PSD review is required for such pollutants and for any other regulated pollutant for which the potential emissions exceed the PSD significant emission rate. The potential emissions from the proposed project will exceed the PSD significant emission rates for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), and particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM10). Therefore, the project is subject to PSD review for these pollutants.

This report is presented in seven sections. A general description of the proposed operation is given in Section 2.0. The air quality review requirements and applicability of the PSD and nonattainment regulations to the project are presented in Section 3.0. The control technology

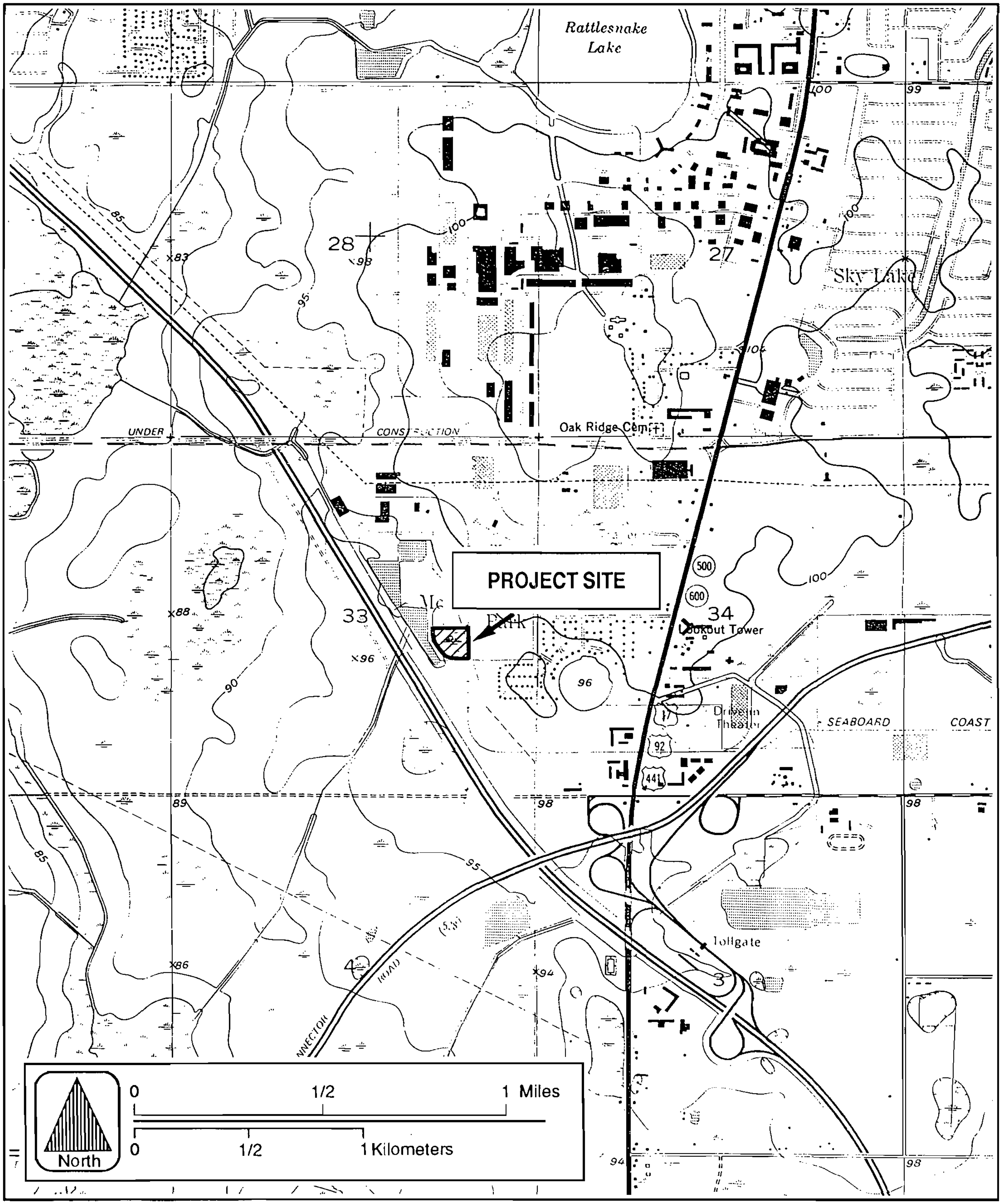


Figure 1-1. SITE LOCATION MAP, ORLANDO COGEN LIMITED, L.P.

Table 1-1. Characteristics of the Orlando CoGen Limited, L.P. Project

Characteristic	CT Only @ ISO Condition	Design Condition[a]
Net Capacity (kW)		
Combustion Turbine	78,830	78,830
Steam Cycle	35,740	50,100
Total	114,570	128,930
Equipment Characteristics		
Type of CT	ABB 11N-EV	ABB 11N-EV
CT Heat Input (10^6 Btu/hr)	856.9	856.9
Duct Burner Heat Input (10^6 Btu/hr)	--	122.0[b]
CT NO_x Control	Dry Low-NO_x Combustor	
Natural Gas Fuel		
CT (ft^3/hr)	905,795	905,795
Duct Burner (ft^3/hr)	--	128,964[b]

Note:
CT = combustion turbine.
ft^3/hr = cubic feet per hour.
HRSG = heat recovery steam generator.
10^6 Btu/hr = million British thermal units per hour.

[a] At ISO condition (59°F ambient temperature) for CT and maximum duct firing in HRSG.

[b] Duct firing will be implemented at an ambient temperature of 59°F or higher. Maximum heat input will be 122 x 10^6 Btu/hr.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The proposed project will consist of one CT that will exhaust through one HRSG. The CT will be an Asea Brown Boveri (ABB) 11N-EV machine. The ABB 11N-EV is a heavy frame industrial gas turbine that uses a single dry low-NO_x combustion chamber. The CT will be served by a single HRSG, exhausting to an individual stack. There will be no bypass stacks on the CT for simple cycle operation. There will be a single electric generator, which will be driven directly by the CT and a steam turbine. A flow diagram of the project is presented in Figure 2-1.

Natural gas will be used to fuel the CT; distillate fuel oil will not be used. Supplementary firing of only natural gas in the HRSG will occur only when the ambient temperature is 59°F or greater. The supplementary firing is expected to occur during "on-peak" power demand time periods. The maximum duct burner firing will be 4,500 hours at an average heat input of 100 million British thermal units per hour (10^6 Btu/hr), or 450,000 million British thermal units per year (x 10^6 Btu/yr). Maximum duct burner firing will be 122 x 10^6 Btu/hr.

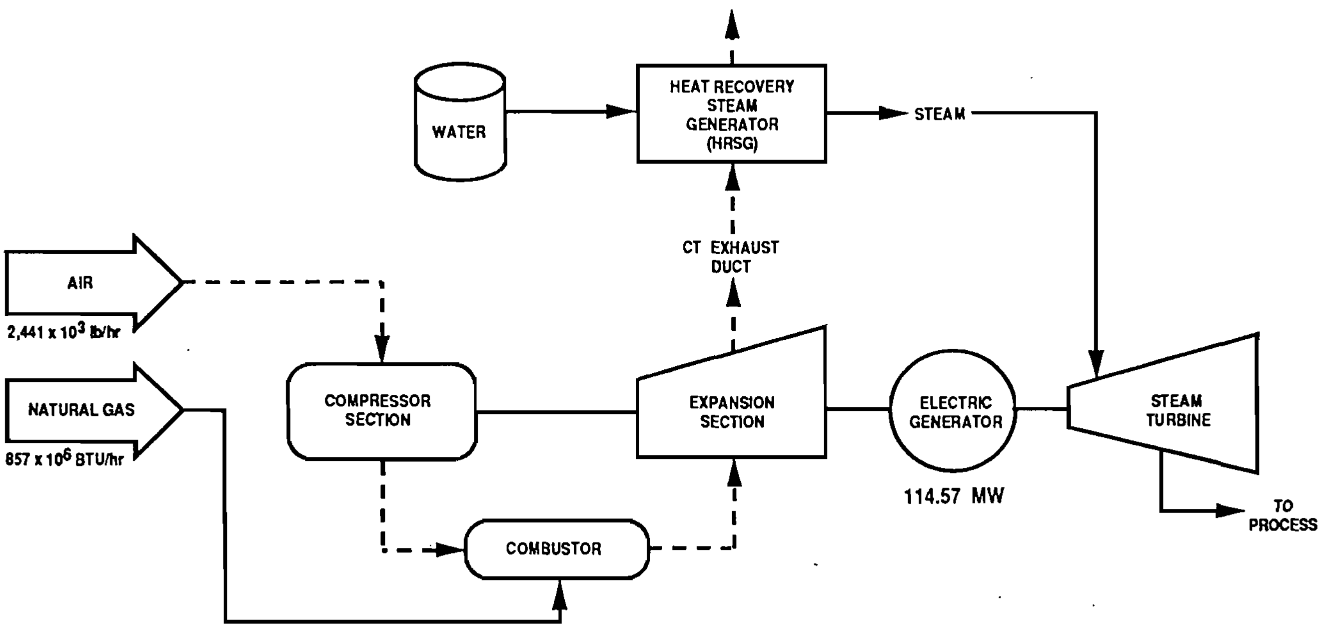
Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Dry low-NO_x combustion will be used to control emissions of NO_x from the CT; low-NO_x burners will minimize NO_x emissions when duct firinyg. The use of natural gas will minimize the emissions of sulfur dioxide (SO_2) and other pollutants from the unit.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

Emissions and stack parameters for the CT/HRSG are presented in Table 2-1. Maximum emissions for the CT occur at the lowest ambient operating temperature [i.e., 20 degrees Fahrenheit (°F)]. Emissions and stack parameters for this case are presented in Table 2-1 for the CT only.

In the case of duct firing, duct firing will occur only at ambient temperatures of 59°F or greater. The maximum heat input to the duct burner will be 122 x 10^6 Btu/hr at a higher ambient temperature. Since the CTs emissions are higher at lower ambient temperatures, the CT

ISO CONDITIONS:



DESIGN CONDITIONS:

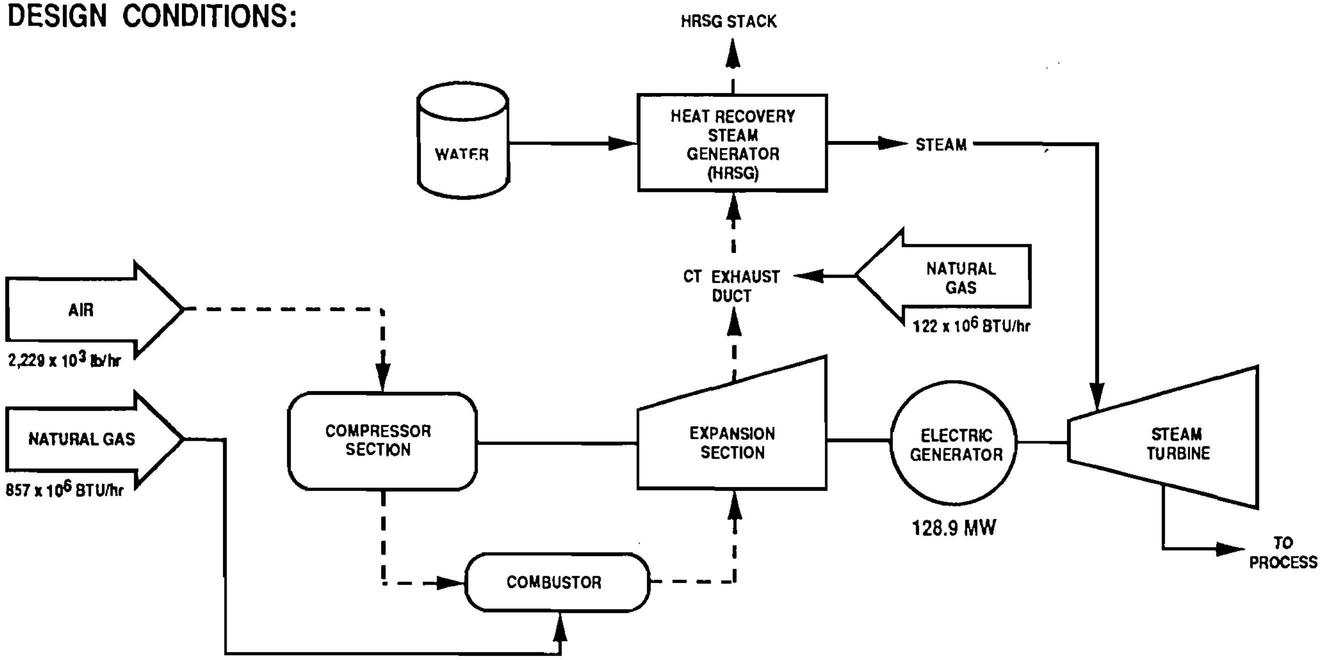


Figure 2-1. SIMPLIFIED FLOW DIAGRAM OF PROPOSED UNIT, ORLANDO COGEN LIMITED, L.P.

KBN

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility

	Maximum Emissions			
		CT/Duct Burner		
Parameter	CT Only[a]	CT[b]	Duct Burner[c]	Total
Stack Data (ft)				
Height	115			115
Diameter	15.7			15.7
Operating Data				
Temperature (°F)	250			220
Velocity (ft/sec)	69.9			58.14
Building Data (ft)				
Height	76			76
Length	60			60
Width	43			43
Maximum Hourly Emissions (lb/hr)				
SO_2	2.82	2.59	0.37	2.96
PM/PM10	11.0	9.0	1.22	10.22
NO_x	95.7	86.4	12.2	98.6
CO	23.3	21.0	12.2	33.2
VOC	3.18	2.98	3.7	6.7
Sulfuric Acid Mist	0.02	0.02	0.003	0.02
Annual Potential Emissions (TPY)				
SO_2	12.35	11.34	0.68	12.02
PM/PM10	48.18	39.42	2.25	41.67
NO_x	419.2	378.4	22.5	400.9
CO	102.1	92.1	22.5	114.6
VOC	13.9	13.0	6.75	19.75
Sulfuric Acid Mist	0.095	0.087	0.01	0.097

Note: 10^6 Btu/hr = million British thermal units per hour.
CO = carbon monoxide.
CT = combustion turbine.
°F = degrees Fahrenheit.
ft = feet.
ft/sec = feet per second.
HRSG = heat recovery steam generators.
lb/hr = pounds per hour.
Neg = negative.
NO_x = nitrogen oxides.
O_2 = oxygen molecule.
PM = particulate matter.
PM10 = particulate matter less than or equal to 10 micrometers.
ppmvd = parts per million by volume dry.
SO_2 = sulfur dioxide.
TPY = tons per year.
VOC = volatile organic compound.

[a] Performance based on 20°F with NO_x emissions at 25 ppmvd (corrected to 15 percent O_2); 8,760 hr/yr operation.

[b] Performance based on 59°F with NO_x emissions of 25 ppmvd (corrected to 15 percent O_2), 8,760 hr/yr operation; stack parameters based on 90°F ambient temperature.

[c] Performance based on 122 x 10^6 Btu/hr heat input for HRSG; annual emissions based on 4,500 hours per year operation at an average heat input of 100 x 10^6 Btu/hr.

3688.5 @ 122x10^6

emissions for the case of duct firing were based on 59°F ambient temperature, with duct firing emissions based on 122 x 10^6 Btu/hr.

These emissions, as well as the total emissions for the CT and duct firing, are shown in Table 2-1. Stack parameters for the duct firing case are based on 90°F ambient temperature, which produces the lowest volume flow and, hence, lowest plume rise of the exhaust gases.

Gas turbine performance data and maximum emissions for regulated criteria pollutants, regulated noncriteria pollutants, and nonregulated pollutants from the CT are presented in Tables A-1 through A-5 of Appendix A.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

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

3.1 NATIONAL AND STATE AAQS

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

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

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

A "major facility" is defined as any one of 28 named source categories that has the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

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

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

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable (i.e., no standard exists).

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

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations

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

[a] Short-term concentrations are not to be exceeded.

[b] No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

[c] Any emission rate of these pollutants.

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

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

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

of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.500, Florida Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

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

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

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated, based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

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

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

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

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

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

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

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

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

3.2.3 CONTROL TECHNOLOGY REVIEW

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

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

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

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

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

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected.

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

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

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

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

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

3.2.5 SOURCE IMPACT ANALYSIS

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

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

3.2.6 ADDITIONAL IMPACT ANALYSIS

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

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

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

1. 65 meters (m), or
2. A height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s), or

3. A height demonstrated by a fluid model or field study.

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

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

3.3 NONATTAINMENT RULES

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

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

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

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

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because potential emissions of at least one regulated pollutant will exceed 250 TPY (refer to Table 2-1); therefore, PSD review is required for any pollutant for which the potential emissions exceed the PSD significant emission rates presented in Table 3-2 (i.e., major source). As shown in Table 3-3, potential emissions from the proposed project will exceed the PSD significant emission rates for NO_x, CO, and PM/PM10. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

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

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

Maximum predicted impacts as a result of the maximum emission associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum impacts are below the respective de minimis monitoring concentration for each pollutant. Therefore, preconstruction monitoring is not required for these pollutants.

3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The proposed stack for the proposed CT/HRSG will be 115 ft (35.1 m) high and, therefore, does not exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0.

3.4.3 NONATTAINMENT REVIEW

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

Table 3-3. Maximum Emissions Due To the Orlando CoGen Limited, L.P. Project Compared to the PSD Significant Emission Rates

	Emissions (TPY)		
Pollutant	Potential Emissions From Proposed Facility	Significant Emission Rate	PSD Review
Sulfur Dioxide	12.35	40	No
Particulate Matter (TSP)	48.18	25	Yes
Particulate Matter (PM10)	48.18	15	Yes
Nitrogen Dioxide	419.2	40	Yes
Carbon Monoxide	114.6	100	Yes
Volatile Organic Compounds	19.75	40	No
Lead	NEG	0.6	No
Sulfuric Acid Mist	0.097	7	No
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Asbestos	NEG	0.007	No
Beryllium	NEG	0.0004	No
Mercury	NEG	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	NEG	0	No

Note: NEG = Negligible.
TPY = Tons per year.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has a draft policy (FDER, 1991) that may be used to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. All regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to No-Threat Levels (NTLs) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered not to pose a significant health risk. Impacts of emissions of hazardous/toxic pollutants from the proposed facility are presented in Section 7.0. Based on this analysis, the NTL will not be exceeded for any pollutant.

Table 3-4. Predicted Maximum Impacts Due To the Orlando CoGen Limited, L.P. Project Compared to PSD *De Minimis* Monitoring Concentrations

Pollutant	Averaging Time	Concentration ($\mu g/m^3$) Predicted Maximum Impact	 *De Minimis* Monitoring Concentration
Particulate Matter (PM10)	24-hour	2.4	10
Nitrogen Dioxide	Annual	0.6	14
Carbon Monoxide	8-hour	12	575

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

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, CO, and PM/PM(10) for the Orlando CoGen project (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analysis is based on the regulatory definitions of BACT, and is consistent with EPA's draft policy requiring a top-down approach.

4.2 NEW SOURCE PERFORMANCE STANDARDS

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

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

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331(q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis. There are no NSPS emission limits for PM/PM10 or CO.

As noted from Table 4-1, the NSPS NO_x emission limit is adjusted based on unit heat rate and to allow for fuel-bound nitrogen (FBN). For a FBN content of 0.015 percent or less, no increase in the NSPS is provided; for a FBN content of between 0.015 and 0.10 percent, the NSPS is increased by the factor of 0.4 times the FBN content (in percent by weight).

For the proposed CT, the NSPS emission limit is 94 parts per million (ppm), corrected to 15 percent oxygen dry conditions. The applicable NSPS for the duct burners is 40 CFR 60, Subpart Db. The applicable requirements are presented in Table 4-2.

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

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

Note: 10^6 Btu/hr = million British thermal units per hour.
O_2 = oxygen molecule.
ppm = parts per million.

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

[b] Standard is multiplied by 14.4/Y, where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

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

Source: 40 CFR 60, Subpart GG.

Table 4-2. Federal NSPS for Natural Gas Fired Industrial Steam-Generating Units, 40 CFR 60, Subpart Db[a]

Pollutant	Emission Limitation for Gaseous or Liquid Fuels
Particulate Matter	No emission limits
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide	No emission limits
Nitrogen Oxides	1) Low heat release rate unit - 0.10 lb/10^6 Btu 2) High heat release rate unit - 0.20 lb/10^6 Btu 3) Duct burner in combined cycle system - 0.20 lb/10^6 Btu

Note: 10^6 Btu/hr = million British thermal units per hour.
lb/10^6 Btu = pound million British thermal units.
% = percent.

[a] Applies to any device that combusts fuel to produce steam and that has a maximum heat input of more than 100 x 10^6 Btu/hr. Sources subject to Subpart Da are not subject to Subpart Db.

Source: 40 CFR 60, Subpart Db.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 NITROGEN OXIDES

4.3.1.1 Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-3 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines. This table was developed from the information contained in the LAER/BACT clearinghouse documents (EPA, 1985b, 1986, 1987c, 1988c, 1989) and by contacting state agencies, such as the California Air Control Board, the South Coast Air Quality Management District, the New Jersey Department of Environmental Protection, and the Rhode Island Department of Environmental Management.

The most stringent NO_x controls for CTs established as LAER/BACT by state agencies are selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. SCR has been installed or permitted in about 132 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About 83 percent (i.e., 109) of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, 43 percent have been in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

Table 4-3. *Summary of BACT Determinations for NOx from Gas-fired Turbines*

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)	Control Method	Eff. (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	25	@ 15% O2	Steam Injection	—
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	25	@ 15% O2	Steam Injection	—
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	—	—	—	42	@ 15% O2	Dry Low NOx Combustor	—
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	—	6.3	—	40	ppmv @ 15% O2	Water Inject 0.67 lb/lb	71.00%
City of Lakeland	FL	Jul-91	Combined Cycle	120 MW	—	—	—	25	@ 15% O2	Dry Low NOx Combustor	—
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	—	—	—	6	@ 15% O2	SCR	90.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	—	—	—	25	@ 15% O2	Dry Low NOx Combustor	—
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	—	139	—	25	ppmvd	H2o Injection & Low NOx Comb.	—
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	—	—	1032	42	ppmvd	Water Injection	—
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	—	—	—	42	@ 15% O2	Wet Injection	—
Salinas River Cogen	CA	Nov-90	Gas Turbine	43.2 MW	—	10	—	6	@ 15% O2	Dry Low NOx Comb. & SCR	—
Sargent Canyon Cogen Co	CA	Nov-90	Gas Turbine	42.5 MW	—	10	—	6	@ 15% O2	Dry Low NOx Comb. & SCR	—
March Point Cogen	WA	Oct-90	Turbine	80 MW	—	—	—	25	@ 15% O2	Massive Steam Injection	80.00%
Las Vegas Cogen	NV	Oct-90	Turbine, Peaking	397 MMBtu/hr	—	—	—	10	ppm	Water Injection & SCR	—
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	0.10	—	—	25	@ 15% O2	Dry Low NOx Combustor	—
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	—	—	—	9	ppmvd	Dry Comb. to 25 ppm, SCR to 9 pp	—
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	—	—	—	36		Water Injection	—
O'Brian California Cogen II	CA	Jan-90	Gas Turbine	49.50 MW	—	114.6	—	—		SCR	—
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	—	—	—	9	@ 15% O2, 1H Av	Water Injection & SCR	80.00%
Richmond Power Enterprise Partn.	VA	Dec-89	Gas Turbine	1,163.5 MMBtu/hr	—	—	—	8.2	@ 15% O2	Steam Inj. & SCR	—
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	—	—	—	25	ppm	Steam Injection	—
Badger Creek Limited	CA	Oct-89	GT-Cogen	457.8 MMBtu/hr	0.0135	—	—	—		Steam Injection & SCR	—
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	—	—	—	42	@ 15% O2	Steam Injection	—
City of Anaheim GT Proj.	CA	Sep-89	Gas Turbine	442 MMBtu/hr	—	3.75	—	—		Steam Injection & SCR	69.60%
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.17	83	—	—		Water Injection	—
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	—	—	—	36	ppm	Water Injection	—
Cimarron Chemical Co.	CO	Aug-89	Turbines (2)	271.0 MMBtu/hr	—	—	—	65	ppmv @ 15% O2	Steam Injection	—
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	—	—	—	42	ppm	Steam Injection	—
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	—	—	—	42	ppm	Water Injection	—
Potomac Electric Power Company	MD	Mar-89	Combined Cycle	860 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	—	—	—	42	@ 15% O2	Water Injection	—

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)	Control Method	Eff. (%)
Pawtucket Power	RI	Jan-89	Turbine	58 MW	—	—	—	9	@ 15% O2	SCR	—
L&J Energy System Cogen	NY	Jan-89	GE LM 5000	40 MW	—	—	—	42	ppm	Steam Injection	—
Mojave Cogen	CA	Jan-89	Turbine	490 MMBtu/hr	0.031	—	—	—		—	—
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	—	—	—	9	@ 15% O2	Water Injection & SCR	—
Mojave Cogen	CA	Dec-88	Turbine	45 MW	—	—	—	10	ppm	Steam Injection & SCR	—
Champion International	AL	Nov-88	Gas Turbine	35 MW	—	—	—	42	@ 15% O2	Steam Injection	70.00%
Indeck-Yerks Energy Services	NY	Nov-88	GE Frame 6	40 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	—	—	—	55	ppm	Water Injection	—
Amtrak	PA	Oct-88	Turbine (2)	20 MW	—	—	—	42	@ 15% O2	H2O Injection	—
Mobile Oil	CA	Sep-88	Turbine (2)	81.40 MMBtu/hr	0.047	3.78	—	—		Water Inj. & SCR	—
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	—	—	—	42	ppm	Steam Injection	—
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	—	—	—	42	ppm	Low NOx Burners & Water Inj.	—
O'Brien Cogen	CT	Aug-88	Gas Turbine (2)	499.9 MMBtu/hr	—	—	—	39	@ 15% O2	Water Injection	—
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	—	—	—	42	ppm	Steam Injection	—
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	—	—	—	42	@ 15% O2, 1H Av	H20 Injection	59.00%
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	—	—	—	36	@ 15% O2	Water Injection	—
Merck Sharp & Pohme	PA	May-88	Turbine	310 MMBTU/hr	—	—	—	42	@ 15% O2	Steam Injection	—
Virginia Power	VA	Apr-88	GE Turbine	1,875 MMBTU/hr	—	490		42	@ 15% O2	Steam Injection	—
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.2	—	—	75	ppm	H2O Inj. & Combustion Controls	—
Combined Energy Resources	CA	Feb-88	Gas Turbine	25.94 MW	—	199.0	—	—		H2O Injection & SCR	81.00%
Texas Gas Transmission Corp.	KY	Feb-88	Gas Turbine	14300 HP	—	—	--	--		NOx 0.015 % by Volume	--
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	—	—	--	42	@ 15% O2	Steam Injection	--
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	—	85	—	—		Water Inj. & Quiet Combustion	—
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	—	--	--	42	ppmvd @ 15% O2	Water Injection	—
BAF Energy	CA	Jul-87	Turbine, Generator	887.2 MMBTU/hr	—	30.1	--	9	ppm @ 15% O2	Steam Injection & SCR	80.00%
AES Placerita, Inc.	CA	Jul-87	Turbine	530 MMBTU/hr	—	14.2	--	9	@ 15% O2	St./F Ratio 2.2:1 & SCR	--
AES Placerita, Inc.	CA	Jul-87	Gas Turbine	530 MMBTU/hr	—	12.0	--	9	@ 15% O2	St./F Ratio 2.2:1 & SCR	—
Power Development Co.	CA	Jun-87	Gas Turbine	49 MMBTU/H	--	1.5	--	9	@ 15% O2	H2O Injection & SCR	—
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	—	10.4	--	6	@ 15% O2	H2O Injection & SCR	76.00%
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	—	—	—	9.6	@ 15% O2	H2O Injection & SCR	95.00%
Trunkline LNG	LA	May-87	Gas Turbine	147,102 SCF/hr	--	59		—		--	--

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit					Control Method	Eff. (%)
					(lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)		
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	—	50.3	—	154		Combustion Control	—
Anheuser-Busch	FL	Apr-87	Gas Turbine	95.7 MMBTU/hr	0.10	—	—	—		—	—
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW	—	—	—	75	@ 15% O2	H2O Injection	—
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	—	—	—	—		—	—
U.S. Borax & Chemical Corp.	CA	Feb-87	Gas Turbine	45 MW	—	40	—	25	ppm @ 15% O2	Proper Combust. Techniques	—
Sierra LTD.	CA	Feb-87	GE Gas Turbine	11.34 MMCF/D	0.016	4.04	—	—		Steam Injection & SCR	95.86%
Midway-Sunset Project	CA	Jan-87	Gas Turbines (3)	973 MMBTU/hr	—	113.4	—	16.31	ppmv	H2O Injection	73.00%
City of Santa Clara	CA	Jan-87	Gas Turbine	—	—	—	—	42	@ 15% O2	Water Injection	—
O'Brien NRG Systems/Merchants Re	CA	Dec-86	Gas Turbine	359.5 MMBtu/hr	—	30.3	—	15	@ 15% O2	Water Injection & SCR	—
California Dept. of Corr.	CA	Dec-86	Gas Turbine	5.1 MW	—	—	—	38	@ 15% O2	1:1 H2O Injection	—
Double 'C' Limited	CA	Nov-86	Gas Turbine	25 MW	—	8.08	—	—		H2O Inj. & Selected Catalytic Red.	—
Kern Front Limited	CA	Nov-86	Gas Turbine (2)	50 MW	—	8.08	—	4.5	@ 15% O2	Water Injection & SCR	95.80%
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	—	63	—	25	ppm @ 15% O2	Steam Injection @ St/F Ratio of 1.7/	75.00%
Wichita Falls E. I., I.	TX	Jun-86	Gas Turbine	20 MW	—	—	684	—		Steam Injection	—
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	—	—	640	—		Steam Injection	—
Kern Energy Corp.	CA	Apr-86	Gas Turbine	8.8 MMCF/D	0.023	8.29	—	—		Steam Inj., Low NOx Config. & SC	87.00%
Monarch Cogen	CA	Apr-86	Combined Cycle	92.20 MMBtu/hr	—	8.02	—	22	@ 15% O2	SCR	—
Moran Power, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.02	8.29	—	—		Steam Inj., Low NOx Config. & SC	87.00%
Southeast Energy, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.023	8.29	—	—		Steam Inj., Low NOx Config. & SC	87.00%
Western Power System, Inc	CA	Mar-86	GE Gas Turbine	26.5 MW	—	—	—	9	@ 15% O2	H2O Injection & SCR	80.00%
AES Placerita, Inc.	CA	Mar-86	Turbine	519 MMBTU/hr	—	26.2	—	7	@ 15% O2	H2O Injection & SCR	—
OLS Energy	CA	Jan-86	GE Gas Turbine	256 MMBTU/hr	—	—	—	9	@ 15% O2	H2O Injection & Scrubber	80.00%
Union Cogeneration	CA	Jan-86	Gas Turbine	16 MW	—	—	—	25	@ 15% O2	H2O Injection & Scrubber	—

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

As noted previously, there are distinct regulatory and policy differences between LAER and BACT.

All the projects in California have natural gas as the primary fuel, and only 15 of the SCR applications in California have distillate fuel as backup.

The remaining projects with SCR (i.e., 23 projects) are located in the eastern United States. These projects are located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with 87 percent less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT .

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent. The most stringent emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, two facilities have reported emission limits of about 4.5 ppm. These emission limits were clearly determined to be LAER on CTs using water injection with uncontrolled NO_x levels below 42 ppm. SCR has not been installed or permitted on simple cycle CTs.

Wet injection has been the primary method of reducing NO_x emissions from CTs. This method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2] when burning natural gas. More recently, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

In Florida, a majority of the most recent PSD permits and BACT determinations for gas turbines have required either wet injection or dry low-NO_x technology for NO_x control. The emission limits included in these permits and BACT determinations are 25 ppm (corrected to 15 percent O_2, dry conditions) for natural-gas firing.

4.3.1.2 Technology Description and Feasibility

Selective Catalytic Reduction (SCR)--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 4-4.

As presented in Table 4-4, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems, such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates backpressure on the turbine, which reduces overall heat rate.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x before to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within (i.e., about 100°F) must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.
Ammonia Control	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 2 of 2)

Consideration	Description
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip (NH_3 that passes unreacted through the catalyst and into the atmosphere) can occur if 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can occur when firing natural gas. These compounds are emitted as particulates.
Ammonia Transportation and Storage	Storage and handling of anhydrous ammonia produces additional environmental risks. Appropriate controls and contingency plans in the event of a release is required.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°F to 950°F, have been available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,000°F and above, the zeolite catalyst will be irreparably damaged. Therefore, application of an SCR system using a zeolite catalyst on a simple cycle operation is technically infeasible without exhaust gas cooling. Moreover, since zeolite catalysts have not been operated continuously in combustion exhausts greater than 900°F, the cooling system would have to reduce turbine exhaust temperatures about 200°F (i.e., to around 800°F).

Wet Injection--The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

Dry Low-NO_x Combustor--In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on machines manufactured by GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level guaranteed by ABB for the project is 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

NO_xOUT Process--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75-MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

<u>Thermal DeNO$_x$</u>--Thermal DeNO$_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the

temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal DeNO$_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO$_x$OUT process, high capital, operating, and maintenance costs are expected because of construction-specified material, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal DeNO$_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of a combustion turbine is typically about 1,000°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO$_x$ control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO$_x$ control device for CTs.

Control Technologies For Duct Firing--The proposed control technology for duct firing will be the use of low-NO$_x$ natural gas burners that will limit the emissions to 0.1 lb/10^6 Btu heat input. The latest combined cycle projects with duct firing approved by FDER in November, 1991 (i.e., Lake Cogen Limited and Pasco Cogen Limited) established 0.1 lb NO$_x$/10^6 Btu as the BACT limits. This proposed limit is the lowest being permitted for similar facilities and is one-half the NSPS limit.

Summary of Technically Feasible NO$_x$ Control Methods--The available information suggests that SCR with dry low-NO$_x$ combustor technology would produce the lowest NO$_x$ emissions and is technically feasible. Dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is a technically feasible alternative for the project.

A technical evaluation of other tail gas controls (i.e., NO_xOUT, Thermal DeNO_x, and NSCR) indicates that these processes have not been applied to CT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the BACT analysis, SCR with dry low-NO_x combustion is capable of achieving a NO_x emission level of 9 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions) and dry low-NO_x combustion alone can achieve 25 ppm (corrected).

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12), Chapter 17-2.100(25), F.A.C., and Chapter 17-2.500(5)(c), F.A.C.]. The analysis must, by definition, be specific to the project (i.e., case-by-case).

The BACT analysis was performed for the following alternatives:

1. SCR and dry low-NO_x combustion at an emission rate of approximately 9 ppmvd corrected to 15 percent O_2; maximum NO_x emissions are 141 TPY, and
2. Dry low-NO_x combustion at an emission rate of 25 ppmvd corrected to 15 percent O_2; maximum annual NO_x emissions are 401 TPY assuming an annual average temperature of 59°F (CT/duct firing case).

Economic–The total capital and annualized costs for SCR are presented in Tables 4-5 and 4-6, respectively. The total annualized cost of applying SCR with dry low-NO_x combustion is $1,917,900. The incremental reduction in NO_x emissions is 260 TPY. The incremental cost effectiveness of SCR over dry low-NO_x combustion alone is therefore estimated to be $7,377/ton of NO_x removed for the project.

Environmental–The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO_x of 25 $\mu g/m^3$, annual average, and the AAQS for NO_x, 100 $\mu g/m^3$. Indeed, the impacts are less than the significant impact levels. Additional

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	607,500	Developed from manufacturer budget quotations
Ammonia Storage Tank	172,400	Developed from manufacturer budget quotations
HRSG Modification	303,000	Developed from manufacturer budget quotations
Indirect Capital Costs		
Installation	419,300	20% of SCR associated equipment and ammonia storage tank
Engineering, Erection Supervision, Startup, and O&M Training	329,000	10% SCR equipment and catalyst, ammonia storage tank, and HRSG costs
Project Support	180,900	5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs
Ammonia Emergency Prepardness Program	19,200	Engineering estimate
Liability Insurance	18,100	0.5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs
Interest During Construction	677,100	15% of all direct and indirect capital costs, including catalyst cost
Contingency	478,300	20% of all capital costs
Total Capital Costs	3,205,100	Sum of all capital costs
Annualized Capital Costs	376,500	Capital recovery of 10% over 20 years, 11.74% per year

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Recurring Capital Costs		
SCR Catalyst (Materials and Labor)	1,489,200	Developed from manufacturer budget quotations
Contingency	297,800	20% of recurring capital costs
Total Recurring Capital Costs	1,787,000	Sum of recurring capital costs
Annualized Recurring Capital Costs	718,600	Capital recovery of 10% over 3 years, 40.21% per year

Note:
HRSG = heat recovery steam generators.
% = percent.
SCR = selective catalytic reduction.

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	20,800	16 hours/week @ $25/hour
Ammonia	27,900	$300/ton; NH_3:NO_x = 1:1 volume
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ $75/hour plus expenses @ 35% labor
Inventory Cost	58,300	Capital recovery (11.74%/year) for 1/3 of catalyst cost
Catalyst Disposal Cost	68,900	Engineering estimate
Contingency	43,700	20% of indirect costs
<u>Energy Costs</u>		
Electrical	35,000	80 kWh/hr; $0.05/kWh
Heat Rate Penalty	172,600	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh
MW Loss Penalty	98,700	84 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted
Fuel Escalation Costs	94,400	Real cost increase of fuel
Contingency	60,400	20% of energy costs; excludes fuel escalation
<u>Total Direct Annual Costs</u>	688,800	Sum of all direct annual costs
<u>Indirect Annual Costs</u>		
Overhead	34,200	60% of ammonia; 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Property Taxes and Insurance	99,800	2% of total capital costs
Annualized Capital Costs	376,500	Capital recovery of 10% over 20 years, 11.74% per year
Recurring Capital Costs	718,600	Capital recovery of 10% over 3 years, 40.21% per year
<u>Total Indirect Annual Costs</u>	1,229,100	Sum of all indirect annual costs
<u>Total Annual Costs</u>	1,917,900	Total annualized cost

Note: All calculations rounded off to the nearest $100.

kW = kilowatt.
kWh = kilowatt-hour.
kWh/hr = kilowatt-hour per hour.
MM/Btu = million British thermal units.
NH_3 = ammonia.
NO_x = nitrogen oxides.
O&M = operation and maintenance.
% = percent.

controls beyond dry low-NO_x combustors (i.e., SCR and SCR with water injection) would further reduce predicted impacts by much less than 1 percent of the PSD increment and the AAQS for the project.

The use of dry low-NO_x combustor technology is truly "pollution prevention". In contrast, use of SCR on the proposed project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be 10 ppm based on reported experience; previous permit conditions have specified this level. Ammonia emissions could be as high as 63.5 TPY. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM10; up to 23.3 TPY could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will generate secondary emissions since this lost energy will necessitate additional generation. These emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-7, which shows the emissions balance for the project with and without SCR. Emissions of carbon dioxide were included in this table since this gas is under study as required in the 1990 Clean Air Act Amendments. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261).

Ammonia delivery and storage must be handled with caution because of its hazardous nature. Special precautions would be required to assure that no environmental discharge occurs.

Energy--Energy penalties will occur with all control alternatives evaluated. However, significant energy penalties occur with SCR. With SCR, the output of the CT is reduced by about 0.50 percent over that of wet injection. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 3,900,000 kilowatt hours (kWh) in potential lost generation per year. The energy required by the SCR equipment would be about 700,800 kilowatt hours per year (kWh/yr). Taken together, the lost generation and energy

Table 4-7. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

	Project With SCR			Project Without SCR	
Pollutants	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	24	2.06	26	0	26
Sulfur Dioxide	0	22.64	23	0	23
Nitrogen Oxides	141	11.32	152	401	(249)
Carbon Monoxide	0	0.68	1	0	1
Volatile Organic Compounds	0	0.10	0	0	0
Ammonia	64	0.00	64	0	64
Total	229	36.81	266	401	(135)
Carbon Dioxide[c]	--	3,535	3,535	--	3,535

Note: Btu/kWh = British thermal units per kilowatt-hour.
CT = combustion turbine.
DB = duct burner.
MW = megawatt.
% = percent.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Lost energy of 0.47 MW for 8,760 hours per year operation. Assumes Florida Power Corp. baseloaded oil-fired unit would replace lost energy. EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh.

[b] Difference = Total with SCR minus project without SCR.

[c] Reflects differential emissions due to lost energy efficiency with SCR.

requirements of SCR could supply the electrical needs of 400 residential customers. To replace this lost energy, an additional 5.3 x 10^{10} British thermal units per year (Btu/yr) or about 53 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the project is dry low-NO_x combustion technology. The proposed NO_x emissions level using this technology is 25 ppmvd (corrected to 15 percent oxygen) when firing natural gas. This control technology is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. The estimated incremental cost of SCR for natural gas firing exceeds $7,000 per ton of NO_x removed. These costs are in the range for other projects that have rejected SCR as unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered (refer to Table 4-7). The cost effectiveness is over $15,000 per ton of pollutant removed when the emissions (exclusive of CO_2) are considered,
2. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary generations (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst replacement),
3. The energy impacts of SCR will reduce potential electrical power generation by more than 5 million kWh,
4. The proposed BACT (i.e, dry low-NO_x combustion) provides the most cost effective control alternative and results in low environmental impacts (approximately 1 percent of the allowable PSD increments and less than 1 percent of the AAQS for NO_x). Dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations. In addition, CT manufacturers have been willing to guarantee this level of NO_x emissions, and
5. The proposed emission limit for duct firing (i.e., 0.1 lb/10^6 Btu) is at a level specified as BACT for similar recent projects.

4.3.2 CARBON MONOXIDE

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table 4-8 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines.

Table 4-8. Summary of BACT Determinations for CO from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)	Control Method	Eff. (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	42		78 ppmvd for oil firing	—
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	42		78 ppmvd for oil firing	—
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	—	—	—	—		25 ppmvd for oil firing	—
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	—	5.8	—	60	@ 15% O2	Base Case, No Additional Control	—
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	—	—	—	6	@ 15% O2	CO Catalyst	80.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	—	—	—	30		33 ppmvd for oil firing	—
Commonwealth Atlantic LTD Partn	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	—	—	261	30	ppmvd	Combustion control	—
Commonwealth Atlantic LTD Partn	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	—	—	261	30	ppmvd	Combustion control	—
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	—	—	—	30		33 ppmvd for oil firing	—
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	—	—	—	10		26 ppmvd for oil firing	—
March Point Cogen	WA	Oct-90	Turbine	80 MW	—	—	—	37	@ 15% O2	Combustion Control	—
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	—	—	—	15	ppm	Good Combustion	—
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	—	25	—	—		Combustor Design & Operation	—
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	0.02	—	—	—		—	—
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	—	—	—	50	ppmvd @ iso	Design & Good Combustion Technique	—
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	—	—	—	25	ppm	Combustion Control	—
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	0.112	—	—	—		—	—
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.022	10.8	—	—		Combustion Control	—
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	0.028	—	—	—		Combustion Control	—
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	—	—	—	10	@ 15% O2	—	—
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	0.024	—	—	—		Combustion Control	—
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	0.026	—	—	—		Combustion Control	—
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	0.022	—	—	—		Combustion Control	—
Pawtucket Power	RI	Jan-89	Turbine	58 MW	—	—	—	23	@ 15% O2	—	—
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	—	—	—	25	@ 15% O2	—	—
Champion International	AL	Nov-88	Gas Turbine	35 MW	—	9	—	—		—	—
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	—	—	—	10	ppm	Combustion Control	—
Amtrak	PA	Oct-88	Turbine (2)	20 MW	—	30.76	—	—		—	—
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	0.021	—	—	—		Combustion Control	—
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	—	—	—	10	@ 15% O2	Combustion Control	—
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	—	—	—	15	ppm	Good Combustion	—
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	0.022	—	—	—		Combustion Control	—
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	0.1	—		—		Water Injection	—

Table 4-8. Summary of BACT Determinations for CO from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)	Control Method	Eff. (%)
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	0.605	—	—	—		—	—
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.181	—	—	—		CO Catalyst	80.00%
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	—	26	—	—		Turbine Design	—
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	—	94	—	—		Proper Combustion	—
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	0.048	—	—	—		—	—
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	—	55.25	—	55	@ 15% O2	Combustion Control	—
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	—	—	—	50	ppmvd @ 15	—	—
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	—	6	25	—		—	—
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW				109	lb/scf fuel	Water Injection	—
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	—	—	—	10	@ 15% O2	CO Catalyst & Comb. Control	—
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	—	—	—	—		CO Catalyst (No limit indicated)	—
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	—	—	32.4	—		—	—

Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. For the CT being evaluated, CO emissions will not exceed 10 ppm, corrected to dry conditions when firing natural gas under full load conditions. This CO emission level is near the lowest established as the BACT level.

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

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

Combustion design is dependent upon the manufacturer's operating specifications. The CT proposed for the project has been designed to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels to 10 ppm as LAER and BACT.

For duct firing, the specific burner design to control NO_x emissions has commonly established the ability of the burner to meet CO limits. Recent BACT decisions for duct firing have ranged from 0.14 $lb/10^6$ Btu for Tropicana Products, Inc. to 0.2 $lb/10^6$ Btu for the Lake and Pasco Cogen Limited projects.

4.3.2.2 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not lower CO emissions substantially and will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for combustion turbines have set limits in the 30 ppmvd range. The cost of an oxidation catalyst would be significant and not cost-effective given the proposed emission limit of 10 ppmvd for the CT only, and 16 ppmvd for the CT/HRSG exhaust.

For the duct burner, the proposed BACT limit of 0.1 lb/10^6 Btu is lower than that proposed for similar projects.

4.3.3 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emissions level is exceeded for PM/PM10 requiring PSD review (including BACT) for these pollutants. The emission of particulates from the CT is a result of incomplete combustion and trace solids in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on a gas-fueled CT.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions [about 11 pounds per hour (lb/hr)]} is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

Therefore, there are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Natural gas represents BACT for this pollutant.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas represents BACT because of its inherent low contaminant content.

5.0 AIR QUALITY MONITORING DATA

5.1 PSD PRECONSTRUCTION MONITORING

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

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

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

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

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

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

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

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

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

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

1. Using continuous instrumentation,
2. Producing quality control records that indicate the instruments' operations and performances,
3. Operating the instruments to satisfy quality assurance requirements, and
4. Recovering at least 80 percent of the data possible during the monitoring effort.

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

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for PM, NO_2, and CO emissions. The maximum predicted impacts from the proposed CT/HRSG are less than the de minimis levels for PM, NO_2, and CO (see Table 3-4). Therefore, preconstruction monitoring is not required.

6.0 AIR QUALITY MODELING APPROACH

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

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

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

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

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

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

6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the plant site. Within 50 km of the site, the terrain can be described as simple (i.e., flat to gently rolling). As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

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

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

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

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

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST model are presented in Table 6-1. Concentrations caused by stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options that affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

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

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

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

It is noted that the ISCST model was used to assess impacts near the proposed facility, as well as at the Class I PSD area located about 120 km away. Although application of the ISCST model is generally limited to approximately a 50-km distance, this model has historically been used as a

Table 6-1. Major Features of the ISCST Model

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

Source: EPA, 1990.

screening tool for assessing Class I impacts at greater distances. If the ISCST results indicate very low impacts (i.e., below the Class I significance levels), EPA and FDER generally have not required further refined modeling.

6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at the Orlando International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Orlando, located less than 10 km east of the site, was selected for use in the study because it is the closest primary weather station to the study area considered to have meteorological data representative of the project site. This station has surrounding topographical features similar to the project site and the most readily available and complete database.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Ruskin using the Holzworth approach (Holzworth, 1972). The Ruskin station is located about 127 km southwest of the site. Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

6.3 EMISSION INVENTORY

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

Modeling of the proposed CT/HRSG demonstrated that the facility's PM, NO_x, and CO impacts are below their respective significant impact levels (see Section 7.0). Therefore, further modeling for this facility is not required, and an emission inventory for other sources is not necessary.

6.4 RECEPTOR LOCATIONS

In the ISCST modeling, concentrations were predicted for the screening phase using a polar receptor grid and polar discrete receptors. A description of the receptor locations for determining maximum predicted impacts is presented below.

The screening grid receptors consisted of 360 polar grid receptors located at distances of 500; 1,000; 1,500; 2,000; 2,500; 3,000; 3,500; 4,000; and 5,000 m along 36 radials, with each radial spaced at 10-degree increments. An additional 71 discrete receptors were included to depict the property boundary and the 100-m distance, if it was beyond the property boundary. Property boundary receptors are presented in Table 6-2. Site maps depicting the site boundaries are included in the map pocket.

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

The refined modeling analysis also included receptors located a distance of 70 m when beyond plant property. The 70-m distance is representative of the minimum distance at which the ISCST model will predict a concentration for the modeled building height.

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

Table 6-2. Property Boundary Receptors Used in the Modeling Analysis

Receptor Location[a]		Receptor Location[a]	
Direction (deg)	Distance (m)	Direction (deg)	Distance (m)
10	75	190	59
20	78	200	56
30	85	210	52
40	96	220	49
50	101	230	46
60	89	240	46
70	82	250	47
80	78	260	49
90	77	270	53
100	78	280	56
110	82	290	59
120	89	300	64
130	97	310	72
140	82	320	86
150	72	330	85
160	66	340	78
170	63	350	75
180	62	360	74

Note: deg = degrees.
m = meter.
CT/HRSG = combustion turbine/heat recovery steam generators.

[a] With respect to CT/HRSG stack location.

Source: KBN, 1991.

Concentrations in the refined analysis were predicted for the entire year that produced the highest concentration from the screening receptor grid. If maximum concentrations for other years were within 10 percent of that for the highest year, those concentrations were refined as well.

Because the maximum impacts of the proposed facility are below PSD significant impact levels and the closest PSD Class I area is 121 km from the site, the maximum PSD Class I increment consumption at the Chassahowitzka Wilderness Area, a PSD Class I area, was determined for the proposed facility alone. Receptors were located at 13 discrete Cartesian receptors surrounding the border of the PSD Class I area. The highest predicted concentration over 5 years of meteorological data was compared with PSD Class I significant impact levels, which were adopted as policy by EPA on September 10, 1991 (Memorandum from John Calcagnito to Thomas Maslany). The analysis was performed for both PM and NO_x.

6.5 BUILDING DOWNWASH EFFECTS

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

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than H_b + 0.5 L_b, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector. The features of the Schulman and Scire method are as follows:

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

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

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

$$M_w = 0.8886W$$

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

The single, most dominant building structure at the site will be the HRSG building. This building is 76 ft tall, 60 ft long, and 43 ft wide. For aesthetic purposes, the building has been made large enough to cover all the tanks and has been extended to be flush with the bottom section of the rectangular stack. The building dimensions are summarized in Table 6-3. The site layout map of the proposed facility is included in the map pocket.

Table 6-3. Building Dimensions Used in ISCST Modeling Analysis To Address Potential Building Wake Effects

		Actual Building Dimensions (m)			Projected Width[a]	Modeled Building Dimensions (m)	
Source	Associated Building	Length	Width	Height	(m)	Length, Width	Height
HRSG Stack	HRSG Building	18.29	13.11	23.16	22.50	19.93	23.16

Note: m = meter.

[a] Diagonal of actual building dimensions.

Source: KBN, 1991.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED UNIT ONLY

7.1.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the maximum concentrations as a result of the proposed facility only operating at worst-case operating conditions is presented in Table 7-1. The results are presented for a generic emission rate concentration of 10 grams per second (g/s). Table 7-1 indicates the maximum screening concentrations for each year and averaging time with an emission rate of 10 g/s. Based on the results in Table 7-1, refined modeling was performed. The results of the refined modeling are presented in Table 7-2. The maximum pollutant-specific concentrations for PM, NO_2, and CO were determined from the maximum generic impacts and are presented in Table 7-3.

The maximum predicted NO_2 concentration as a result of the proposed facility only is 0.61 $\mu g/m^3$. Since this concentration is below the significance level for NO_2 (1.0 $\mu g/m^3$), no further modeling analysis is necessary for this pollutant. The maximum predicted 1-hour and 8-hour CO concentrations are 47 and 12 $\mu g/m^3$, respectively. Because these concentrations are below the PSD significant impact levels of 2,000 and 500 $\mu g/m^3$, additional modeling is not necessary for CO.

The maximum predicted annual and 24-hour average PM concentrations are 0.07 and 2.44 $\mu g/m^3$, respectively. These maximum impacts are less than the PM significant impact levels. Therefore, additional modeling is not required for this pollutant.

7.1.2 CLASS I ANALYSIS

The maximum predicted facility impacts at the Chassahowitzka Wilderness Area using a generic emission rate of 10 g/s are presented in Table 7-4. The maximum annual and 24-hour generic impacts are 0.01 and 0.17 $\mu g/m^3$, respectively. The pollutant-specific results are presented in Table 7-5. The maximum PSD PM annual and 24-hour increment consumption is 0.001 and 0.02 $\mu g/m^3$, respectively. These concentrations, developed from the ISCST model, are considerably below the PSD Class I area significant impact levels of 0.27 and 1.35 $\mu g/m^3$, respectively. As a result, no further modeling of the Class I areas was performed.

Table 7-1. Maximum Predicted Impacts for the Orlando CoGen Limited, L.P. Facility Using a Generic Emission Rate of 10 g/s - Screening Analysis

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Day/ Period
Annual					
	1982	0.45	240	100	-/-
	1983	0.36	110	82	-/-
	1984	0.40	240	100	-/-
	1985	0.34	250	100	-/-
	1986	0.24	280	100	-/-
1-Hour[b]					
	1982	112.73	360	74	169/8
	1983	80.42	80	78	83/16
	1984	80.41	340	78	272/4
	1985	67.69	90	77	137/17
	1986	54.13	100	78	27/14
3-Hour[b]					
	1982	40.23	100	78	14/6
	1983	51.42	80	78	83/6
	1984	61.43	340	78	272/2
	1985	47.19	90	77	137/6
	1986	34.04	100	78	27/5
8-Hour[b]					
	1982	19.67	100	78	14/3
	1983	17.99	90	77	45/2
	1984	23.42	340	78	272/1
	1985	28.28	90	77	43/1
	1986	16.34	60	89	58/2
24-Hour[b]					
	1982	9.82	100	78	14/1
	1983	9.36	90	77	45/1
	1984	9.34	50	101	272/1
	1985	17.30	90	77	43/1
	1986	8.24	100	78	27/1

Note: g/s = grams per second.
m = meter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed stack.

[b] All short-term concentrations indicate highest predicted concentrations.

Source: KBN, 1991.

Table 7-2. Maximum Predicted Impacts for the Orlando CoGen Limited, L.P. Facility Using a Generic Emission Rate of 10 g/s--Refined Analysis

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Day/ Period
Annual					
	1982	0.49	236	70	—/—
1-Hour[b]					
	1982	112.73	360	74	169/8
8-Hour[b]					
	1985	29.67	84	78	43/1
24-Hour[b]					
	1984	17.64	92	77	43/1

Note: g/s = grams per second.
m = meter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed stack.

[b] All short-term concentrations indicate highest predicted concentrations.

Source: KBN, 1991.

Table 7-3. Maximum Predicted Pollutant Impacts of the Orlando CoGen Limited, L.P. Facility Compared to PSD Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
Particulate Matter	Annual	11.0	0.49	0.07	1
	24-Hour		17.64	2.44	5
Nitrogen Oxides	Annual	98.6	0.49	0.61	1
Carbon Monoxide	1-Hour	33.2	112.73	47	2,000
	8-Hour		29.67	12	500

Note: Short-term maximum impacts are highest predicted concentrations for 1982-86.

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

Source: KBN, 1991.

Table 7-4. Maximum Predicted PSD Class I Impacts for the Orlando CoGen Limited, L.P. Facility Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] X (m)	Receptor Location[a] Y (m)	Day/ Period
Annual					
	1982	0.006	342000	3174000	-/-
	1983	0.005	343700	3178300	-/-
	1984	0.007	340300	3165700	-/-
	1985	0.005	340300	3165700	-/-
	1986	0.008	340300	3167700	-/-
24-Hour[b]					
	1982	0.165	342000	3174000	106/1
	1983	0.106	340700	3171900	103/1
	1984	0.118	340300	3167700	354/1
	1985	0.102	341100	3183400	242/1
	1986	0.126	343000	3176200	35/1

Note: g/s = grams per second.
m = meter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed stack.

[b] All short-term concentrations indicate highest predicted concentrations.

Source: KBN, 1991.

Table 7-5. Maximum Predicted Pollutant Impacts of the Orlando CoGen Limited, L.P. Facility Compared to PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	PSD Class I Significant Impact Levels ($\mu g/m^3$)
Particulate Matter (PM10)	Annual	11.0	0.01	0.001	0.27
	24-Hour		0.17	0.02	1.35
Nitrogen Oxides	Annual	98.6	0.01	0.01	0.1

Note: Short-term maximum impacts are highest predicted concentrations for 1982-86.

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

Source: KBN, 1991.

The maximum NO_x PSD increment consumption is 0.01 $\mu g/m^3$. This is well below the PSD Class I area significant impact level of 0.1 $\mu g/m^3$.

7.2 TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility (see Table 3-3) are presented in Table 7-6. Inorganic As is the only pollutant to be addressed and is compared in the table to FDER NTL. The maximum 8-hour, 24-hour, and annual impacts for As are well below the NTL for each respective averaging time.

7.3 ADDITIONAL IMPACT ANALYSIS

7.3.1 IMPACTS UPON SOILS AND VEGETATION

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

7.3.2 IMPACTS DUE TO ADDITIONAL GROWTH

A small work force will be employed by the facility (fewer than 12 personnel). These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in Orange County.

7.3.3 IMPACTS TO VISIBILITY

The plant is located approximately 121 km from the Chassahowitzka Wilderness Area, a PSD Class I area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were calculated for particulates and nitrogen oxides (as nitrogen dioxide). The results of the screening analysis are presented in Table 7-7. The model results show that the screening criteria are not exceeded. As a result, the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area, and no further visibility modeling is required.

Table 7-6. Predicted Maximum Impacts of Toxic Pollutants for the Orlando CoGen Limited. L.P. Facility

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic[a] Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	No Threat Levels ($\mu g/m^3$)
Sulfuric acid mist	8-Hour	0.022[b]	29.67	0.008	0.10
	24-Hour		17.64	0.005	2.38
	Annual		NA	NA	NA
Formaldehyde	8-hour	0.084[b]	29.67	0.031	4.5
	24-hour		17.64	0.019	1.08
	Annual		0.49	0.0005	0.077

Note: Short-term generic impacts are highest predicted concentrations for 1982-1986.

g/s = grams per second.
lb/hr = pounds per hour.
NA = not applicable.
TPY = tons per year.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Generic impacts are based on an emission rate of 10 g/s.
[b] Based on maximum CT emissions with duct burner.

Source: KBN, 1991.

Table 7-7. Visibility Screening Analysis for the Orlando CoGen Limited, L.P. Facility (Page 1 of 2)

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                 Visual Effects Screening Analysis for
                   Source: ORLANDO COGEN LIMITED, L.P.
                   Class I Area: CHASSAHOWITZKA WILDERNES

                   ***   Level-1 Screening   ***
 Input Emissions for

    Particulates     11.00  LB /HR
    NOx (as NO2)    96.80  LB /HR
    Primary NO2       .00  LB /HR
    Soot              .00  LB /HR
    Primary SO4       .00  LB /HR

     **** Default Particle Characteristics Assumed

                 Transport Scenario Specifications:

     Background Ozone:                    .04 ppm
     Background Visual Range:           25.00 km
     Source-Observer Distance:         121.00 km
     Min. Source-Class I Distance:     121.00 km
     Max. Source-Class I Distance:     131.00 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.   121.0    84.  2.00  .000     .05   .000
  SKY      140.  84.   121.0    84.  2.00  .000     .05   .000
  TERRAIN   10.  90.   123.4    79.  2.00  .000     .05   .000
  TERRAIN  140.  90.   123.4    79.  2.00  .000     .05   .000
```

Table 7-7. Visibility Screening Analysis for the Orlando CoGen Limited, L.P. Facility (Page 2 of 2)

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.	117.1	94.	2.00	.000	.05	.000
SKY	140.	75.	117.1	94.	2.00	.000	.05	.000
TERRAIN	10.	70.	115.0	99.	2.00	.000	.05	.000
TERRAIN	140.	70.	115.0	99.	2.00	.000	.05	.000

Note: km = kilometer.
lb/hr = pounds per hour.
m/s = meters per second.
NO_x = nitrogen oxides.
NO_2 = nitrogen dioxide.
ppm = parts per million.
SO_4 = sulfate.

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APPENDIX A

EMISSION CALCULATIONS AND FACTORS

Emission rates for all regulated and nonregulated pollutants were calculated using both manufacturer's data and EPA emission factors. The design information and emissions data are presented in Tables A-1 through A-5. These tables were generated using a computerized spreadsheet (i.e., Lotus 1-2-3). Tables A-1 through A-5 have been annotated to show the columns (i.e., A ,B, C, and D) and rows (i.e., 1, 2, 3, ...) in the spreadsheet. Following these tables is a printout of all the calculations made in the spreadsheet, along with the basis for the calculation. The calculations, as well as text comments, are listed alphanumerically in ascending order. For example, in Table A-1, column B, row 12 is listed as A:B12 on the calculation page, and the data input is 10,690: As noted, these data were provided by ABB. A copy of the relevant EPA emission factors also is included in this appendix.

Table A-1. Design Information and Stack Parameters for Orlando CoGen Limited, L.P. Cogeneration Project

Data A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
General:					
Power (kW)	87,360.0	78,830.0	75,690.0	68,350.0	NA
Heat Rate (Btu/kwh)	10,690.0	10,870.0	10,960.0	11,270.0	NA
Heat Input (mmBtu/hr)	933.9	856.9	829.6	770.3	122.0
Natural Gas (lb/hr)	44,732.4	41,044.3	39,735.7	36,897.3	5,843.8
(cf/hr)	987,186.5	905,795.0	876,915.9	814,275.4	128,964.1
Fuel:					
Heat Content - (LHV)	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	1 gr/100cf	1 gr/100cf	1 gr/100cf
CT Exhaust:	CT Only:	CT Only:	CT Only:	CT Only:	CT & DB Exhaust:
Volume Flow (acfm)	1,601,395	1,529,035	1,500,057	1,429,720	675,048
Volume Flow (scfm)	603,523	569,344	555,810	522,778	524,155
Mass Flow (lb/hr)	2,631,000	2,482,000	2,423,000	2,279,000	2,285,000
Temperature (°F)	941	958	965	984	220
Moisture (% Vol.)	6.10	6.70	7.10	9.30	9.20
Oxygen (% Vol.)	14.40	14.50	14.40	14.20	14.00
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	811,556	754,813	726,343		675,048
Temperature (°F)	250	240	230		220
Diameter (ft)	15.7	15.7	15.7		15.7
Velocity (ft/sec)	69.90	65.01	62.56		58.14

Note: CT and duct burner will fire natural gas only.
Duct burner maximum firing will be 450,000 MM Btu/year; i.e., 4,500 hours at 100 MM Btu/hr.
Duct burner operation is planned when ambient temperature is greater than 59°F.

Table A-2. Maximum Criteria Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
Particulate:					
Basis	Manufacturer	Manufacturer	Manufacturer	Manufacturer	0.01 lb/MMBtu
lb/hr	11.00	9.00	9.00	9.00	1.22
TPY	48.18	39.42	39.42	39.42	2.25
Sulfur Dioxide:					
Basis	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf
lb/hr	2.82	2.59	2.51	2.33	0.37
TPY	12.35	11.34	10.97	10.19	0.68
Nitrogen Oxides:					
Basis	25 ppm[a]	25 ppm[a]	25 ppm[a]	25 ppm[a]	0.1 lb/MMBtu
lb/hr	95.7	86.4	84.6	75.5	12.20
TPY	419.2	378.4	370.6	330.5	22.50
ppm	25.0	25.0	25.0	25.0	
Carbon Monoxide:					
Basis	10 ppm[b]	10 ppm[b]	10 ppm[b]	10 ppm[b]	0.1 lb/MMBtu
lb/hr	23.3	21.0	20.6	18.4	12.20
TPY	102.06	92.12	90.23	80.47	22.50
ppm	10.0	10.0	10.0	10.0	
VOCs:					
Basis	3 ppm[b]	3 ppm[b]	3 ppm[b]	3 ppm[b]	0.03 lb/MMBtu
lb/hr	3.18	2.98	2.89	2.66	3.66
TPY	13.9	13.0	12.7	11.6	6.75
ppm	3.0	3.0	3.0	3.0	
Lead:					
Basis					
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

[a] Corrected to 15% O_2 dry conditions.

[b] Corrected to dry conditions.

Note: Annual emission for CT when firing natural gas based on 8,760 hrs/yr. Annual emissions for duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr. Duct burner operation planned when ambient temperature is greater than 59°F.

Table A-3. Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
As (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Be (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Hg (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
F (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
H_2SO_4 (lb/hr)	$2.16x10^{-2}$	$1.98x10^{-2}$	$1.92x10^{-2}$	$1.78x10^{-2}$	$2.82x10^{-3}$
(TPY)	$9.45x10^{-2}$	$8.67x10^{-2}$	$8.40x10^{-2}$	$7.80x10^{-2}$	0.01

Sources: EPA, 1988; EPA, 1980.

Table A-4. Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
Manganese (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Copper (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
POM (lb/hr)	1.04x10^{-3}	9.56x10^{-4}	9.25x10^{-4}	8.59x10^{-4}	1.36x10^{-4}
(TPY)	4.56x10^{-3}	4.19x10^{-3}	4.05x10^{-3}	3.76x10^{-3}	2.51x10^{-4}
Formaldehyde (lb/hr)	8.25x10^{-2}	7.57x10^{-2}	7.33x10^{-2}	6.80x10^{-2}	1.08x10^{-2}
(TPY)	3.61x10^{-1}	3.31x10^{-1}	3.21x10^{-1}	2.98x10^{-1}	1.99x10^{-2}

NOTE A

Volume is calculated based on ideal gas law:

$PV = mRT/M$

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

NOTE B

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

Oxygen correction:

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

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

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

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

Substituting:

$$\begin{aligned} V_{NOx\ Act} &= V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9 \end{aligned}$$

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

NOTE C

Same as D except only moisture correction is used:

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

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

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A:A1: [W22] 'Table A-1.  Design Information and Stack Parameters for Orlando CoGen Limited, L.P.
A:G1: [W6] 1
A:A2: [W22] '          Cogeneration Project
A:G2: [W6] (G1+1)
A:A3: [W22] \_
A:B3: [W16] \_
A:C3: [W16] \_
A:D3: [W16] \_
A:E3: [W16] \_
A:F3: [W16] \_
A:G3: [W6] (G2+1)
A:G4: [W6] (G3+1)
A:A5: [W22] ^Data
A:B5: [W16] "Gas Turbine
A:C5: [W16] "Gas Turbine
A:D5: [W16] "Gas Turbine
A:E5: [W16] "Gas Turbine
A:F5: [W16] "Duct Burner
A:G5: [W6] (G4+1)
A:B6: [W16] "Natural Gas
A:C6: [W16] "Natural Gas
A:D6: [W16] "Natural Gas
A:E6: [W16] "Natural Gas
A:F6: [W16] "Natural Gas
A:G6: [W6] (G5+1)
A:B7: [W16] "20oF - B
A:C7: [W16] "59oF - C
A:D7: [W16] "72oF - D
A:E7: [W16] "102oF - E
A:F7: [W16] "90oF - F
A:G7: [W6] (G6+1)
A:A8: [W22] \_
A:B8: [W16] \_
A:C8: [W16] \_
A:D8: [W16] \_
A:E8: [W16] \_
A:F8: [W16] \_
A:G8: [W6] (G7+1)
A:G9: [W6] (G8+1)
A:A10: [W22] ^General:
A:G10: [W6] (G9+1)
A:A11: [W22] 'Power (kW)
A:B11: (,1) [W16] 87360 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C11: (,1) [W16] 78830
A:D11: (,1) [W16] 75690
A:E11: (,1) [W16] 68350
A:F11: (,1) [W16] "NA
A:G11: [W6] (G10+1)
A:A12: [W22] 'Heat Rate (Btu/kwh)
A:B12: (,1) [W16] 10690 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C12: (,1) [W16] 10870
A:D12: (,1) [W16] 10960
A:E12: (,1) [W16] 11270
A:F12: (,1) [W16] "NA
A:G12: [W6] (G11+1)
A:A13: [W22] 'Heat Input (mmBtu/hr)
A:B13: (,1) [W16] (B11*B12/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . Power * Heat Rate
A:C13: (,1) [W16] (C11*C12/1000000)
A:D13: (,1) [W16] (D11*D12/1000000)
A:E13: (,1) [W16] (E11*E12/1000000)
A:F13: (,1) [W16] 122 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Proposed
A:G13: [W6] (G12+1)
A:A14: [W22] 'Fuel Oil (lb/hr)
A:B14: (,1) [W16] (B13/0.020877)  . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C14: (,1) [W16] (C13/0.020877)
A:D14: (,1) [W16] (D13/0.020877)
A:E14: (,1) [W16] (E13/0.020877)
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A:F14: (,1) [W16] (F13/0.020877)
A:G14: [W6] (G13+1)
A:A15: [W22] '         (cf/hr)
A:B15: (,1) [W16] (B13/946*10^6) . . . . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C15: (,1) [W16] (C13/946*10^6)
A:D15: (,1) [W16] (D13/946*10^6)
A:E15: (,1) [W16] (E13/946*10^6)
A:F15: (,1) [W16] (F13/946*10^6)
A:G15: [W6] (G14+1)
A:G16: [W6] (G15+1)
A:A17: [W22] ^Fuel:
A:G17: [W6] (G16+1)
A:A18: [W22] 'Heat Content - (LHV)
A:B18: (,1) [W16] "20,877 Btu/lb . . . . . . . . . . . . . . . . . . . . . . . . . . . . Fuel Specification
A:C18: (,1) [W16] "20,877 Btu/lb
A:D18: (,1) [W16] "20,877 Btu/lb
A:E18: (,1) [W16] "20,877 Btu/lb
A:F18: (,1) [W16] "20,877 Btu/lb
A:G18: [W6] (G17+1)
A:A19: [W22] 'Sulfur
A:B19: (,1) [W16] "1 gr/100cf . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Natural Gas
A:C19: (,1) [W16] "1 gr/100cf
A:D19: (,1) [W16] "1 gr/100cf
A:E19: (,1) [W16] "1 gr/100cf
A:F19: (,1) [W16] "1 gr/100cf
A:G19: [W6] (G18+1)
A:G20: [W6] (G19+1)
A:A21: [W22] ^CT Exhaust:
A:B21: (,1) [W16] "CT Only:
A:C21: (,1) [W16] "CT Only:
A:D21: (,1) [W16] "CT Only:
A:E21: (,1) [W16] "CT Only:
A:F21: (,1) [W16] "CT & DB Exhaust:
A:G21: [W6] (G20+1)
A:A22: [W22] 'Volume Flow (acfm)
A:B22: (,0) [W16] (B24*1545*(460+B25)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . See Note A
A:C22: (,0) [W16] (C24*1545*(460+C25)/(C28*2116.8*60))
A:D22: (,0) [W16] (D24*1545*(460+D25)/(D28*2116.8*60))
A:E22: (,0) [W16] (E24*1545*(460+E25)/(E28*2116.8*60))
A:F22: (,0) [W16] (F24*1545*(460+F25)/(F28*2116.8*60))
A:G22: [W6] (G21+1)
A:A23: [W22] 'Volume Flow (scfm)
A:B23: (,0) [W16] (B24*1545*(460+68)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . . See Note A
A:C23: (,0) [W16] (C24*1545*(460+68)/(C28*2116.8*60))
A:D23: (,0) [W16] (D24*1545*(460+68)/(D28*2116.8*60))
A:E23: (,0) [W16] (E24*1545*(460+68)/(E28*2116.8*60))
A:F23: (,0) [W16] (F24*1545*(460+68)/(F28*2116.8*60))
A:G23: [W6] (G22+1)
A:A24: [W22] 'Mass Flow (lb/hr)
A:B24: (,0) [W16] 2631000 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C24: (,0) [W16] 2482000
A:D24: (,0) [W16] 2423000
A:E24: (,0) [W16] 2279000
A:F24: (,0) [W16] 2285000
A:G24: [W6] (G23+1)
A:A25: [W22] 'Temperature (oF)
A:B25: (,0) [W16] 941 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C25: (,0) [W16] 958
A:D25: (,0) [W16] 965
A:E25: (,0) [W16] 984
A:F25: (,0) [W16] 220 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:G25: [W6] (G24+1)
A:A26: [W22] 'Moisture (% Vol.)
A:B26: (F2) [W16] 6.1 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C26: (F2) [W16] 6.7
A:D26: (F2) [W16] 7.1
A:E26: (F2) [W16] 9.3
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A:F26: (F2) [W16] 9.2
A:G26: [W6] (G25+1)
A:A27: [W22] 'Oxygen (% Vol.)
A:B27: (F2) [W16] 14.4 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C27: (F2) [W16] 14.5
A:D27: (F2) [W16] 14.4
A:E27: (F2) [W16] 14.2
A:F27: (F2) [W16] 14
A:G27: [W6] (G26+1)
A:A28: [W22] 'Molecular Weight
A:B28: (F2) [W16] 28 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Calculated
A:C28: (F2) [W16] 28
A:D28: (F2) [W16] 28
A:E28: (F2) [W16] 28
A:F28: (F2) [W16] 28
A:G28: [W6] (G27+1)
A:G29: [W6] (G28+1)
A:G30: [W6] (G29+1)
A:A31: [W22] ^HRSG Stack:
A:G31: [W6] (G30+1)
A:A32: [W22] 'Volume Flow (acfm)
A:B32: (,0) [W16] (B22*(B33+460)/(B25+460)) . . . . . . . . . . . . . . . . . . . . Adjustment for Temperature
A:C32: (,0) [W16] (C22*(C33+460)/(C25+460))
A:D32: (,0) [W16] (D22*(D33+460)/(D25+460))
A:F32: (,0) [W16] (F22*(F33+460)/(F25+460))
A:G32: [W6] (G31+1)
A:A33: [W22] 'Temperature (oF)
A:B33: (,0) [W16] 250 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:C33: (,0) [W16] 240
A:D33: (,0) [W16] 230
A:F33: (,0) [W16] 220
A:G33: [W6] (G32+1)
A:A34: [W22] 'Diameter (ft)
A:B34: (F0) [W16] 15.7 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:C34: (F0) [W16] 15.7
A:D34: (F0) [W16] 15.7
A:F34: (F0) [W16] 15.7
A:G34: [W6] (G33+1)
A:A35: [W22] 'Velocity (ft/sec)
A:B35: (F2) [W16] (B32/60/(B34^2*3.14159/4)) . . . . . . . . . . . . . . . . . . . . . . Volume ÷ Flow
A:C35: (F2) [W16] (C32/60/(C34^2*3.14159/4))
A:D35: (F2) [W16] (D32/60/(D34^2*3.14159/4))
A:F35: (F2) [W16] (F32/60/(F34^2*3.14159/4))
A:G35: [W6] (G34+1)
A:G36: [W6] (G35+1)
A:A37: [W22] \_
A:B37: [W16] \_
A:C37: [W16] \_
A:D37: [W16] \_
A:E37: [W16] \_
A:F37: [W16] \_
A:G37: [W6] (G36+1)
A:G38: [W6] (G37+1)
A:A39: [W22] 'Note: CT will fire natural gas only.
A:G39: [W6] (G38+1)
A:A40: [W22] '      Duct burner will use 450,000 MM Btu/year; i.e., 4,500 hours at 100 MM Btu/hr.
A:G40: [W6] (G39+1)
A:A41: [W22] '      Duct burner will only be oprated when ambient temperature is greater than 72oF.
A:G41: [W6] (G40+1)
```

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A:A47: [W22] 'Table A-2.  Maximum Criteria Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G47: [W6] 47
A:A48: [W22] '            Cogeneration Project
A:G48: [W6] (G47+1)
A:A49: [W22] \_
A:B49: [W16] \_
A:C49: [W16] \_
A:D49: [W16] \_
A:E49: [W16] \_
A:F49: [W16] \_
A:G49: [W6] (G48+1)
A:G50: [W6] (G49+1)
A:A51: [W22] ^Pollutant
A:B51: [W16] "Gas Turbine
A:C51: [W16] "Gas Turbine
A:D51: [W16] "Gas Turbine
A:E51: [W16] "Gas Turbine
A:F51: [W16] "Duct Burner
A:G51: [W6] (G50+1)
A:B52: [W16] "Natural Gas
A:C52: [W16] "Natural Gas
A:D52: [W16] "Natural Gas
A:E52: [W16] "Natural Gas
A:F52: [W16] "Natural Gas
A:G52: [W6] (G51+1)
A:A53: [W22] ^A
A:B53: [W16] "20oF - B
A:C53: [W16] "59oF - C
A:D53: [W16] "72oF - D
A:E53: [W16] "102oF - E
A:F53: [W16] "90oF - F
A:G53: [W6] (G52+1)
A:A54: [W22] \_
A:B54: [W16] \_
A:C54: [W16] \_
A:D54: [W16] \_
A:E54: [W16] \_
A:F54: [W16] \_
A:G54: [W6] (G53+1)
A:G55: [W6] (G54+1)
A:A56: [W22] 'Particulate:
A:G56: [W6] (G55+1)
A:A57: [W22] '  Basis
A:B57: (,1) [W16] "Manufacturer
A:C57: (,1) [W16] "Manufacturer
A:D57: (,1) [W16] "Manufacturer
A:E57: (,1) [W16] "Manufacturer
A:F57: (,1) [W16] "0.01 lb/MMBtu
A:G57: [W6] (G56+1)
A:A58: [W22] '  lb/hr
A:B58: (F2) [W16] 11  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C58: (F2) [W16] 9
A:D58: (F2) [W16] 9
A:E58: (F2) [W16] 9
A:F58: (F2) [W16] ($F$13*0.01)
A:G58: [W6] (G57+1)
A:A59: [W22] '  TPY
A:B59: (F2) [W16] (B58*8760/2000) . . . . . . . . . . . . . . . . .  Emissions * 8,760 hours/year ÷ 2,000 lb/ton
A:C59: (F2) [W16] (C58*8760/2000)
A:D59: (F2) [W16] (058*8760/2000)
A:E59: (F2) [W16] (E58*8760/2000)
A:F59: (F2) [W16] (F58*3688.5/2000) .  Emissions * 3,688.5 hr/yr (4,500 hrs @ 100x10^6 + 122 x 10^6) ÷ 2,000 lb/ton
A:G59: [W6] (G58+1)
A:G60: [W6] (G59+1)
A:A61: [W22] 'Sulfur Dioxide:
A:G61: [W6] (G60+1)
A:A62: [W22] '  Basis
```

```
A:B62: (,1) [W16] "1 gr/100 cf
A:C62: (,1) [W16] "1 gr/100 cf
A:D62: (,1) [W16] "1 gr/100 cf
A:E62: (,1) [W16] "1 gr/100 cf
A:F62: (,1) [W16] "1 gr/100 cf
A:G62: [W6] (G61+1)
A:A63: [W22] '  lb/hr
A:B63: (F2) [W16] (B15*1/7000*2/100)  . . . . . . . Fuel Used (CF/HR) * Sulfur Content * 2 lb SO2/lb S * 1/100 CF
A:C63: (F2) [W16] (C15*1/7000*2/100)
A:D63: (F2) [W16] (D15*1/7000*2/100)
A:E63: (F2) [W16] (E15*1/7000*2/100)
A:F63: (F2) [W16] (F15*1/7000*2/100)
A:G63: [W6] (G62+1)
A:A64: [W22] '  TPY
A:B64: (F2) [W16] (B63*8760/2000)
A:C64: (F2) [W16] (C63*8760/2000)
A:D64: (F2) [W16] (D63*8760/2000)
A:E64: (F2) [W16] (E63*8760/2000)
A:F64: (F2) [W16] (F63*3688.5/2000)
A:G64: [W6] (G63+1)
A:G65: [W6] (G64+1)
A:A66: [W22] 'Nitrogen Oxides:
A:G66: [W6] (G65+1)
A:A67: [W22] '  Basis
A:B67: (,1) [W16] "25 ppm*
A:C67: (,1) [W16] "25 ppm*
A:D67: (,1) [W16] "25 ppm*
A:E67: (,1) [W16] "25 ppm*
A:F67: (,1) [W16] "0.1 lb/MMBtu
A:G67: [W6] (G66+1)
A:A68: [W22] '  lb/hr
A:B68: (,1) [W16] (B70/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*46*60/(1545*(460+B25)*1000000))  . . . . See Note B
A:C68: (,1) [W16] (C70/5.9*(20.9*(1-C26/100)-C27)*C22*2116.8*46*60/(1545*(460+C25)*1000000))
A:D68: (,1) [W16] (D70/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*46*60/(1545*(460+D25)*1000000))
A:E68: (,1) [W16] (E70/5.9*(20.9*(1-E26/100)-E27)*E22*2116.8*46*60/(1545*(460+E25)*1000000))
A:F68: (F2) [W16] ($F$13*0.1) . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:G68: [W6] (G67+1)
A:A69: [W22] '  TPY
A:B69: (F1) [W16] (B68*8760/2000)
A:C69: (F1) [W16] (C68*8760/2000)
A:D69: (F1) [W16] (D68*8760/2000)
A:E69: (F1) [W16] (E68*8760/2000)
A:F69: (F2) [W16] (F68*3688.5/2000)
A:G69: [W6] (G68+1)
A:A70: [W22] '  ppm
A:B70: (,1) [W16] 25  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C70: (,1) [W16] 25
A:D70: (,1) [W16] 25
A:E70: (,1) [W16] 25
A:G70: [W6] (G69+1)
A:G71: [W6] (G70+1)
A:A72: [W22] 'Carbon Monoxide:
A:G72: [W6] (G71+1)
A:A73: [W22] '  Basis
A:B73: (,1) [W16] "10 ppm+
A:C73: (,1) [W16] "10 ppm+
A:D73: (,1) [W16] "10 ppm+
A:E73: (,1) [W16] "10 ppm+
A:F73: (,1) [W16] "0.2 lb/MMBtu
A:G73: [W6] (G72+1)
A:A74: [W22] '  lb/hr
A:B74: (,1) [W16] (B76/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*28*60/(1545*(460+B25)*1000000))  . . . . See Note C
A:C74: (,1) [W16] (C76/5.9*(20.9*(1-C26/100)-C27)*C22*2116.8*28*60/(1545*(460+C25)*1000000))
A:D74: (,1) [W16] (D76/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*28*60/(1545*(460+D25)*1000000))
A:E74: (,1) [W16] (E76/5.9*(20.9*(1-E26/100)-E27)*E22*2116.8*28*60/(1545*(460+E25)*1000000))
A:F74: (F2) [W16] ($F$13*0.2) . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:G74: [W6] (G73+1)
```

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A:A75: [W22] '  TPY
A:B75: (F2) [W16] (B74*8760/2000)
A:C75: (F2) [W16] (C74*8760/2000)
A:D75: (F2) [W16] (D74*8760/2000)
A:E75: (F2) [W16] (E74*8760/2000)
A:F75: (F2) [W16] (F74*3688.5/2000)
A:G75: [W6] (G74+1)
A:A76: [W22] '  ppm
A:B76: (,1) [W16] 10
A:C76: (,1) [W16] 10
A:D76: (,1) [W16] 10
A:E76: (,1) [W16] 10
A:G76: [W6] (G75+1)
A:G77: [W6] (G76+1)
A:A78: [W22] 'VOC's:
A:G78: [W6] (G77+1)
A:A79: [W22] '  Basis
A:B79: (,1) [W16] "3 ppm+
A:C79: (,1) [W16] "3 ppm+
A:D79: (,1) [W16] "3 ppm+
A:E79: (,1) [W16] "3 ppm+
A:F79: (,1) [W16] "0.03 lb/MMBtu
A:G79: [W6] (G78+1)
A:A80: [W22] '  lb/hr
A:B80: (F2) [W16] (B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . See Note C
A:C80: (F2) [W16] (C82*(1-C26/100)*C22*2116.8*12*60/(1545*(460+C25)*1000000))
A:D80: (F2) [W16] (D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000))
A:E80: (F2) [W16] (E82*(1-E26/100)*E22*2116.8*12*60/(1545*(460+E25)*1000000))
A:F80: (F2) [W16] ($F$13*0.03) . . . . . . . . . . . . . . . . . . . . . . . . . . . Emission Factor * Heat Input
A:G80: [W6] (G79+1)
A:A81: [W22] '  TPY
A:B81: (,1) [W16] (B80*8760/2000)
A:C81: (,1) [W16] (C80*8760/2000)
A:D81: (,1) [W16] (D80*8760/2000)
A:E81: (,1) [W16] (E80*8760/2000)
A:F81: (F2) [W16] (F80*3688.5/2000)
A:G81: [W6] (G80+1)
A:A82: [W22] '  ppm
A:B82: (,1) [W16] 3
A:C82: (,1) [W16] 3
A:D82: (,1) [W16] 3
A:E82: (,1) [W16] 3
A:G82: [W6] (G81+1)
A:G83: [W6] (G82+1)
A:A84: [W22] 'Lead:
A:G84: [W6] (G83+1)
A:A85: [W22] '  Basis
A:G85: [W6] (G84+1)
A:A86: [W22] '  lb/hr
A:B86: (S2) [W16] "NA
A:C86: (S2) [W16] "NA
A:D86: (S2) [W16] "NA
A:E86: (S2) [W16] "NA
A:F86: (S2) [W16] "NA
A:G86: [W6] (G85+1)
A:A87: [W22] '  TPY
A:B87: (S2) [W16] "NA
A:C87: (S2) [W16] "NA
A:D87: (S2) [W16] "NA
A:E87: (S2) [W16] "NA
A:F87: (S2) [W16] "NA
A:G87: [W6] (G86+1)
A:A88: [W22] \_
A:B88: [W16] \_
A:C88: [W16] \_
A:D88: [W16] \_
A:E88: [W16] \_
```

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A:F88: [W16] \_
A:G88: [W6] (G87+1)
A:G89: [W6] (G88+1)
A:A90: [W22] '* corrected to 15% O2 dry conditions
A:G90: [W6] (G89+1)
A:A91: [W22] '+ corrected to dry conditions
A:G91: [W6] (G90+1)
A:A92: [W22] 'Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr.  Annual emissions for
A:G92: [W6] (G91+1)
A:A93: [W22] '      duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr.
A:G93: [W6] (G92+1)
A:A94: [W22] '      Duct burner will only be oprated when ambient temperature is greater than 72oF.
A:G94: [W6] (G93+1)
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A:A96: [W22] 'Table A-3.  Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G96: [W6] 96
A:A97: [W22] '          Cogeneration Project
A:G97: [W6] (G96+1)
A:A98: [W22] \_
A:B98: [W16] \_
A:C98: [W16] \_
A:D98: [W16] \_
A:E98: [W16] \_
A:F98: [W16] \_
A:G98: [W6] (G97+1)
A:G99: [W6] (G98+1)
A:A100: [W22] ^Pollutant
A:B100: [W16] "Gas Turbine
A:C100: [W16] "Gas Turbine
A:D100: [W16] "Gas Turbine
A:E100: [W16] "Gas Turbine
A:F100: [W16] "Duct Burner
A:G100: [W6] (G99+1)
A:B101: [W16] "Natural Gas
A:C101: [W16] "Natural Gas
A:D101: [W16] "Natural Gas
A:E101: [W16] "Natural Gas
A:F101: [W16] "Natural Gas
A:G101: [W6] (G100+1)
A:A102: [W22] ^A
A:B102: [W16] "20oF - B
A:C102: [W16] "59oF - C
A:D102: [W16] "72oF - D
A:E102: [W16] "102oF - E
A:F102: [W16] "90oF - F
A:G102: [W6] (G101+1)
A:A103: [W22] \_
A:B103: [W16] \_
A:C103: [W16] \_
A:D103: [W16] \_
A:E103: [W16] \_
A:F103: [W16] \_
A:G103: [W6] (G102+1)
A:G104: [W6] (G103+1)
A:A105: [W22] '  As (lb/hr)
A:B105: [W16] "NEG.
A:C105: [W16] "NEG.
A:D105: [W16] "NEG.
A:E105: [W16] "NEG.
A:F105: [W16] "NEG.
A:G105: [W6] (G104+1)
A:A106: [W22] '     (TPY)
A:B106: [W16] "NEG.
A:C106: [W16] "NEG.
A:D106: [W16] "NEG.
A:E106: [W16] "NEG.
A:F106: [W16] "NEG.
A:G106: [W6] (G105+1)
A:G107: [W6] (G106+1)
A:A108: [W22] '  Be (lb/hr)
A:B108: [W16] "NEG.
A:C108: [W16] "NEG.
A:D108: [W16] "NEG.
A:E108: [W16] "NEG.
A:F108: [W16] "NEG.
A:G108: [W6] (G107+1)
A:A109: [W22] '     (TPY)
A:B109: [W16] "NEG.
A:C109: [W16] "NEG.
A:D109: [W16] "NEG.
A:E109: [W16] "NEG.
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A:F109: [W16] "NEG.
A:G109: [W6] (G108+1)
A:G110: [W6] (G109+1)
A:A111: [W22] '  Hg (lb/hr)
A:B111: [W16] "NEG.
A:C111: [W16] "NEG.
A:D111: [W16] "NEG.
A:E111: [W16] "NEG.
A:F111: [W16] "NEG.
A:G111: [W6] (G110+1)
A:A112: [W22] '     (TPY)
A:B112: [W16] "NEG.
A:C112: [W16] "NEG.
A:D112: [W16] "NEG.
A:E112: [W16] "NEG.
A:F112: [W16] "NEG.
A:G112: [W6] (G111+1)
A:G113: [W6] (G112+1)
A:A114: [W22] '  F (lb/hr)
A:B114: [W16] "NEG.
A:C114: [W16] "NEG.
A:D114: [W16] "NEG.
A:E114: [W16] "NEG.
A:F114: [W16] "NEG.
A:G114: [W6] (G113+1)
A:A115: [W22] '     (TPY)
A:B115: [W16] "NEG.
A:C115: [W16] "NEG.
A:D115: [W16] "NEG.
A:E115: [W16] "NEG.
A:F115: [W16] "NEG.
A:G115: [W6] (G114+1)
A:G116: [W6] (G115+1)
A:A117: [W22] '  H2SO4 (lb/hr)
A:B117: (S2) [W16] (B63*0.005*3.06/2) . . . . . . . . . . . . .  SO2 Emission * 0.005 (%H2SO4 Formed) * MW_H2SO4/MW_SO2
A:C117: (S2) [W16] (C63*0.005*3.06/2)
A:D117: (S2) [W16] (D63*0.005*3.06/2)
A:E117: (S2) [W16] (E63*0.005*3.06/2)
A:F117: (S2) [W16] (F63*0.005*3.06/2)
A:G117: [W6] (G116+1)
A:A118: [W22] '     (TPY)
A:B118: (S2) [W16] (B117*8760/2000)
A:C118: (S2) [W16] (C117*8760/2000)
A:D118: (S2) [W16] (D117*8760/2000)
A:E118: (S2) [W16] (E117*8760/2000)
A:F118: (F2) [W16] (F117*3688.5/2000)
A:G118: [W6] (G117+1)
A:G119: [W6] (G118+1)
A:A120: [W22] \_
A:B120: [W16] \_
A:C120: [W16] \_
A:D120: [W16] \_
A:E120: [W16] \_
A:F120: [W16] \_
A:G120: [W6] (G119+1)
A:G121: [W6] (G120+1)
A:A122: [W22] 'Sources: EPA, 1988; EPA, 1980
A:G122: [W6] (G121+1)
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A:A125: [W22] 'Table A-4.  Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G125: [W6] 125
A:A126: [W22] '           Cogeneration Project
A:G126: [W6] (G125+1)
A:A127: [W22] \_
A:B127: [W16] \_
A:C127: [W16] \_
A:D127: [W16] \_
A:E127: [W16] \_
A:F127: [W16] \_
A:G127: [W6] (G126+1)
A:G128: [W6] (G127+1)
A:A129: [W22] ^Pollutant
A:B129: [W16] "Gas Turbine
A:C129: [W16] "Gas Turbine
A:D129: [W16] "Gas Turbine
A:E129: [W16] "Gas Turbine
A:F129: [W16] "Duct Burner
A:G129: [W6] (G128+1)
A:B130: [W16] "Natural Gas
A:C130: [W16] "Natural Gas
A:D130: [W16] "Natural Gas
A:E130: [W16] "Natural Gas
A:F130: [W16] "Natural Gas
A:G130: [W6] (G129+1)
A:A131: [W22] ^A
A:B131: [W16] "20oF - B
A:C131: [W16] "59oF - C
A:D131: [W16] "72oF - D
A:E131: [W16] "102oF - E
A:F131: [W16] "90oF - F
A:G131: [W6] (G130+1)
A:A132: [W22] \_
A:B132: [W16] \_
A:C132: [W16] \_
A:D132: [W16] \_
A:E132: [W16] \_
A:F132: [W16] \_
A:G132: [W6] (G131+1)
A:G133: [W6] (G132+1)
A:A134: [W22] '  Manganese (lb/hr)
A:B134: [W16] "NEG.
A:C134: [W16] "NEG.
A:D134: [W16] "NEG.
A:E134: [W16] "NEG.
A:F134: [W16] "NEG.
A:G134: [W6] (G133+1)
A:A135: [W22] '     (TPY)
A:B135: [W16] "NEG.
A:C135: [W16] "NEG.
A:D135: [W16] "NEG.
A:E135: [W16] "NEG.
A:F135: [W16] "NEG.
A:G135: [W6] (G134+1)
A:G136: [W6] (G135+1)
A:A137: [W22] '  Nickel (lb/hr)
A:B137: [W16] "NEG.
A:C137: [W16] "NEG.
A:D137: [W16] "NEG.
A:E137: [W16] "NEG.
A:F137: [W16] "NEG.
A:G137: [W6] (G136+1)
A:A138: [W22] '     (TPY)
A:B138: [W16] "NEG.
A:C138: [W16] "NEG.
A:D138: [W16] "NEG.
A:E138: [W16] "NEG.
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A:F138: [W16] "NEG.
A:G138: [W6] (G137+1)
A:G139: [W6] (G138+1)
A:A140: [W22] '  Cadmium (lb/hr)
A:B140: [W16] "NEG.
A:C140: [W16] "NEG.
A:D140: [W16] "NEG.
A:E140: [W16] "NEG.
A:F140: [W16] "NEG.
A:G140: [W6] (G139+1)
A:A141: [W22] '     (TPY)
A:B141: [W16] "NEG.
A:C141: [W16] "NEG.
A:D141: [W16] "NEG.
A:E141: [W16] "NEG.
A:F141: [W16] "NEG.
A:G141: [W6] (G140+1)
A:G142: [W6] (G141+1)
A:A143: [W22] '  Chromium (lb/hr)
A:B143: [W16] "NEG.
A:C143: [W16] "NEG.
A:D143: [W16] "NEG.
A:E143: [W16] "NEG.
A:F143: [W16] "NEG.
A:G143: [W6] (G142+1)
A:A144: [W22] '    (TPY)
A:B144: [W16] "NEG.
A:C144: [W16] "NEG.
A:D144: [W16] "NEG.
A:E144: [W16] "NEG.
A:F144: [W16] "NEG.
A:G144: [W6] (G143+1)
A:G145: [W6] (G144+1)
A:A146: [W22] '  Copper (lb/hr)
A:B146: [W16] "NEG.
A:C146: [W16] "NEG.
A:D146: [W16] "NEG.
A:E146: [W16] "NEG.
A:F146: [W16] "NEG.
A:G146: [W6] (G145+1)
A:A147: [W22] '    (TPY)
A:B147: [W16] "NEG.
A:C147: [W16] "NEG.
A:D147: [W16] "NEG.
A:E147: [W16] "NEG.
A:F147: [W16] "NEG.
A:G147: [W6] (G146+1)
A:G148: [W6] (G147+1)
A:A149: [W22] '  Vanadium (lb/hr)
A:B149: [W16] "NEG.
A:C149: [W16] "NEG.
A:D149: [W16] "NEG.
A:E149: [W16] "NEG.
A:F149: [W16] "NEG.
A:G149: [W6] (G148+1)
A:A150: [W22] '     (TPY)
A:B150: [W16] "NEG.
A:C150: [W16] "NEG.
A:D150: [W16] "NEG.
A:E150: [W16] "NEG.
A:F150: [W16] "NEG.
A:G150: [W6] (G149+1)
A:G151: [W6] (G150+1)
A:A152: [W22] '  Selenium (lb/hr)
A:B152: [W16] "NEG.
A:C152: [W16] "NEG.
A:D152: [W16] "NEG.
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A:E152: [W16] "NEG.
A:F152: [W16] "NEG.
A:G152: [W6] (G151+1)
A:A153: [W22] '    (TPY)
A:B153: [W16] "NEG.
A:C153: [W16] "NEG.
A:D153: [W16] "NEG.
A:E153: [W16] "NEG.
A:F153: [W16] "NEG.
A:G153: [W6] (G152+1)
A:G154: [W6] (G153+1)
A:A155: [W22] ' POM (lb/hr)
A:B155: (S2) [W16] (B13*0.48*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-161
A:C155: (S2) [W16] (C13*0.48*2.324/1000000)
A:D155: (S2) [W16] (D13*0.48*2.324/1000000)
A:E155: (S2) [W16] (E13*0.48*2.324/1000000)
A:F155: (S2) [W16] (F13*0.48*2.324/1000000)
A:G155: [W6] (G154+1)
A:A156: [W22] '    (TPY)
A:B156: (S2) [W16] (B155*8760/2000)
A:C156: (S2) [W16] (C155*8760/2000)
A:D156: (S2) [W16] (D155*8760/2000)
A:E156: (S2) [W16] (E155*8760/2000)
A:F156: (S2) [W16] (F155*3688.5/2000)
A:G156: [W6] (G155+1)
A:G157: [W6] (G156+1)
A:A158: [W22] ' Formaldehyde (lb/hr)
A:B158: (S2) [W16] (B13*38*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-156
A:C158: (S2) [W16] (C13*38*2.324/1000000)
A:D158: (S2) [W16] (D13*38*2.324/1000000)
A:E158: (S2) [W16] (E13*38*2.324/1000000)
A:F158: (S2) [W16] (F13*38*2.324/1000000)
A:G158: [W6] (G157+1)
A:A159: [W22] '    (TPY)
A:B159: (S2) [W16] (B158*8760/2000)
A:C159: (S2) [W16] (C158*8760/2000)
A:D159: (S2) [W16] (D158*8760/2000)
A:E159: (S2) [W16] (E158*8760/2000)
A:F159: (S2) [W16] (F158*3688.5/2000)
A:G159: [W6] (G158+1)
A:A160: [W22] \_
A:B160: [W16] \_
A:C160: [W16] \_
A:D160: [W16] \_
A:E160: [W16] \_
A:F160: [W16] \_
A:G160: [W6] (G159+1)
A:G161: [W6] (G160+1)
A:G162: [W6] (G161+1)
A:G165: [W6] 165
A:G166: [W6] (G165+1)
A:G167: [W6] (G166+1)
A:G168: [W6] (G167+1)
A:G169: [W6] (G168+1)
A:G170: [W6] (G169+1)
A:G171: [W6] (G170+1)
A:G172: [W6] (G171+1)
A:G173: [W6] (G172+1)
A:G174: [W6] (G173+1)
A:G175: [W6] (G174+1)
A:G176: [W6] (G175+1)
A:G177: [W6] (G176+1)
A:G178: [W6] (G177+1)
A:G179: [W6] (G178+1)
A:G180: [W6] (G179+1)
A:G181: [W6] (G180+1)
A:G182: [W6] (G181+1)
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A:G183: [W6] (G182+1)
A:G184: [W6] (G183+1)
A:G185: [W6] (G184+1)
A:G186: [W6] (G185+1)
A:G187: [W6] (G186+1)
A:G188: [W6] (G187+1)
A:G189: [W6] (G188+1)
A:G190: [W6] (G189+1)
A:G191: [W6] (G190+1)
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