FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

February 17, 2000

Mr. Al Linero, P.E.
State of Florida
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: FPL Martin Peaking Project
Submittal of PSD Application

0850001-008-AC
PSD-FI-286

Dear Al:

Enclosed for your use please find seven (7) copies of a PSD permit application for the Martin plant. As we've discussed previously, this project involves the construction of two GE 7FA combustion turbine peaking units to be operated in simple cycle mode, primarily on natural gas fuel.

Please note that FPL is concurrently applying for a modification to the existing Martin Site Certification for this project; I expect to send copies of that application to your office within a few days. Pursuant to a conversation with Teresa Heron of your staff, I understand that the $10,000.00 fee that FPL will submit to the FDEP Siting Office for the Site Certification modification will also cover the Department's expenses in processing the PSD application; therefore no separate fee is enclosed.

I would be pleased to answer any questions you may have regarding this project. At your convenience, please feel free to contact me at (561) 691-7058 or via email at rich_piper@fpl.com.

Very truly yours,

Richard Piper

Richard Piper
Licensing Manager
Florida Power & Light Company

cc:
FDEP Southeast District Office

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

February 17, 2000

9937614

A.A. Linero, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

RECEIVED

FEB 18 2000

BUREAU OF AIR REGULATION

RE: FPL MARTIN PERKING UNITS

0850001-008-AC
PSD-FL-286

Dear Al:

Please find attached 7 copies of the original Professional Engineer Statements for the Air Permit Application and Prevention of Significant Deterioration Analysis for the FPL Martin Peaking Units. These were inadvertently left out of the copies sent to Rich Piper and subsequently submitted to the Department. Please call if there are any technical questions on the application. Your assistance is always appreciated.

Sincerely,

Ken

Kennard F. Kosky, P.E.
Principal

KFK/jkw

Enclosures

cc: Rich Piper, FPL

4. Professional Engineer Statement:

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

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

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

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Signature: [signature]　　　Date: 2/14/2000

(seal)

* Attach any exception to certification statement.

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Kennard F. Kosky — 2/14/2000

Signature — Date

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Signature — 2/14/2000
Date

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Signature: [signature]   Date: 2/14/2000

(seal)

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Kennard F. Kosky — 2/14/2000

Signature — Date

(seal)

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[illegible signature] 2/14/2000

Signature Date

(seal)

* Attach any exception to certification statement.

File Copy

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR THE SIMPLE CYCLE COMBUSTION TURBINE PROJECT FPL MARTIN POWER PLANT

Prepared For:
Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida 33408

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

February 2000
9937614Y/F1

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF TABLES

TABLE OF CONTENTS

LIST OF TABLES

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF APPENDICES

LIST OF ACROYNMS AND ABBREVIATIONS

AAQS	ambient air quality standards
acfm	actual cubic feet per minute
ARC	ambient reference concentrations
BACT	best available control technology
BPIP	Building Profile Input Program
Btu/yr	British thermal units per year
CAA	Clean Air Act
CALPOST	California Puff Postprocessor Model
CALPUFF	California Puff Model
CEC	cation exchange capacity
CEM	continuous emission monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
DEP	Department of Environmental Protection
DLN	dry-low NO_x
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FGT	Florida Gas Transmission
ft	foot
ft/sec	foot per second
g/s	grams per second
GEP	good engineering practice
Golder	Golder Associates Inc.
HAP	hazardous air pollutant
HRSG	heat-recovery steam generator
HSH	highest, second-highest
IMPROVE	Interagency Monitoring of Protected Visual Environments

LIST OF ACROYNMS AND ABBREVIATIONS

ISCST3	Industrial Source Complex Short-term
km	kilometer
kPa	kilopascal
kWh	kilowatt hours
kV	kilovolt
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
m^3	cubic meters
m/s	meters per second
mmBtu/hr	million British thermal units per hour
mmcf/yr	million cubic feet per year
MW	megawatt
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxide
NPS	National Park Service
NSPS	new source performance standards
NSR	new source review
NWA	National Wilderness Area
NWS	National Weather Service
O_3	ozone
OSHA	Occupational Safety and Health Administration
PM	particulate matter
PM_{10}	particulate matter with aerodynamic diameter of 10 microns or less
ppm	parts per million
ppmvd	parts per million volume dry
ppmvw	parts per million volume wet
PPSA	Florida's Power Plant Siting Act

LIST OF ACROYNMS AND ABBREVIATIONS

PSD	prevention of significant deterioration
psi	pound per square inch
QA/QC	quality assurance/quality control
SCR	selective catalytic reduction
SCRAM	Support Center for Regulatory Air Models
SIL	significant impact level
SIP	Florida's State Implementation Plan
SO_2	sulfur dioxide
STAR	stability array
TPY	tons per year
TSP	total suspended particulate matter
TTN	Technical Transfer Network
$\mu g/m^3$	micrograms per cubic meter
USC	United States Code
VOC	volatile organic compound

PART A

AIR PERMIT APPLICATION

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Florida Power and Light Company**	
2. Site Name: **Martin Power Plant**	
3. Facility Identification Number: **0850001** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **7 miles N. Indiantown on S.R. 710** City: **Indiantown** County: **Martin** Zip Code: **34956**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Richard G. Piper**
2. Application Contact Mailing Address: Organization/Firm: **Florida Power and Light Company** Street Address: **700 Universe Blvd.** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Application Contact Telephone Numbers: Telephone: **(561) 691 - 7058** Fax: **(561) 691 - 7070**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	February 18, 2000
2. Permit Number:	0850001-008-AC
3. PSD Number (if applicable):	PSD-FL-286
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:______________________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:______________________________________

Operation permit number to be revised:____________________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:___________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:____________________________________

Reason for revision:____

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[**X**] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **John M. Lindsay, Plant General Manager**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Florida Power and Light Company, Martin Plant** Street Address: **P.O. Box 176** City: **Indiantown** State: **FL** Zip Code: **34956**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(561) 597 - 7106** Fax: **(561) 597 - 7416**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* JM Lindsay 2/17/00 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 336 - 5600** Fax: **(352) 336 - 6603**

4. Professional Engineer Statement:

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Kennard F. Kosky — 2/14/2000

Signature — Date

(seal) KFK

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Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
--	GE Frame 7FA Combustion Turbine	AC1A	
--	GE Frame 7FA Combustion Turbine	AC1A	
--	Natural Gas Heaters	AC1A	
--	Unregulated Emissions	AC1A	

Application Processing Fee

Check one: [X] Attached - Amount: $: 7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Construction of 2 170-MW GE FRAME 7FA combustion turbines. See Attachment PSD-PMR.**
2. Projected or Actual Date of Commencement of Construction: **1 Aug 2000**
3. Projected Date of Completion of Construction: **1 Jun 2001**

Application Comment

See Attachment PSD-PMR

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **543.1** North (km): **2992.9**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27 / 3 / 13** Longitude (DD/MM/SS): **80 / 33 / 46**			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **Project consists of two 170-MW dual-fuel, General Electric Frame 7FA combustion turbines(CT) that will use dry low-nitrogen oxide combustion technology when firing natural gas and water injection when firing distillate fuel oil. Each CT will operate up to 3,390 hours per year. Current facility Title V Permit No.: 0850001-004-AV.**			

Facility Contact

1. Name and Title of Facility Contact: **Robert Lippman, Production Manager**
2. Facility Contact Mailing Address: Organization/Firm: **Florida Power and Light Company** Street Address: **P.O. Box 176** City: **Indiantown** State: **FL** Zip Code: **34956**
3. Facility Contact Telephone Numbers: Telephone: (**561**) **597 - 7108** Fax: (**561**) **597 - 7416**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [**X**] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [**X**] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [**X**] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **CT is subject to NSPS Subpart GG.**	

List of Applicable Regulations

Not Applicable	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter-Total**
VOC	**A**				**Volatile Organic Compounds**
SO_2	**A**				**Sulfur Dioxide**
NO_x	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxides**
PM_{10}	**A**				**Particulate Matter-PM_{10}**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD-PMR [ ] Not Applicable	
7. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable	
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable	
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable	
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable	
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable	
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:________________________) [ ] Not Applicable	
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable	
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable	

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA Combustion Turbine

4. Emissions Unit Identification Number:
ID:

[ ] No ID
[X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment PSD-PMR.

Emissions Unit Control Equipment

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_X combustion - Natural gas firing**
2.	Control Device or Method Code(s): **25**

Emissions Unit Details

1.	Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2.	Generator Nameplate Rating:	**172** MW	
3.	Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**
2. Control Device or Method Code(s): **28**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating: **172** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,600**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**3,390**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR-EU1-D for operational requirements	
See Attachment PSD-PMR for permitting requirements	

ATTACHMENT PMR-EU1-D

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	NSPS Subpart GG
62-204.800(7)(c) (State Only)	NSPS authority
62-204.800(7)(d)(State Only)	NSPS General Provisions
62-204.800(12) (State Only)	Acid Rain Program
62-204.800(13) (State Only)	Allowances
62-204.800(14) (State Only)	Acid Rain Program Monitoring
62-204.800(16) (State Only)	Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	Circumvention; EUs with control device
62-210.700(1)	Excess Emissions;
62-210.700(4)	Excess Emissions; poor maintenance
62-210.700(6)	Excess Emissions; notification

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	Compliance Options (if 214.430)
62-214.340	Exemptions (new units, retired units)
62-214.350(2);(3);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	All Units (Operating Rate; other than CTs;no CT)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)(a)	All Units (Applicable Test Procedures;Sampling time)
62-297.310(4)(b)	All Units (Sample Volume)
62-297.310(4)(c)	All Units (Required Flow Rate Range-PM/H2SO4/F)
62-297.310(4)(d)	All Units (Calibration)
62-297.310(4)(e)	All Units (EPA Method 5-only)
62-297.310(5)	All Units (Determination of Process Variables)

62-297.310(6)(a)	All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)
62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	FFSG excess emissions
62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.a	Annual Test
62-297.310(7)(a)5.	PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	FDEP Notification - 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(2)	Notification of Initial Start-Up
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Notification
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(e)	Provide Stack Sampling Facilities
40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention

40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c)	Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	Monitoring (COMS; span, system check)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)
40 CFR 60.13(h)	Monitoring (COMS; data requirements)
Acid Rain-Permits:	
40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	SO_2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	NO_x Requirements
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply (operate)
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID;unit/system ID
40 CFR 72.33(c)	Dispatch System ID;ID requirements
40 CFR 72.33(d)	Dispatch System ID;ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(c)	General; conditional approval
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number

Monitoring Part 75:

40 CFR 75.4	Compliance Dates;
40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	Recertification Backup/portable monitor
40 CFR 75.20(f)	Alternate Monitoring system
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.21(f)	QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; SO_2
40 CFR 75.30(b)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	General Missing Data Procedures; SO_2 (optional before 1/1/97)
40 CFR 75.30(e)	General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.40	Alternate Monitoring Systems-General
40 CFR 75.41	Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44	Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	Alternate Monitoring Systems-Daily QA
40 CFR 75.46	Alternate Monitoring Systems-Missing data
40 CFR 75.47	Alternate Monitoring Systems-Criteria for Class

40 CFR 75.48	Alternate Monitoring Systems-Petition
40 CFR 75.53	Monitoring Plan; revisions
40 CFR 75.54(a)	Recordkeeping-general
40 CFR 75.54(b)	Recordkeeping-operating parameter
40 CFR 75.54(c)	Recordkeeping-SO_2
40 CFR 75.54(d)	Recordkeeping- NO_x
40 CFR 75.54(e)	Recordkeeping-CO_2
40 CFR 75.54(f)	Recordkeeping-Opacity
40 CFR 75.55(c)	General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	General Recordkeeping (Specific Situations)
40 CFR 75.56	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A-1	Installation and Measurement Locations
Appendix A-2.	Equipment Specifications
Appendix A-3.	Performance Specifications
Appendix A-4.	Data Handling and Acquisition Systems
Appendix A-5.	Calibration Gases
Appendix A-6.	Certification Tests and Procedures
Appendix A-7.	Calculations
Appendix B	QA/QC Procedures
Appendix C-1.	Missing Data; SO_2/ NO_x for controlled sources
Appendix C-2.	Missing Data; Load-Based Procedure; NO_x & flow
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures
Appendix H	Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	Offset Plans (future)
40 CFR 77.5(b)	Deductions of Allowances (future)
40 CFR 77.6	Excess Emissions Penalties (SO_2 and NO_x;future)

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Att. PSD-PMR**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through a single stack.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,116** °F	9. Actual Volumetric Flow Rate: **2,652,300** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 1,098°F and 2,735,300 ACFM; HPM 1,130°F and 2,693,800.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **5,709**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	028	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

See Attachment PSD-PMR; Section 2.0; Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing baseload, 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** b/hour **4.25** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Methods 5 or 17; if > 400 hours

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Oil firing - all loads; ~~1,000~~ hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.
500 RGP

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing baseload, 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **31.8** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. Tons/yr based on 2,390 hrs/yr gas firing; 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **24.6** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing max @ 35°F; 100% load; TPY @ 59°F 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **31.8** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. Tons/yr based on 2,390 hrs/yr gas firing; 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 gram/100 cf - 35°F, 100% load; 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **31.8** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. Tons/yr based on 2,390 hrs/yr gas firing; 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **1.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **370.6** lb/hour **207.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd**	4. Equivalent Allowable Emissions: **370.6** lb/hour **88.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **370.6** lb/hour **207.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10.5 ppmvd**	4. Equivalent Allowable Emissions: **79.4** lb/hour **128.7** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **370.6** lb/hour **207.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **116.7** lb/hour **28.1** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.6** lb/hour **82.2** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **75.6** lb/hour **17.9** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.6** lb/hour **82.2** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.8** lb/hour **72.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.6** lb/hour **82.2** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **56.1** lb/hour **13.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM firing; 59°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.5** lb/hour **6.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **8.5** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY @ 59°F, 1,~~000~~ hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.** 500 RGP	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.5** lb/hour **6.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvd**	4. Equivalent Allowable Emissions: **3.2** lb/hour **5.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.5** lb/hour **6.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvd**	4. Equivalent Allowable Emissions: **3.2** lb/hour **0.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **4.25** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; ~~1,000~~ 500 RGP hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing baseload, 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for oil firing.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number: Serial Number:	
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested	
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable	
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD-PMR [ ] Not Applicable	
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-PMR [ ] Not Applicable	
10. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA Combustion Turbine

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code: **C**	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment PSD-PMR.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_x combustion - Natural gas firing**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

Emissions Unit Control Equipment

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**
2.	Control Device or Method Code(s): **28**

Emissions Unit Details

1.	Package Unit: Manufacturer: **General Electric** Model Number: **7FA**
2.	Generator Nameplate Rating: **172** MW
3.	Incinerator Information: Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,600**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**3,390**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR-EU1-D for operational requirements	
See Attachment PSD-PMR for permitting requirements	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Att. PSD-PMR**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,116** °F	9. Actual Volumetric Flow Rate: **2,652,300** acfm	10. Water Vapor: **8.4** %
11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: **17**	East (km): **543.1**	North (km): **2992.9**
14. Emission Point Comment (limit to 200 characters): **Stack parameters for ISO operating condition firing natural gas above; for oil 1,098°F and 2,735,300 ACFM; HPM 1,130°F and 2,693,800.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **5,709**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	028	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing baseload, 500 hrs/yr oil firingand 500 hours HPM; ISO conditions.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **4.25** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; ~~1,000~~ 500 RGP hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **17** lb/hour **18.7** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions:
[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
Reference: **GE, 2000; Golder**

7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

See Attachment PSD-PMR; Section 2.0; Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing baseload, 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **10 lb/hr**

4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year

5. Method of Compliance (limit to 60 characters):

VE Test < 20% opacity

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **31.8** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. Tons/yr based on 2,390 hrs/yr gas firing; 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **24.6** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - 35°F; 100% load; 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **31.8** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. Tons/yr based on 2,390 hrs/yr gas firing; 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 gram/100 cf - 35°F, 100% load; 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **31.8** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. Tons/yr based on 2,390 hrs/yr gas firing; 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **1.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **370.6** lb/hour **207.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd**	4. Equivalent Allowable Emissions: **370.6** lb/hour **88.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **370.6** lb/hour **207.5** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
   Reference: **GE, 2000; Golder**

7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

   See Attachment PSD-PMR; Section 2.0; Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **10.5 ppmvd**

4. Equivalent Allowable Emissions: **79.4** lb/hour **128.7** tons/year

5. Method of Compliance (limit to 60 characters):

   CEM - 30 Day Rolling Average

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **370.6** lb/hour **207.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10.5 ppmvd**	4. Equivalent Allowable Emissions: **79.4** lb/hour **128.7** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.6** lb/hour **82.2** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **75.6** lb/hour **17.9** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.6** lb/hour **82.2** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 5000 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.8** lb/hour **72.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.6** lb/hour **82.2** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **56.1** lb/hour **13.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM firing; 59°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.5** lb/hour **6.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **8.5** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY @ 59°F, ~~1,000~~ 500 RGP hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.5** lb/hour **6.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvd**	4. Equivalent Allowable Emissions: **3.2** lb/hour **5.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 8.5 lb/hour 6.4 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 2000; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-PMR; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 35°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil and HPM firing; ISO conditions	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1.5 ppmvd	4. Equivalent Allowable Emissions: 3.2 lb/hour 0.8 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A; high and low load	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY @ 59°F, 500 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **4.25** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; ~~1,000~~ 500 AGP hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **18.7** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing baseload, 500 hrs/yr oil firing and 500 hours HPM; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-PMR; Section 2.0; Appendix A.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for oil firing.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD-PMR [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-PMR [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Natural Gas Heaters

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is Natural Gas Heaters for the GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment PSD-PMR.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_X combustion - Natural gas firing**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **Gas Tech or Equivalent**	Model Number:
2. Generator Nameplate Rating:	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		23.71	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	3,390	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			
Maximum heat input per unit when natural gas firing (HHV).			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PSD-PMR for permitting requirements	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Att. PSD-PMR**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **30** feet	7. Exit Diameter: **1** foot
8. Exit Temperature: **700** °F	9. Actual Volumetric Flow Rate: **11,736** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: **17** East (km): **543.1** North (km): **2992.9**		
14. Emission Point Comment (limit to 200 characters): **Each Heater will have one stack.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas < 100 MMBtu/hr**		
2. Source Classification Code (SCC): **10100602**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.023**	5. Maximum Annual Rate: **157.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1020**
10. Segment Comment (limit to 200 characters): **Maximum hourly based on 1020 Btu/cf (HHV) for each heater; maximum annual based on 3,390 hrs/yr operation for 2 heaters.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_X	026		EL
CO			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.36** lb/hour **8** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GasTech, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on one heater. Tons/yr based on 3,390 hrs/yr for 2 heaters.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **2.36** b/hour **8** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Attachment PSD-PMR; Section 2.0.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.79** lb/hour **6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GasTech, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-PMR; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on one heater. Tons/yr based on 3,390 and 2 heaters.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.075 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Attachment PSD-PMR; Section 2.0.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for gas firing. Rule 62-296.320 allows 20% opacity**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______ of______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______of ______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-PMR [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD-PMR [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-PMR [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:________

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

[ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Unreg. Emissions Activities – 1 Tank 2.1 M gallons

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit information section addresses on 2.1 million gallon tank as unregulated emission unit. NSPS Subpart Kb recordkeeping requirements are applicable; there is no emission limiting or work practice standards. See Attachment PSD-SPC.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Oil/Diesel**		
2. Source Classification Code (SCC): **A2505030090**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **14,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Annual rate combined for both tanks based on inputs to CTs; 18,300 Btu/lb (LHV); and 7.1 lb/gal at 59°F.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			NS

PART B

ATTACHMENT PSD-PMR

PSD ANALYSIS

1.0 INTRODUCTION

Florida Power & Light Company proposes to license, install, and operate combustion turbines with a nominal capacity of 340 megawatts (MW) at the existing Martin Power Plant located in an unincorporated area of Martin County, Florida (Figure 1-1). The combustion turbines will be operated as a peaking facility at capacity factors up to 39 percent. The Martin Plant site is located in western Martin County on approximately 11,300 acres. The project consists of two 170-MW dual-fuel, General Electric Frame 7FA combustion turbines (CTs) that will use dry low-nitrogen oxide (NO_x) [dry-low NO_x (DLN)] combustion technology when operating on natural gas and water injection (for NO_x control) when operating on distillate fuel oil. The primary fuel of the CTs will be natural gas with distillate fuel oil used as backup fuel. The fuel oil in this case will contain a maximum sulfur content of 0.05 percent.

The project requires an air construction permit and prevention of significant deterioration (PSD) review. To assist in performing the necessary licensing activities, FPL contracted Golder Associates Inc. (Golder) to perform the necessary air quality assessments for determining the project's compliance with state and federal new source review (NSR) regulation. The critical aspects of these assessments include the air quality impact analyses performed using an air dispersion model and the best available control technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed project is located at a major emitting facility and will be an air pollution source that will result in increases in potential air emissions. The U.S. Environmental Protection Agency (EPA) has implemented regulations for facilities requiring a PSD review. The PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented through delegation to the Florida Department of Environmental Protection (DEP) when projects are also reviewed under Florida's Power Plant Siting Act (PPSA). The proposed project will be reviewed under FDEP's approved regulations. The Conditions of Certification for Units 3 and 4 will be modified to include the new peaking units. Units 3 and 4 are combined-cycle units with a nominal capacity of 1,000 MW.

Florida's PSD regulations are codified in Rules 62-212.400, Florida Administrative Code (F.A.C.). Florida's regulations incorporate the EPA PSD regulations.

Based on the emissions from the proposed project, a PSD review is required for each of the following regulated pollutants:

- Particulate matter (PM) as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2), and
- Carbon monoxide (CO).

Martin County has been designated as an attainment or unclassifiable area for all criteria pollutants [i.e., attainment: ozone (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is classified as a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the PSD review will follow the regulations pertaining to such designations.

The air permit application is divided into seven major sections.

- Section 2.0 presents a description of the new units, including air emissions and stack parameters.
- Section 3.0 summarizes and reviews the PSD requirements applicable to the proposed project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed project with ambient air quality standards (AAQS), PSD increments, and good engineering practice (GEP) stack height regulations.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

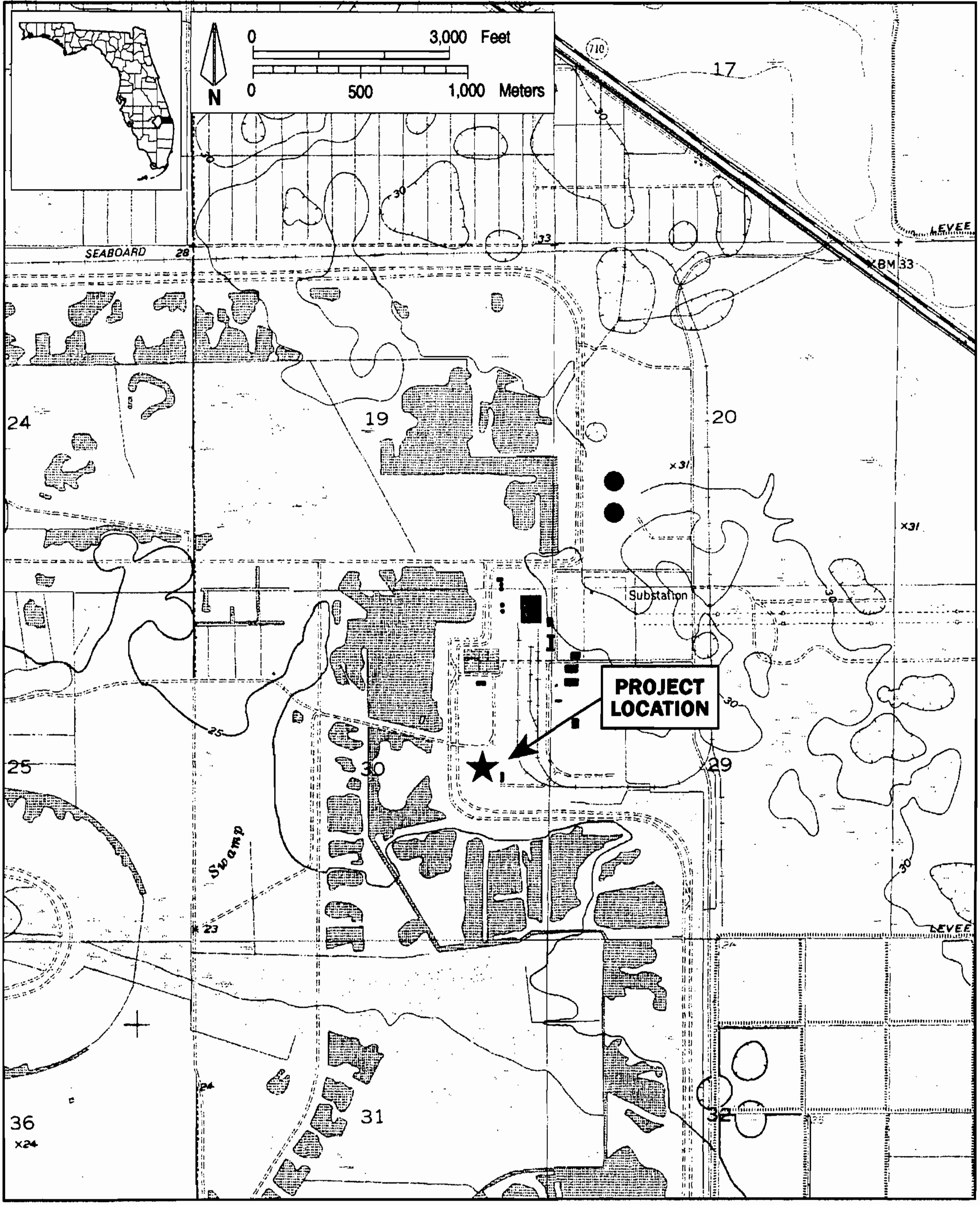


Figure 1-1
Project Location
FPL Martin

Sources: USGS, 1983; Golder, 2000.

Golder Associates

2.0 PROJECT DESCRIPTION

2.1 EXISTING SITE DESCRIPTION

The project site, shown in Figure 2-1, consists of a portion of the 11,300 acre site that includes four fossil fuel-fired units (i.e., Units 1-4). Units 1 and 2 are fossil fuel-fired steam electric generators with a nominal capacity of 1,600 MW. These units were constructed in the 1970's and fired natural gas and low sulfur (0.7 percent) residual oil. Units 3 and 4 are combined cycle units with a nominal capacity of ~~1,600~~ 1000 RGP MW. Each combined cycle units consists of two General Electric Frame 7F combustion turbines, associated heat recovery steam generators (HRSGs) and a single steam turbine. The site includes a 6,800 acre cooling reservoir used for condenser cooling and service water. The plant elevation will be approximately 50 ft above sea level. The terrain surrounding the site is flat.

Natural gas is supplied to the site by an existing lateral connected to the Florida Gas Transmission (FGT) Company's natural gas pipeline located east of the site. The site has access to electrical transmission facilities from 500 and 230-kilovolt (kV) transmission lines and electrical substations. Water for the evaporative cooler, and NO_x control when firing oil, is available from existing onsite sources. Potable water and additional fire protection supply water will be provided from existing sources.

2.2 COMBUSTION TURBINES

The proposed project will consist of two General Electric Frame 7FA CTs and associated facilities. The annual maximum capacity factor of the plant will be 39 percent, which is equivalent to operating 3,390 hours per year at full load. Natural gas will be used as the primary fuel, and fuel oil will be used as a backup fuel. Fuel oil usage will be limited to the equivalent of 500 hours per year at full load. Peak capability or power augmentation operation, when firing natural gas, would not exceed 500 hours per year. This operation is referred to as higher power modes (HPM) and are utilized to supply power above 100 percent base load when firing gas.

Plant performance with General Electric 7FA CTs was developed for natural gas and oil; at 50-, 75-, and 100-percent load; and at 35 degrees Fahrenheit (°F), 59°F, and 95°F compressor inlet temperatures. Combustion turbine performance is based on a performance envelope developed from General Electric data and has been adjusted to reflect degradation when the units operate over time and performance improvements beyond that provided by the manufacturer's guarantee. In particular, the combustion turbine emission estimates account for 5 percent higher power output and 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine.

The CTs will be capable of operating from 50 to 100 percent of baseload. The efficiency of the CTs decreases at part load. As a result, FPL will have an economic incentive to dispatch the plant to keep the units operating as near baseload as possible.

Natural gas will be transported to the units by connecting to the existing gas lateral and fuel oil will be trucked to the site. The distillate fuel oil will have a maximum sulfur content of 0.05 percent and will be stored onsite in existing aboveground storage tanks.

Air emissions control will consist of using state-of-the-art DLN burners in the CTs when firing natural gas. The General Electric Frame 7FA will be equipped with the General Electric DLN-2.6 combustion system that regulates the distribution of fuel delivery to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion system fuel nozzle is regulated to maintain unit load and minimize turbine emissions. The DLN-2.6 combustion system consists of six fuel nozzles per combustion can, with each operating as a fully premixed combustor. Of the six nozzles, five are located radially and one is in the center. The fuel system is fully automated and sequences the DLN-2.6 combustion system through a number of staging modes prior to reaching full load. The General Electric Frame 7FA has 14 combustors per turbine. Water injection will be used for NO_x control when firing distillate fuel oil. The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, volatile organic compound (VOC), and other pollutants (e.g., trace metals). These engineering and environmental designs maximize control of air emissions while minimizing economic, environmental, and energy impacts (see Section 4.0 for the BACT evaluation).

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust information representative of the proposed CT operating at baseload conditions (100-percent load), 75-percent load and 50-percent load conditions are presented in Tables 2-1 through 2-7. The information is presented in these tables for one unit operating in simple cycle operation, based on natural gas combustion and fuel oil combustion. The data are presented for compressor inlet temperatures of 35°F, 59°F, and 95°F. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience.

The performance calculations for the operating conditions are given in Appendix A.

The pollutant gaseous emission concentrations and PM_{10} emission rates for the proposed CTs are as follows:

Pollutant	Natural Gas	Distillate Oil
NO_x, ppmvd @ 15 percent O_2	10.5 (base); 15 (HPM)	42
CO, ppmvd	12 (base); 15 (HPM)	20
VOC as CH_4, ppmvd (gas), ppmvw (oil)	1.5	3.5
SO_x as SO_2	Calculated Based on Fuel (1.0 grains S/100 SCF)	Calculated Based on Fuel (0.05 percent sulfur)
PM_{10} lb/hr (dry filterable)	10	17

Note: lb/hr = pound per hour
ppmvd = parts per million volume dry
ppmvw = parts per million volume wet

The maximum short-term emission rates (lb/hr) generally occur at baseload, 35°F operation, where the CT has the greatest output and greatest fuel consumption.

Based on a compressor inlet temperature of 59°F, the emission rates used to calculate maximum potential annual emissions for the proposed facility for regulated air pollutants are presented in Table 2-8 for one and two CTs. To produce the maximum potential annual emissions, the CTs are being permitted to operate at baseload for 3,390 hours (39 percent capacity factor) firing natural gas for 3,390 hours with a maximum fuel oil operation of

500 hours at full load and 500 hours HPM operation. The potential emissions are based on the 59°F turbine inlet air condition since it represents a nominal average between the higher emission levels at the 35°F turbine inlet conditions (winter) and the relatively infrequent 95°F turbine inlet condition (summer).

Process flow diagrams of the turbine operating at compressor inlet temperature of 95°F, 59°F, and 35°F are presented in Figures 2-2 through 2-4, respectively for the "F" Class CT.

Based on a review of the emission rates for natural gas and fuel oil combustion, the highest emission rates for the regulated pollutants generally occur when firing fuel oil. Combustion of natural gas and fuel oil result in slightly different exhaust flow gas rates and stack exit temperatures; however, the differences are minor. As a result of the higher emissions when firing oil, the air modeling analyses were based on determining maximum ground-level impacts with fuel oil.

As discussed in Section 6.0, the air modeling analyses that addressed compliance with ambient standards were based on modeling the CTs for the operating load and ambient temperature which produced the maximum impacts from the load impact analysis that was performed. Although the highest emission rates occur with low compressor inlet temperatures (i.e., 35°F) and baseload conditions, the lowest exhaust gas flow rates occur with a compressor inlet temperature of 95°F and 50 percent operating load. Since this low exhaust flow condition can result in potentially higher impacts due to lower plume rise (i.e., due to lower exit velocity and temperature), the analysis included modeling the CTs for the following four scenarios which are designed to determine the maximum impacts for the project:

- Base operating load for the turbine at an inlet temperature of 35°F;
- Base operating load for the turbine at an inlet temperature of 95°F;
- A 50-percent operating load for the turbine at an inlet temperature of 35°F; and
- A 50-percent operating load for the turbine at an inlet temperature of 95°F.

The natural gas must be heated to about 300°F for the dry low-NO_x combustors to operate effectively. This will be accomplished, during simple-cycle operation, by installing direct fired natural gas heaters (two). Table 2-9 presents the performance, stack parameters, and emissions data for direct fired heaters. Only natural gas would be used in the direct fired heaters. A 50,000 barrel distillate oil tonic may also be installed. This tank will meet the requirements of 40 CFR 60 Subpart Kb.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

A plot plan of the proposed facility is presented in Figure 2-5. A profile of the units is presented in Figure 2-6. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6) F.A.C.

Table 2-1. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- Baseload for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature 35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,095	1,116	1,143
Velocity (ft/sec)		119.7	116.3	109.5
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	5.1	4.9	4.4
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	79.4	76.0	68.8
	Basis	10.5 ppmvd at 15% O_2	10.5 ppmvd at 15% O_2	10.5 ppmvd at 15% O_2
CO	lb/hr	44.8	42.6	38.8
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC[c] (as methane)	lb/hr	3.2	3.0	2.77
	Basis	1.5 ppmvd	1.5 ppmvd	1.5 ppmvd
Sulfuric Acid Mist	lb/hr	0.39	0.38	0.34
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-2. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- 75 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature 35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,122	1,139	1,170
Velocity (ft/sec)		97.9	96.2	92.1
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	4.1	4.0	3.6
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	63.3	61.0	55.9
	Basis	10.5 ppmvd at 15% O_2	10.5 ppmvd at 15% O_2	10.5 ppmvd at 15% O_2
CO	lb/hr	36.1	34.8	32.1
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC[c] (as methane)	lb/hr	2.6	2.5	2.3
	Basis	1.5 ppmvd	1.5 ppmvd	1.5 ppmvd
Sulfuric Acid Mist	lb/hr	0.32	0.30	0.28
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-3. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- 50 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature 35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,168	1,184	1,200
Velocity (ft/sec)		83.0	82.0	78.9
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	3.3	3.2	2.9
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	50.1	48.5	44.7
	Basis	10.5 ppmvd at 15% O_2	10.5 ppmvd at 15% O_2	10.5 ppmvd at 15% O_2
CO	lb/hr	29.8	28.9	27.1
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC[c] (as methane)	lb/hr	2.1	2.1	1.9
	Basis	1.5 ppmvd	1.5 ppmvd	1.5 ppmvd
Sulfuric Acid Mist	lb/hr	0.50	0.48	0.44
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-4. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil-- Baseload for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature 35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,074	1,098	1,131
Velocity (ft/sec)		123.5	119.9	111.4
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	103.1	98.6	89.1
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17.0	17.0	17.0
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	370.6	354.3	316.1
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	75.6	71.8	64.6
	Basis	20 ppmvd	20 ppmvd	20 ppmvd
VOC[c] (as methane)	lb/hr	8.5	8.1	7.4
	Basis	3.5 ppmvw	3.5 ppmvw	3.5 ppmvw
Sulfuric Acid Mist	lb/hr	7.9	7.6	6.8
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-5. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil-- 75 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature 35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,121	1,137	1,166
Velocity (ft/sec)		99.5	97.8	93.9
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	82.0	78.8	72.2
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17	17	17
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	291.5	280.4	256.6
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	71.2	68.9	64.4
	Basis	24 ppmvd	24 ppmvd	24 ppmvd
VOC[c] (as methane)	lb/hr	6.6	6.4	6.1
	Basis	3.5 ppmvw	3.5 ppmvw	3.5 ppmvw
Sulfuric Acid Mist	lb/hr	6.3	6.0	5.5
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-6. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil-- 50 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature		
		35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,168	1,182	1,200
Velocity (ft/sec)		84.1	83.2	80.5
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	64.7	62.6	57.7
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17	17	17
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	228.2	220.8	203.3
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	86.1	84.0	79.7
	Basis	35 ppmvd	35 ppmvd	35 ppmvd
VOC[c] (as methane)	lb/hr	5.4	5.3	5.1
	Basis	3.5 ppmvw	3.5 ppmvw	3.5 ppmvw
Sulfuric Acid Mist	lb/hr	5.0	4.8	4.4
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-7. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- Higher Power Modes Operation

Parameter		Operating and Emission Data[a] for Compressor Inlet Temperature		
		35°F	59°F	95°F
Stack Data (ft)				
Height (minimum)		60	60	60
Diameter (maximum)		22	22	22
Operating Data				
Temperature (°F)		1,109	1,130	1,158
Velocity (ft/sec)		121.1	118.5	114.4
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	5.3	5.1	4.8
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	116.7	112.4	106.0
	Basis	15 ppmvd at 15% O_2	15 ppmvd at 15% O_2	15 ppmvd at 15% O_2
CO	lb/hr	56.1	53.3	49.6
	Basis	15 ppmvd	15 ppmvd	15 ppmvd
VOC[c] (as methane)	lb/hr	3.2	3.1	2.8
	Basis	1.5 ppmvd	1.5 ppmvd	1.5 ppmvd
Sulfuric Acid Mist	lb/hr	0.41	0.39	0.37
	Basis	5% SO_2	5% SO_2	5% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have minor to negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, MWC organics, MWC metals, and MWC acid gases (see Appendix A).

[c] VOC emissions exclusive of background VOC concentrations.

Table 2-8. Maximum Potential Emissions (tons/year) for the FPL Martin Peaking Units

Pollutant	CT Units	Hours	Load at 59 °F Turbine Inlet 100%	75%	50%	Units	Hours	Load at 59 °F Turbine Inlet 100%	75%	50%
	Natural Gas Firing[a]									
PM	1	3,390	17.0	17.0	17.0	2	2390	23.9	23.9	23.9
SO_2	1	3,390	8.3	6.7	5.4	2	2390	11.7	9.5	7.6
NO_x	1	3,390	128.7	103.4	82.2	2	2390	181.5	145.8	116.0
CO	1	3,390	72.2	59.0	49.0	2	2390	101.8	83.1	69.1
VOC	1	3,390	5.2	4.2	3.5	2	2390	7.3	5.9	4.9
	Distillate Oil Firing[b]									
PM	1	500	4.3	4.3	4.3	2	500	8.5	8.5	8.5
SO_2	1	500	24.6	19.7	15.7	2	500	49.3	39.4	31.3
NO_x	1	500	88.6	70.1	55.2	2	500	177.2	140.2	110.4
CO	1	500	17.9	17.2	21.0	2	500	35.9	34.5	42.0
VOC	1	500	2.0	1.6	1.3	2	500	4.0	3.2	2.7
	Higher Power Modes[c]									
PM	1	500	2.5	NA	NA	2	500	5.0	NA	NA
SO_2	1	500	1.3	NA	NA	2	500	2.6	NA	NA
NO_x	1	500	28.1	NA	NA	2	500	56.2	NA	NA
CO	1	500	13.3	NA	NA	2	500	26.7	NA	NA
VOC	1	500	0.8	NA	NA	2	500	1.5	NA	NA
	Total Potential Emissions[d]									
PM	1	3,390	18.7	18.7	18.7	2	3,390	37.4	37.4	37.4
SO_2	1	3,390	31.8	25.4	20.3	2	3,390	63.6	50.9	40.5
NO_x	1	3,390	207.5	158.2	125.3	2	3,390	414.9	316.4	250.6
CO	1	3,390	82.2	67.5	62.8	2	3,390	164.3	135.0	125.6
VOC	1	3,390	6.4	5.2	4.3	2	3,390	12.8	10.4	8.6

Notes: [a] 3,390 hours per year operation as shown for one unit in Tables B-2, B-6 and B-10.
[b] 500 hours per year of oil firing as shown for one unit in Tables B-14, B-18 and B-22.
[c] 500 hours of higher power modes firing gas firing as shown for one unit in Table B-26.
[d] for 75% and 50% load the emssions are based on 2,890 hours gas firing and 500 hours of oil firing.

Table 2-9. Performance, Stack Parameters and Emissions for Natural Gas Heaters, Martin Peaking Units

	Natural Gas Heater
Performance[a]	
Fuel Usage (scf/hr-gas)	23,218
Heat Input (mmBtu/hr-HHV)	23.71
Hours per Year	3,390
Maximum Fuel Usage (mmscf/yr)	78.71
Number of Units	2
Stack Parameters	
Diameter (ft)	1.5
Height (ft)	30
Temperature (°F)	713
Velocity (ft/sec)	55
Flow (acfm)	11,736
Emissions	
SO_2 -Basis (grains S/100 scf-gas; %S diesel)[b]	1
(lb/hr)	0.066
(tpy) - one unit	0.112
(tpy) - maximum[a]	0.225
NO_x - (lb/mmBtu)[c]	0.100
(lb/hr)	2.360
(tpy)	4.000
(tpy) - maximum[a]	8.000
CO - (lb/mmBtu)[c]	0.075
(lb/hr)	1.790
(tpy)	3.034
(tpy) - maximum[a]	6.068
VOC - (lb/mmBtu)[c]	0.004
(lb/hr)	0.102
(tpy)	0.173
(tpy) - maximum[a]	0.346
PM/PM10 - (lb/10^6 ft^3)[d]	6.200
(lb/hr)	0.144
(tpy)	0.244
(tpy) - maximum[a]	0.488

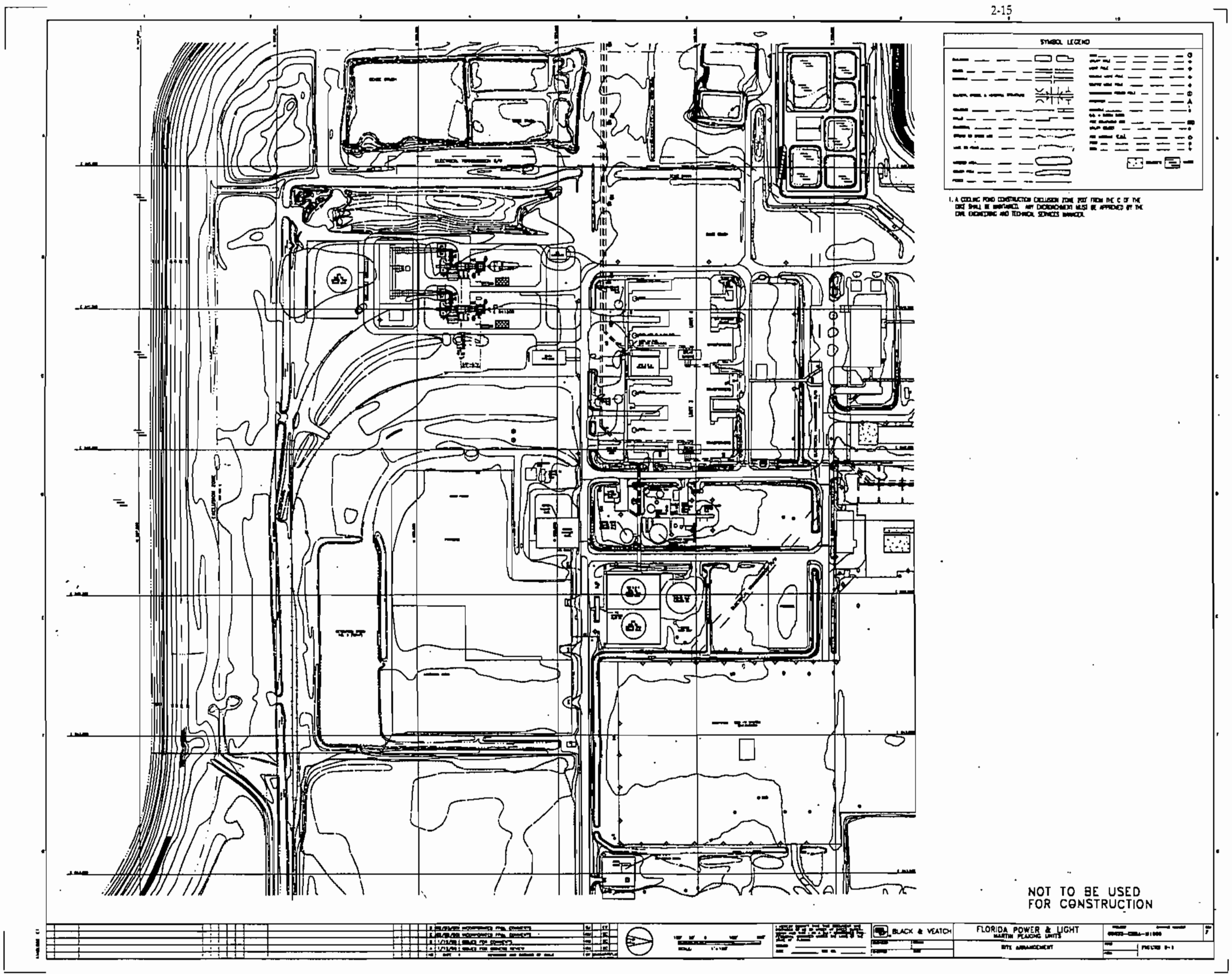
Notes:

a - GasTech, 2000.

b - Typical maximum for pipeline natural gas.

c - vendor information (GasTech)

d - AP-42 Table 1.4-2 Filterable PM; higher factor used for small heater; Table 3.3-1 PM-10


SYMBOL LEGEND
ELECTRICAL TRANSMISSION S/S
UNIT 1
UNIT 2
NOT TO BE USED
FOR CONSTRUCTION
BLACK & VEATCH
FLORIDA POWER & LIGHT
MARTIN PEAKING UNITS
SITE ARRANGEMENT

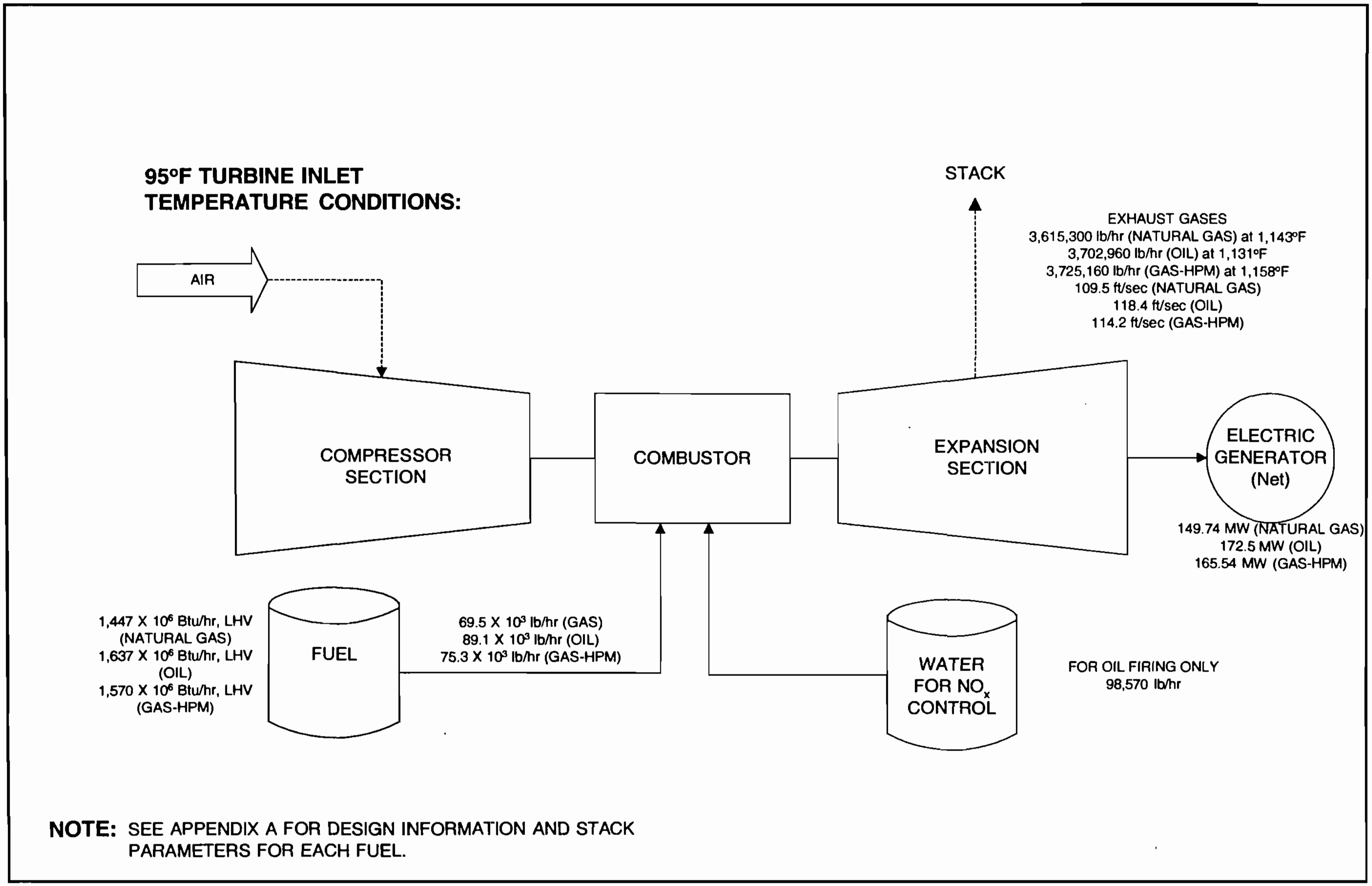
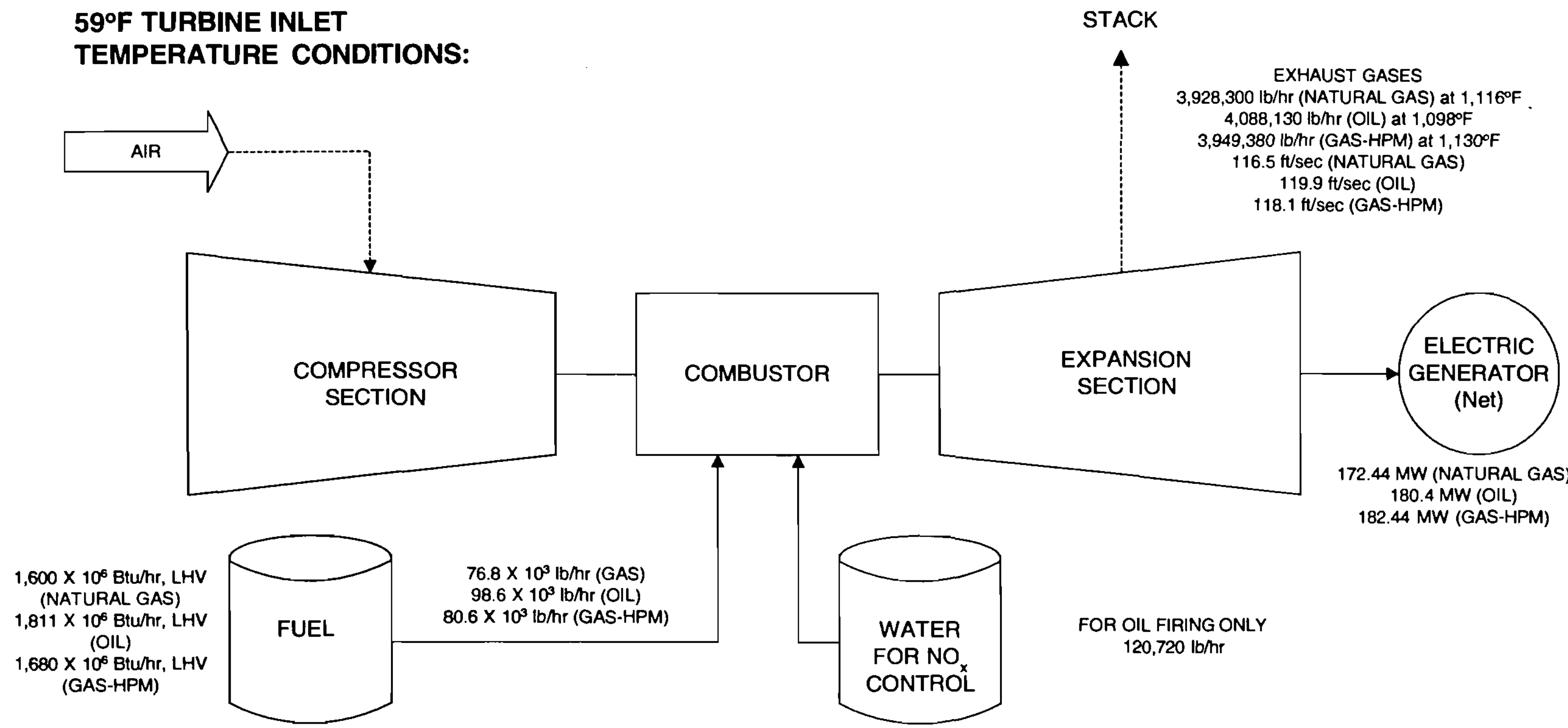


Figure 2-2
Simplified Flow Diagram of GE FRAME 7FA
Combustion Turbine
Baseload, Summer Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 9937614Y/F1/WP/FIGURES.VSD
Date: 2/10/00

Golder Associates



NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

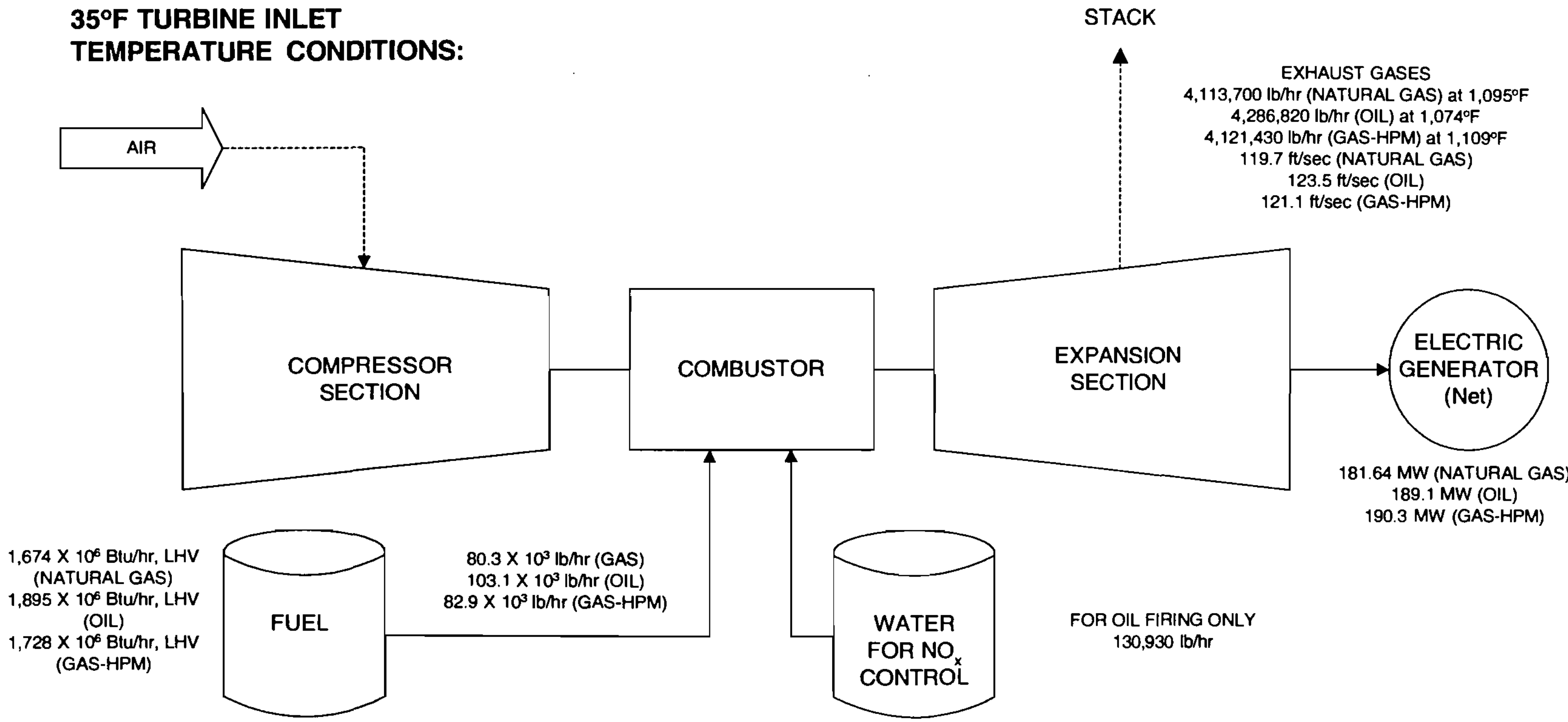
Figure 2-3
Simplified Flow Diagram of GE FRAME 7FA Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid ⟶
Gas - - - ->
Steam ·····>

Filename: 9937614Y/F1/WP/FIGURES.VSD
Date: 2/10/00

Golder Associates

35°F TURBINE INLET TEMPERATURE CONDITIONS:



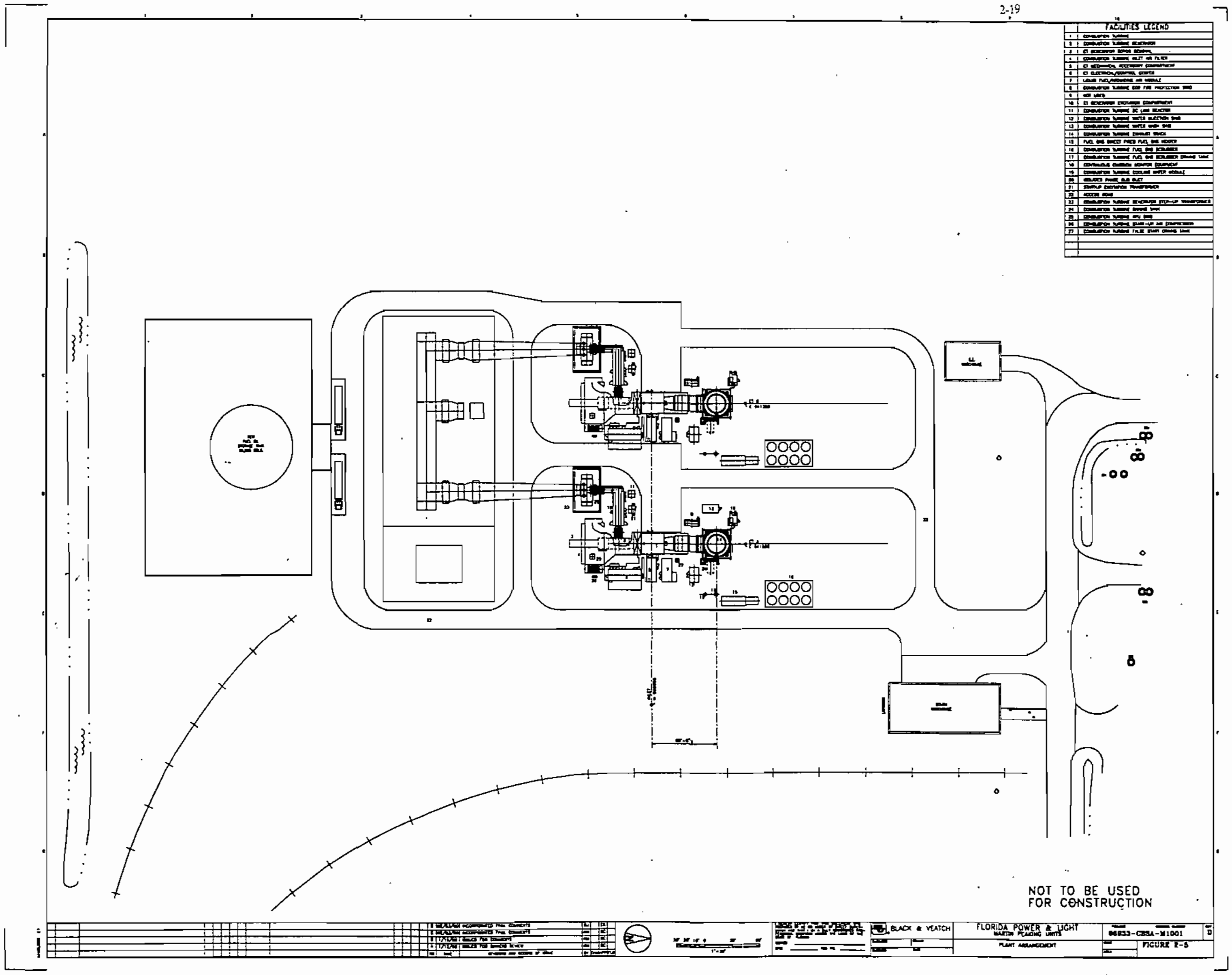
NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-4
Simplified Flow Diagram of GE FRAME 7FA Combustion Turbine
Baseload, Winter Design Conditions

Process Flow Legend	
Solid/Liquid	——→
Gas	- - - -→
Steam	——→

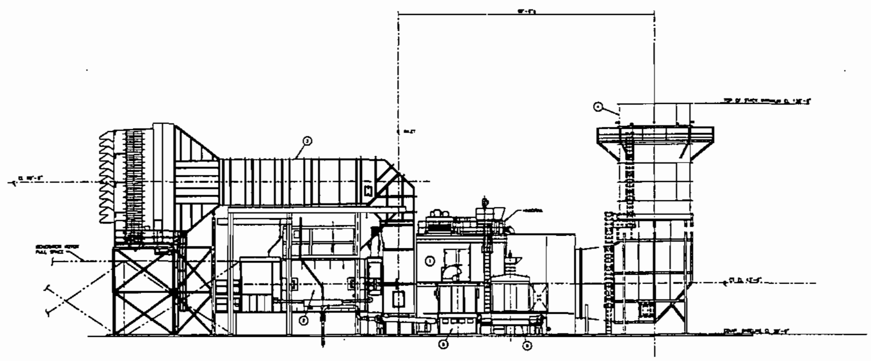
Filename: 9937614Y/F1/WP/FIGURES.VSD
Date: 2/11/00

Golder Associates


FACILITIES LEGEND
NOT TO BE USED
FOR CONSTRUCTION
BLACK & VEATCH
FLORIDA POWER & LIGHT
MARTIN PEAKING UNITS
PLANT ARRANGEMENT
FIGURE 2-5

EQUIPMENT IDENTIFICATION LIST

REF. No.	[illegible]	[illegible]
1		COMBUSTION TURBINE
2		GENERATOR
3		INLET AIR FILTER
4		STACK
5		ACCESSORY MODULE
6		FUEL OIL/ATOMIZING AIR MODULE
7		
8		
9		
10		
11		
12		
13		
14		
15		



SECTION A–A
(LOOKING WEST)

NOT TO BE USED
FOR GONSTRUCTION

BLACK & VEATCH

FLORIDA POWER & LIGHT
MARTIN PEAKING UNITS

PLANT ARRANGEMENT
TURBINE ELEVATION

FIGURE 2-8

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.

3.1 NATIONAL AND STATE AAQS

The existing national and Florida AAQS are presented in Table 3-1. Primary AAQS were promulgated to protect the public health with an adequate margin of safety [42 United States Code (USC) Section 7409(b)(1)]. The primary AAQS are designed to protect children, the elderly, and those with respiratory diseases. Secondary 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 [42 USC Section 7409(b)(2)]. 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 new or modified major sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a permit issued before the commencement of construction. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to DEP. For projects reviewed under the Power Plant Siting Act (PPSA) the PSD program is delegated.

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 tons per year (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.

Subject to certain exceptions, a "major modification" is defined under PSD regulations as a physical or operational change at an existing major facility that increases the facility's emissions by an amount that is greater than the defined significant emission rates. PSD significant emission rates are shown in Table 3-2.

EPA's regulations identify certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2 increments.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, *Prevention of Significant Deterioration of Air Quality*. The State of Florida has adopted PSD regulations which have been approved by EPA [Rule 62-212.400 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 GEP stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 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 BACT be applied to control emissions from the source (Rule 62-212.410, 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 52.21 (b)(12) and Rule 62-210.200(40), F.A.C., as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the Administrator, 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. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator 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 and shall provide for compliance by means which achieve equivalent results.

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

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

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

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

3.2.3 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). The source impact analysis for criteria pollutants that addresses compliance with AAQS and PSD Class II increments 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 the significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels (SILs) for Class I areas. The NPS, as the designated agency for oversight in air quality impacts to Class I areas, has also recommended significant impact levels for PSD Class I areas. The EPA proposed Class I SILs are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

[a] $\mu g/m^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD review, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

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 "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 fewer 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.

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.
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 [Rule 62-204.360(1) and (2), F.A.C.]. The minor source baseline for NO_2 has been set as March 28, 1988 [Rule 62-204.360(3), F.A.C.]. It should be noted that references to PM (TSP) are also applicable to PM_{10}.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(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 Florida DEP exempts 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 (Rule 62-212.400-3, F.A.C.).

3.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

Source information must be provided to adequately describe the proposed project. The general type of information required for this project is presented in Section 2.0.

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 Florida DEP (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 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 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.

3.2.6 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(o); Rule 62-212.400(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).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, 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 Rule 62-2.500(2)(c)2.a., F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of NSR 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 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The proposed project will be subject to one or more NSPS. The CTs will be subject to 40 CFR Part 60, Subpart GG. The tank will be subject to 40 CFR 60, Subpart Kb. There are no applicable NSPS for direct fired heaters.

3.4.1.1 Combustion Turbine

The CTs will be subject to emission limitations covered under Subpart GG, which limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour [10 million British thermal units per hour (mmBtu/hr)], based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15 percent oxygen and heat rate while sulfur dioxide emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notification, record keeping, reporting, performance testing and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(2) Notification of the date of initial start-up - no more than 60 days or less than 30 days prior to date.

(a)(3) Notification of actual date of initial start-up - within 15 days after such date.

(a)(5) Notification of date which demonstrates continuous emission monitoring (CEM) - not less than 30 days prior to date.

60.7 (b) Maintain records of the start-up, shutdown, and malfunction quarterly.

(c) Excess emissions reports - by the 30th day following end of quarter. (required even if no excess emissions occur)

(d) Maintain file of all measurements for two years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations

(a) continuous monitoring system required for water-to-fuel ratio to meet NSPS; system must be accurate within ±5 percent.

(b) Monitor sulfur and nitrogen content of fuel.

Oil - (1): each occasion that fuel is transferred to bulk storage tank.

Gas - (2): daily monitoring required

3.4.1.2 Fuel Oil Storage Tank

The applicable NSPS is 40 CFR 60, Subpart Kb--Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984). The storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb. There are no emission limiting or control requirements under Subpart Kb for the use of distillate fuel oil. The facility, however, must perform record keeping of the type of organic liquid in the tank.

3.4.2 FLORIDA RULES

The Florida DEP regulations for new stationary sources are covered in the F.A.C. The Florida DEP has adopted the EPA NSPS by reference in Rule 62-204.800(7); subsection (b)39 for stationary gas turbines. Therefore, the project is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. DEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

The Florida DEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.052, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The Florida DEP has published guidelines (DEP, 1995) to determine whether any emission of a potentially hazardous or toxic pollutant can pose a possible health risk to the public. Maximum concentrations for all regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants can be compared to ambient reference concentrations (ARCs) for each applicable pollutant. If the maximum predicted concentrations for any hazardous pollutant is less than the corresponding ARC for each applicable averaging time, that emission is considered not to pose a significant health risk. The ARCs are not environmental standards but, rather, evaluation tools to determine if an apparent threat to the public health may exist. These levels are not used in permitting new sources.

3.4.5 LOCAL AIR REGULATIONS

Martin County has not adopted its own air regulations.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The project site is located in Martin County, which has been designated by EPA and DEP as an attainment area for all criteria pollutants. Martin County and surrounding counties are designated as PSD Class II areas for SO_2, PM (TSP) , and NO_2. The nearest Class I areas to the site is the Everglades National Park (NP) which is about 144 km (89.9 miles) from the site.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The proposed project is considered to be a modification of a major facility because the potential emissions exceed the PSD major threshold and that potential emissions from at least one regulated pollutant emitted by the new project is estimated to exceed the TPY significant emission rate. Therefore, PSD review is required for each pollutant for which the emissions are considered major or exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions for NO_x, CO, PM (TSP), PM_{10}, SO_2, and sulfuric acid mist exceed the PSD significant emission rate. Because the proposed project's impacts for these pollutants are predicted to be below the significant impact levels, a modeling analysis incorporating the impacts from other sources is not required. (Note: EPA has promulgated changes to the PSD Rules to eliminate hazardous air pollutants (HAPs) from PSD review. The pollutants, vinyl chloride, mercury, asbestos, and beryllium, are no longer evaluated in PSD review.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed project's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I areas to the plant site is about 144 km from the site. A PSD Class I increment-consumption analysis is required because the project's impacts are greater than the proposed EPA Class I significant impact levels.

3.5.2.2 Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG. The proposed emissions for the turbines will be well below the specified limits (see Section 4.0). The storage tank will only contain distillate fuel oil requiring no recordkeeping.

3.5.2.3 Ambient Monitoring

Based on the estimated pollutant emissions from the proposed plant (see Table 3-4), a pre-construction ambient air quality monitoring analysis is required for PM_{10}, SO_2, NO_2, CO, and O_3 (based on VOC emissions). If the net increase in impact of the pollutant is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement may be obtained [52.21(i)(8)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If pre-construction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data or the collection of onsite data.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels and criteria. Therefore, the project is exempt from the preconstruction ambient air quality monitoring requirements.

3.5.2.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The CT stacks for the project will be 60 ft. This stack height does not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CTs' emissions caused by nearby structures are included in the modeling analysis.

3.5.3 NONATTAINMENT REVIEW

The project site is located in Martin County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CAA REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), an allowance system (Part 73), CEM (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the later of January 1, 2000, or the date on which the unit begins serving an electric generator (greater than 25 MW).

The permit would provide SO_2 and NO_x emission limitations and the requirement to hold emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded. For the proposed project, SO_2 allowances will be obtained from the market.

CEM for SO_2 and NO_x is required for gas-fired and oil-fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

Pollutant	Averaging Time	AAQS ($\mu g/m^3$) Primary Standard	AAQS ($\mu g/m^3$) Secondary Standard	AAQS ($\mu g/m^3$) Florida	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	Significant Impact Levels ($\mu g/m^3$) [b]
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[a]	365	NA	260	5	91	5
	3-Hour Maximum[a]	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum[a]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[a]	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	8-Hour Maximum[d]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

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

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors). These standards have been stayed by a court case against EPA; implementation of these standards appears to be years away.

[d] 0.08 parts per million (ppm); achieved when 3-year average of 99th percentile is 0.08 ppm or less. These have been stayed by a court case against EPA. EPA is appealing. The 1-hour standard of 0.12 ppm is still applicable. FDEP has not yet adopted the new standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.; 40 CFR 50; 40 CFR 52.21.; Chapter 62-204, 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] (μg/m3)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM (TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	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
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	$3.5x10^{-6}$	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

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 established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = micrograms per cubic meter.
MWC = Municipal waste combustor
MSW = Municipal solid waste

[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.

Sources: 40 CFR 52.21.
Rule 62-212.400

Table 3-3. Maximum Emissions Due to the Proposed Martin Simple Cycle CT Project Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions (TPY)		PSD Review
	Potential Emissions from Proposed Facility[a]	Significant Emission Rate	
Sulfur Dioxide	63.8	40	Yes
Particulate Matter [PM (TSP)]	37.9	25	Yes
Particulate Matter (PM_{10})	37.9	15	Yes
Nitrogen Dioxide	422.9	40	Yes
Carbon Monoxide	170.3	100	Yes
Volatile Organic Compounds	13.1	40	No
Lead	0.01	0.6	No
Sulfuric Acid Mist	4.9	7	No
Total Fluorides	0.03	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	0.0006	0.1	No
MWC Organics (as 2,3,7,8-TCDD)	0.000000371	0.0000035	No
MWC Metals (as Be, Cd)	0.003	15	No
MWC Acid Gasser (as HCl)	0.20	40	No

Note: NEG = Negligible.

[a] Based on emissions from two CTs operating at baseload at 59°F; firing natural gas (base and HPM) and distillate fuel oil for 2,890 and 500 hours per year per turbine, respectively (Refer to Table 2-8).

Table 3-4. Predicted Net Increase in Impacts Due to the Proposed Martin Simple Cycle CT Project Compared to PSD *De Minimis* Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$)	
	Predicted Increase in Impacts[a]	*De Minimis* Monitoring Concentration; Averaging Period
Sulfur Dioxide	0.51	13; 24-hour
Particulate Matter (PM_{10})	0.12	10; 24-hour
Nitrogen Dioxide	0.14	14; annual
Carbon Monoxide	1.6	575; 8-hour

Note: NA = not applicable.
NM = no ambient measurement method.
TPY = tons per year.

[a] See Section 6.0 for air dispersion modeling results.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted in amounts that are greater than the PSD significant emission rates shown in Table 3-2. In this case, the control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO_2, CO, and PM/PM_{10} (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed GE 7FA CTs are summarized below (see Table 2-7):

Pollutant Emissions (TPY)

Pollutant	2 GE 7FA CTs
NO_x	414.9
SO_2	63.9
CO	164.3
PM/PM_{10}	37.4

[a] Maximum emissions based on firing natural gas (base and HPM) for 2,890 hours and distillate fuel oil for 500 hours at baseload conditions and 59°F.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring a top-down approach. 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); and Rule 62-210.200(42), and Rule 62-214.410, F.A.C.]. The analysis must, by definition, be specific to the project (i.e., case-by-case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15 percent oxygen. For the CTs being considered for the project, the NSPS emission limit NO_x with the NSPS heat rate correction is 110.3 parts per million (ppm) on gas and 102.0 ppm (corrected to 15 percent oxygen) on oil at a fuel-bound nitrogen content of 0.015 percent. The proposed NO_x emission limits for the project will be much lower than the NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 PROPOSED BACT

In recent permitting actions, FDEP has established BACT for heavy-duty industrial gas turbines used in peaking mode like the ones proposed for the Martin Simple Cycle CT Project. DEP's decisions have been based on the use of advanced DLN combustors for limiting NO_x and CO emissions and clean fuels (natural gas and distillate oil) for control of other emissions, including SO_2. The BACT proposed for the CTs to be used for the project is consistent with these recent FDEP permits. The proposed project will have two modes of operation (see Section 2.3) for which a BACT analysis has been performed. The results of the analysis have concluded that the following controls are BACT for the project.

1. Natural Gas Fired. The CTs will utilize state-of-the-art DLN combustion technology which will achieve gas turbine exhaust NO_x levels of no greater than 10.5 ppmvd (corrected to 15 percent O_2). CO emissions will be limited to 12 ppmvd at baseload.
2. Fuel Oil Fired. The CT will utilize water injection to achieve gas turbine exhaust NO_x levels of no greater than 42 ppmvd (corrected to 15 percent O_2). CO emissions will be limited to 20 ppmvd at baseload.
3. Higher Power Modes (HPM). The CTs will utilize DLN technology, while operating in peak and power augmentation modes to limit NO_x to 15 ppmvd (at 15-percent O_2). CO will be limited to 15 ppmvd.

4.3.2 NITROGEN OXIDES

4.3.2.1 Introduction

The BACT analysis was performed for the following alternatives:

1. Advanced DLN combustors at an emission rate of 10.5 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil.

2. Selective catalytic reduction (SCR) and advanced DLN combustors at an emission rate of approximately 4 ppmvd corrected to 15 percent O_2 when firing natural gas and 16 ppmvd when firing oil.

Appendix B presents a discussion of NO_x control technologies and their feasibility for the project.

DLN combustor technology has recently been offered and installed by manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. NO_x emissions of 25 ppmvd (corrected to 15 percent O_2) and less have been offered by manufacturers for advanced CTs. Advanced in this context are the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) CTs. This technology is truly pollution prevention because NO_x emissions are inhibited from forming.

SCR is a post-combustion process where NO_x in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. The reaction occurs typically between 600°F and 750°F, which has limited SCR application to combined cycle units where such temperatures occur in the heat-recovery steam generator (HRSG). Exhausts from simple cycle operation range up to 1,200°F, thus limiting SCR application for this mode of operation. If SCR is used, with the higher cost ceramic catalyst, temperatures up to 1,025°F are possible. Such SCR systems are referred to as "hot" SCR. To accommodate "hot" SCR in the "F" Class gas turbine, some gas cooling would be required to maintain temperatures below 1,025°F. In-duct cooling using about 110,000 actual cubic feet per minute (acfm) of ambient air would maintain temperatures at or below 1,025°F with turbine flow of about 2,600,000 acfm and up to 1,200°F temperatures in the exhaust gas. This approach could be accomplished with cooling ducts/fans. While such modifications are theoretically possible, such gas cooling and its effectiveness have not been demonstrated on a "F" Class simple cycle gas turbine. SCR has been primarily installed and operated on combined cycle facilities using catalysts with temperature ranges from 600-750°F and generally achieving 9 ppmvd (corrected to 15 percent O_2) or less while burning only natural gas.

Applications of SCR with oil firing are limited. Where oil firing has been attempted, catalyst poisoning and ammonium salt formation has occurred. Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic, and special precautions in materials and ammonia injection rates must be implemented to minimize their formation. Ammonia injected in the SCR system that does not react with NO_x is emitted directly into the atmosphere and referred to as ammonia slip. In general, SCR manufacturers guarantee ammonia slip to be no more than 9 ppmvd corrected to 15 percent oxygen. While SCR is technically feasible for the project, SCR has not been applied to a simple cycle advanced combustion turbine of the size proposed for this project or to a facility approved for the amount of oil firing that may occur in this case (see Appendix B).

All of the recent Florida simple cycle projects have been permitted with this technology, including the Oleander Power Project and IPS Vandolah Power Project. This technology has also been approved in other states including simple cycle projects in Georgia and North Carolina.

As discussed in Section 2.1, the proposed CTs will be fired primarily with natural gas. Distillate oil will be used as backup fuel, but not to exceed 500 hours per year. Table 4-1 presents a summary of emissions with DLN combustors and with DLN combustors and SCR assuming 39 percent operating capacity at an ambient temperature of 59°F. The NO_x removed using SCR would be 126.8 TPY when firing oil and natural gas. The NO_x removed when firing oil is based on 500 hours per year. The NO_x removed when firing natural gas is based on 2,890 hours of operation (base load and HPM).

4.3.2.2 Proposed BACT and Rationale

The proposed BACT for the project is advanced DLN combustion technology. The proposed NO_x emissions level using this technology is 10.5 ppmvd (corrected to 15 percent oxygen) when firing natural gas under baseload conditions and 15 ppmvd (corrected to 15-percent oxygen) for HPM. NO_x from oil firing will be controlled using water injection

(42 ppmvd corrected to 15 percent oxygen). This combination of control technologies is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. Table 4-2 summarizes these considerations which favor the DLN pollution prevention technology.
2. The estimated incremental cost of SCR is approximately $13,636 per ton of NO_x removed and is similar to the cost for other projects that have rejected SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
3. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary emissions (to replace the lost generation); and from the generation of potentially hazardous waste (i.e., spent catalyst). While NO_x emissions would be reduced by about 156 TPY per unit with SCR, the net emissions reduction would not be as great. There are three additional factors that must be considered:
   a. Ammonia slip would occur, and it may be as high as 47.7 TPY per unit.
   b. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 6.6 TPY per unit additional particulate matter may be formed.
   c. SCR will require energy for system operation and reduce the efficiency of the combustion turbine. This lost energy would have to be replaced because the proposed project would be an efficient peaking power plant while operating. Any peaking power plants replacing this lost energy would be lower on the dispatch list and inevitably more polluting. Conservatively, this lost energy would result in the emissions of an additional 4.3 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.
   d. The "net" cost effectiveness could be as high as $25,200 per ton of pollutant removed.
4. The energy impacts of SCR will reduce potential electrical power generation by more than 3.9 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 323 residential customers.

5. The proposed BACT (i.e., DLN combustion) provides the most cost effective control alternative, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). DLN combustion at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to conventional CTs, the use of GE Frame 7FA CTs will result in 10 to 15 percent less NO_x emission while producing the same amount of electricity. When compared to existing turbines, the proposed project will emit 5 to 10 times less emissions for the same amount of electricity.

The analyses of economic, environmental, and energy impacts follow.

4.3.2.3 Impact Analysis

Economic--The total capital costs of SCR for the proposed plant are $5,868,400 per CT. The total annualized cost of applying SCR with DLN combustion is $1,728,750. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the DLN combustors and water injection (for oil firing) is estimated at $13,636 per ton of NO_x removed.

Environmental--The maximum predicted NO_x impacts using the DLN technology are all considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$, annual average, and the AAQS of 100 $\mu g/m^3$, annual average. Indeed, the maximum annual impact for the project is less than 0.2 $\mu g/m^3$, which is less than 20 percent of the significant impact level. While additional controls beyond DLN combustors (i.e., SCR and SCR with water injection) would reduce emissions, the effect will not be significant and much less than 1 percent of the PSD increment and the AAQS for the project.

The use of DLN 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 up to 9 ppmvd corrected to 15 percent oxygen based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as

47.7 TPY/per unit for the project. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10}; up to 6.6 TPY/per unit could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the project. This power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-3. This table shows the emissions balance for the project with and without SCR. As shown, the net reduction in emissions with SCR when all criteria pollutants are considered will be 69 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were included in Table 4-3. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using DLN 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 regulations (40 CFR 261). In addition, SCR will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: CAA (Section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

Energy--Significant energy penalties occur with SCR. With SCR, the output of the CT may be reduced by about 0.50 percent over that of advanced low-NO_x combustors. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 2,922,900 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 949,200 kWh per yr. Taken together, the total lost generation and energy requirements of SCR of 3,872,100 kWh per year could supply the monthly electrical needs of about 323 residential customers. To replace this lost energy, an additional 37×10^{10} British thermal units per year (Btu/yr) or about 37 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--The proposed project will use an advanced heavy-duty industrial gas turbine with advanced DLN combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is DLN combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the proposed GE Frame 7FA advanced machine is about 170 MW compared to the 70 MW to 120 MW conventional machines. The higher initial firing temperature (i.e., 2,600°F) results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing lower air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_x emissions to 9 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air are premixed prior to ignition. This level of control will result in NO_x emissions of about $0.04\ lb/10^6$ Btu, which is 7.5 times less than the emissions generated from conventional fossil fuel-fired steam generators.

Since the purpose of the project is to produce electrical energy, and CT technology is rapidly advancing, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT. The heat rate of the GE 7FA machines will be about 9,360 Btu/kWh (LHV, 59°F, natural gas). In contrast, the heat rate for a new conventional CT is about 11,000 Btu/kWh. Therefore, the amount of total NO_x from the advanced CT will be more than 10-percent lower than a new conventional turbine for the same amount of generation. When compared to existing CT technology, the heat rate is more than 30-percent lower.

Also, the amount of NO_x control achieved by the DLN combustor on an advanced CT is considerably higher than that achieved by a conventional CT. Because of the higher firing initial temperatures, the advanced CT results in greater NO_x emission formation. Since the advanced machine has higher firing temperatures, the NO_x emissions without the use of DLN combustion technology are much higher than a conventional CT (greater than 180 ppmvd vs. 150 ppmvd). This results in an overall greater NO_x reduction on the advanced CT.

Since the new Martin CTs will be used in peaking service, the emissions when compared to other CTs will be substantially lower. This comparison is readily made when comparing emissions on a lb/MW-hr basis, i.e., the amount of pollutant generated for each MW-hr produced. For NO_x, the emissions from the GE Frame 7FA are 0.44 and 1.9 lb/MW-hr for gas and oil-firing, respectively. In contrast, the emissions existing CTs are more than 6.7 and 10.6 lb/MW-hr for gas and oil-firing, respectively. Even at emission levels at the NSPS, the emissions are more than 4.6 lb/MW-hr. The proposed project will potentially displace emissions from more inefficient turbines at rates 5 to 10 times lower.

4.3.3 CARBON MONOXIDE

4.3.3.1 Introduction

Emissions of CO are dependent upon the combustion design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing). The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO as well as NO_x emissions.

For the project, the following alternatives were evaluated as BACT:

1. Combustion controls at 12 ppmvd when firing natural gas (at baseload), 15 ppmvd for HPM and 20 ppmvd when firing oil (at baseload); and
2. Oxidation catalyst at 90 percent removal; maximum annual CO emissions are 8 TPY per unit.

4.3.3.2 Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed 12 ppmvd when firing natural gas, 15 ppmvd for HPM, and 20 ppmvd when firing distillate oil at baseload conditions. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts;
2. The economic impacts are significant (i.e., the capital cost is about $1.86 million per unit, with an analyzed cost of $585,600 per year per unit); and
3. Recent projects in Florida have been authorized with BACT emission limits of 25 ppmvd on gas and 90 ppmvd on oil.

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 produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 12 ppmvd range and higher. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

4.3.3.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $585,600 per unit, resulting in a cost effectiveness of greater than $7,900 per ton of CO removed. The cost effectiveness is based on 2,890 hours per year on natural gas (base load and HPM) and 500 hours per year of operation on oil. No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts at the proposed CT emission rate are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS. There would also be no secondary benefits, such as reductions in acidic deposition, to reducing CO.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,169,100 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 97 residential customers for a year. To replace this lost energy, about 1.1×10^{10} Btu/yr or about 11 million ft^3/yr of natural gas would be required.

4.3.4 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CT as a result of incomplete combustion. The VOC emissions will be limited through the use of combustion technology and the use of clean fuels so that emissions will not exceed 1.5 ppmvd when firing natural gas and 3.5 ppmvw when firing distillate oil. While BACT does not apply to VOC, the proposed emission levels are similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

4.3.5 PM/PM_{10}, SO_2 AND OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PM/PM_{10} emissions from the CTs are a result of incomplete combustion and trace elements 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 gas- or oil-fired CTs.

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 10 pounds per hour (lb/hr) when firing natural gas]} is less than 0.01 grain per standard cubic foot, which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

There are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil, represent BACT for these pollutants. The use of natural gas and very low sulfur (0.05 percent) fuel oil will limit emissions of SO_2 and sulfuric acid mist.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas and distillate oil represent BACT because of their inherently low contaminant content.

Table 4-1. NO_x Emission Estimates (TPY) of BACT Alternative Technologies (per Unit)

Alternative BACT Control Technologies	Operating Mode[a] Oil	Gas	Gas-HPM	Total
NO_x Emission (TPY)				
DLN only	88.6	90.8	28.1	207.5
DLN with SCR[b]	34.4	35.3	10.9	80.7
Reduction	(54.1)	(55.5)	(17.1)	(126.8)
Basis of Emissions (ppmvd)				
DLN only	42	10.5	15	
DLN with SCR	16	4	6	
Hours of Operation	500	2,390	500	3,390

Note: DLN = Dry low-NO_x.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Emission rates were based on a GE FRAME 7FA combustion turbine operating at 100-percent capacity and firing natural gas for 2,390 hours and distillate fuel oil for 1,000 hours. Emission data are based on an ambient temperature of 50°F at maximum emission rates.

[b] Based on primary emissions with SCR; no account is made for additional emissions (secondary) due to lost energy from heat rate penalty and electrical usage for SCR operation (see Table 4-3).

Table 4-2. Comparison of Alternative BACT Control Technologies for NO_x (per Unit)

	Alternative BACT Control Technologies	
	DLN Only	SCR
Technical Feasibility	Feasible	Marginally Feasible for gas
Economic Impact[a]		
Capital Costs	included	$5,868,300
Annualized Costs	included	$1,728,750
Cost Effectiveness		
NO_x Removed (per ton of NO_x)	NA	$13,636
NO_x Removed (per ton of total pollutants)	NA	$25,214
Environmental Impact[b]		
Total NO_x (TPY)	207.5	80.72
NO_x Reduction (TPY)	NA	(126.8)
Ammonia Emissions (TPY)	0	47.4
PM Emissions (TPY)	0	6.6
Secondary Emissions (TPY)	0	4.3
Net Emission Reduction (TPY)	NA	(68.6)
Energy Impacts[c]		
Energy Use (kWh/yr)	0	3,872,100
Energy Use (mmBtu/yr)		37,500
at 10,000 Btu/kWh	0	
Energy Use (mmcf/yr)		37
at 1,000 Btu/cf for natural gas	0	
Energy Use (residential customers)	0	323

[a] See Appendix B for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table 4-3.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 3,390 hours per year. Lost energy is based on 0.5 percent of 172.44 MW. SCR electrical usage is based on 0.080 MWh per SCR system and 0.20 MWh for cooling fan.

Table 4-3. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

Pollutants	Incremental Emissions (tons/year) of SCR Primary	Secondary	Total
Particulate	6.55	0.14	6.69
Sulfur Dioxide		0.05	0.05
Nitrogen Oxides	-126.78	2.50	-124.28
Carbon Monoxide		1.50	1.50
Volatile Organic Compounds		0.10	0.10
Ammonia	47.38		
Total:	-72.85	4.29	-68.56
Carbon Dioxide (additonal from gas firing)		2,375.06	2,375.06

Basis:

Lost Energy (mmBtu/year)	37,501

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

5.0 AMBIENT MONITORING ANALYSIS

The CAA requires that an air quality analysis be conducted for each criteria and noncriteria pollutant subject to regulation under the Act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Noncriteria pollutants are those pollutants that may be regulated by emission standards, but no AAQS have been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality.

A major source may waive the ambient monitoring analysis requirement if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels. The maximum impacts of the proposed source are compared with the PSD *de minimis* concentrations in Table 3-4. As can be seen from Table 3-4, the proposed plant's maximum air quality impacts will be well below the *de minimis* concentrations for all applicable pollutants.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

The general modeling approach in this case followed EPA and Florida DEP modeling guidelines for determining compliance with AAQS and PSD increments. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA significant impact levels at any off-plant property areas in the vicinity of the plant.

If the project's impacts are above the significant impact levels, then a more detailed air modeling analysis that includes background sources is performed. Current Florida DEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. Based on the screening modeling analysis results, additional modeling refinements with a denser receptor grid are performed, as necessary, to obtain the maximum concentration. Modeling refinements are performed with a receptor grid spacing of 100 meters (m) or less.

For this project, the significant impacts levels were calculated in the vicinity of the plant following Florida DEP policies.

Generally, if a new project also is within 150 km of a PSD Class I area, then a significant impact analysis is also performed for the PSD Class I area. Currently, the National Park Service (NPS) has recommended significant impact levels for PSD Class I areas. The recommended levels have not been promulgated as rules. EPA also has proposed PSD Class I significant impact levels that have not been finalized as of this report.

Because the proposed project site is approximately 144 km from the Everglades National Park PSD Class I area, a significant impact modeling analysis has been performed.

6.2 PRECONSTRUCTION MONITORING ANALYSIS APPROACH

The general modeling approach in this case followed EPA and Florida DEP modeling guidelines. The project's impacts were compared to the *de minimis* monitoring levels to determine whether it would be necessary to submit continuous monitoring data to DEP prior to construction. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a *de minimis* impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA *de minimis* levels at any off-plant property areas in the vicinity of the plant. Current Florida DEP policies stipulate that the highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

A proposed major stationary facility or major modification may be exempt 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.

For this project, the project's impacts were calculated in the vicinity of the plant for comparison to *de minimis* levels following Florida DEP policies. As presented in Section 5.0, since the project's VOC emissions are lower than the *de minimis* VOC emission level, the project is exempt from preconstruction ambient monitoring requirements.

6.3 AIR MODELING ANALYSIS APPROACH

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, for each pollutant which is emitted above the significant emission rate, air modeling analyses are required to determine if the project's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels. These analyses consider the project's impacts alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest annual and the highest short-term concentrations for comparison to the significant impact levels and *de minimis* levels.

If the project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations, and calculate the cumulative impact of these sources for comparison to ambient standards. In general, when 5 years of meteorological data are used in the analysis, the highest annual and the HSH concentrations are compared to the applicable AAQS and allowable PSD increments. 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 air quality standards and allowable PSD increments, 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 proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor at which the maximum concentration was predicted. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements employ an angular spacing between radials of 2 degrees and a distance interval from 100 to 300 m, depending on the concentration gradient in the vicinity of the screening receptor to be refined. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid will extend to all adjacent screening receptors. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid highest concentration is obtained. A more detailed description of the model, along with the emission inventory, meteorological data, and screening receptor grids are presented in the following sections.

6.3.2 MODEL SELECTION

The Industrial Source Complex Short-term (ISCST3, Version 99155) dispersion model (EPA, 1999) was used to evaluate the pollutant impacts due to the proposed CTs. This model is maintained by the EPA on its Internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can run in the rural or urban land use mode which affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent of the land use within a 3-km radius around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land-use within a 3-km radius of the FPL Martin plant site (see Figure 2-1), the rural dispersion coefficients were used in the modeling analysis.

The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. When evaluating the project's impacts only for comparison to the significant impact and *de minimis* monitoring levels, a generic emission rate of 10 grams per second (g/s) was used as emissions for the proposed source. Maximum pollutant-specific air impacts for the project were then determined by multiplying the maximum pollutant-specific emission rate, in pounds per hour, by the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

6.3.3 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 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) station at the Palm Beach International Airport at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. These data are the most recent 5-year period of meteorological data that have been approved by DEP for use in the modeling. The NWS station at West Palm Beach is located approximately 45 km (28 miles) southeast of the Martin plant site. The meteorological data from West Palm Beach are assumed to be representative of the project site because both the project site and the weather station are located in similar topographical areas and are situated in southern Florida to experience similar weather conditions, such as frontal passages.

6.3.4 EMISSION INVENTORY

A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs used in the air modeling analysis is presented in Tables 2-1 through 2-6. The emission and stack operating parameters presented for 35/32°F and 95°F ambient temperatures for both natural gas and distillate fuel oil were used in the modeling to determine the maximum air quality impacts for a range of possible operating conditions.

The following nine modeling scenarios were considered for each fuel type:

1. Base operating load at an inlet temperature of 35°F;
2. Base operating load at an inlet temperature of 59°F;
3. Base operating load at an inlet temperature of 95°F;
4. 75 percent operating load at an inlet temperature of 35°F;
5. Base operating load at an inlet temperature of 59°F;
6. 75 percent operating load at an inlet temperature of 95°F;
7. 50 percent operating load at an inlet temperature of 35°F; and
8. Base operating load at an inlet temperature of 59°F;
9. 50 percent operating load at an inlet temperature of 95°F.

In addition, the following three modeling scenarios were also considered for natural gas firing only, making a total of 12 scenarios for natural gas firing;

10. Higher Power Mode (HPM), base inlet temperature of 35°F ;
11. HPM, base inlet temperature of 59°F; and
12. HPM, base inlet temperature of 95°F;

The proposed CTs will have a stack height of 60 ft and an inner stack diameter of 22 ft.

6.3.5 RECEPTOR LOCATIONS

For predicting maximum concentrations in the vicinity of the plant, a polar receptor grid comprised of 693 grid receptors was used. These receptors included 36 receptors located on radials extending out from the proposed CTs' stack locations. Along each radial, receptors were located at the plant property and distances of 0.2, 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 5.0, 6.0, 8.0, 10.0, 12.0, 14.0, 16.0, 18.0, 20.0, 22.0, 24.0, 27.0, and 30.0 km from the midpoint between the two proposed CT stacks.

Modeling refinements were performed for the worst-case loads and fuel only, by employing a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of 0.5 to 2 degrees.

Since the terrain surrounding the proposed plant site varies little from the stack base elevation of 50 ft above MSL, the terrain was assumed to be flat and receptor elevations were set equal to the stack base elevation.

6.3.6 BUILDING DOWNWASH EFFECTS

The only significant structures in the vicinity of the proposed CT stacks are the proposed CT air filter inlets and the CT structures. The height and widths of these structures are as follows:

Structure	Height (ft)	Width (ft)	Length (ft)
CT air inlet	55	20	48
CT structure	22	30	36

Building dimensions for the project's structures were entered into the EPA's Building Profile Input Program (BPIP, Version 95086) for the purpose of obtaining direction-specific building heights and widths for all downwash-affected sources. The direction-specific building dimensions were then input to the ISCST3 model as the building height and width for each of 36 ten-degree wind sectors. A summary of the direction-specific building dimensions used in the modeling is presented in Appendix C.

6.4 SIGNIFICANT IMPACT ANALYSIS RESULTS

6.4.1 SITE VICINITY

The modeling analysis results for the proposed CTs alone in the vicinity of the plant are summarized in Tables 6-2 through 6-6. The maximum pollutant concentrations predicted in the screening analysis for a single CT and two CTs firing natural gas are presented in Tables 6-2 and 6-3, respectively. Similarly, the maximum pollutant concentrations predicted for one and two CTs firing distillate fuel are presented in Tables 6-4 and 6-5, respectively.

Modeling refinements were performed in the site vicinity for the worst-case impacts for each pollutant/averaging time. These occurred during fuel oil firing. The refinement values are presented in Table 6-6.

As shown in the tables, the maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CTs are all below the significant impact levels. Because the proposed source will not have a significant impact upon the air quality in the vicinity of the plant site, more detailed modeling analyses for determining compliance with the AAQS and allowable PSD Class II increments are not required.

The maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CTs are also below the *de minimis* monitoring levels. Because the proposed source will not have predicted impacts greater than *de minimis* levels, preconstruction monitoring data are not required to be submitted as part of the PSD review.

6.4.2 AT THE EVERGLADES NP PSD CLASS I AREA

The modeling analysis results for the proposed CTs alone at the Everglades NP are summarized in Tables 6-7 through 6-10. The maximum pollutant concentrations predicted in the screening analysis for a single CT and two CTs firing natural gas are presented in Tables 6-7 and 6-8, respectively. A summary of maximum pollutant concentrations predicted for one and two CTs firing distillate oil are presented in Tables 6-9 and 6-10, respectively.

As shown in the tables, the maximum predicted SO_2, NO_2, and PM impacts due to the proposed CTs are all below EPA's proposed PSD Class I significant impact levels. Therefore, more detailed modeling analyses for determining compliance with allowable PSD Class I increments are not required for these pollutants.

A summary of the ISCST3 model results for each year are presented in Appendix D. An example of the model input file are also provided in Appendix D.

Table 6-1. Major Features of the ISCST3 Model, Version 99155

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• 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 including setting wind speeds less than 1 meters per second(m/s) to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term.
Source: EPA, 1999.

Table 6.2. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Natural Gas, at Site Vicinity

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature												Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)											
	Base Load			75% Load			50% Load			Higher Power Mode				Base Load			75% Load			50% Load			Higher Power Mode		
	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F		35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0138	0.0142	0.0150	0.0172	0.0175	0.0184	0.0208	0.0210	0.0218	0.0135	0.0138	0.0142
													24-Hour	0.1856	0.1892	0.1982	0.2205	0.2228	0.2297	0.2663	0.2678	0.2907	0.1829	0.1853	0.1897
													8-Hour	0.4403	0.4498	0.4732	0.5305	0.5366	0.5539	0.7092	0.7437	0.8592	0.4331	0.4395	0.4512
													3-Hour	0.8204	0.8383	0.8815	1.0723	1.1085	1.2145	1.6602	1.7230	1.9596	0.8075	0.8196	0.8414
													1-Hour	1.9387	2.0760	2.4072	3.2170	3.3254	3.6436	4.9805	5.1690	5.8788	1.8627	1.9555	2.1253
SO_2	5.1	4.9	4.5	4.1	4.0	3.6	3.3	3.2	2.9	5.3	5.1	4.8	Annual	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
													24-Hour	0.012	0.012	0.011	0.011	0.011	0.010	0.011	0.011	0.011	0.012	0.012	0.011
													3-Hour	0.053	0.052	0.049	0.056	0.055	0.055	0.069	0.069	0.071	0.054	0.053	0.051
NO_x	79.4	76.0	68.8	63.3	61.0	55.9	50.1	48.5	44.7	116.7	112.4	106.0	Annual	0.014	0.014	0.013	0.014	0.013	0.013	0.013	0.013	0.012	0.020	0.020	0.019
PM10	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	Annual	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.002	0.002	0.002
													24-Hour	0.023	0.024	0.025	0.028	0.028	0.029	0.034	0.034	0.037	0.023	0.023	0.024
CO	44.8	42.6	38.8	36.1	34.8	32.1	29.8	28.9	27.1	44.9	53.3	49.6	8-Hour	0.249	0.241	0.231	0.241	0.235	0.224	0.266	0.271	0.293	0.245	0.295	0.282
													1-Hour	1.094	1.114	1.177	1.463	1.458	1.474	1.870	1.882	2.007	1.054	1.313	1.328

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6-3. Maximum Pollutant Concentrations Predicted for 2 Simple-Cycle Combustion Turbines on Natural Gas Compared to EPA Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)												EPA Significant Impact Levels (ug/m^3)
		Base Load			75% Load			50% Load			Higher Power Mode			
		35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	
SO_2	Annual	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	1
	24-Hour	0.024	0.023	0.022	0.023	0.022	0.021	0.022	0.022	0.021	0.024	0.024	0.023	5
	3-Hour	0.106	0.104	0.099	0.111	0.110	0.111	0.138	0.139	0.143	0.108	0.105	0.102	25
NO_x	Annual	0.028	0.027	0.026	0.027	0.027	0.026	0.026	0.026	0.025	0.040	0.039	0.038	1
PM10	Annual	0.003	0.004	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.003	0.003	0.004	1
	24-Hour	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.07	0.05	0.05	0.05	5
CO	8-Hour	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.6	0.5	0.6	0.6	500
	1-Hour	2.2	2.2	2.4	2.9	2.9	2.9	3.7	3.8	4.0	2.1	2.6	2.7	2,000

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6.4. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Fuel Oil, at Site Vicinity

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature										Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
	Base Load			75% Load			50% Load			Averaging	Base Load			75% Load			50% Load		
Pollutant	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	Time	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F
Generic	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0133	0.0138	0.0148	0.0169	0.0197	0.0180	0.0205	0.0206	0.0213
(10 g/s)										24-Hour	0.1817	0.1851	0.1958	0.2174	0.2572	0.2260	0.2637	0.2650	0.2707
										8-Hour	0.4298	0.4390	0.4671	0.5225	0.5846	0.5446	0.6723	0.7011	0.7965
										3-Hour	0.8010	0.8181	0.8703	1.0319	1.4093	1.1578	1.5873	1.6401	1.8217
										1-Hour	1.8143	1.9248	2.3160	3.0958	4.2279	3.4734	4.7618	4.9201	5.4650
SO_2	103.1	98.6	89.1	82.0	78.8	72.2	64.7	62.6	57.7	Annual	0.017	0.017	0.017	0.017	0.020	0.016	0.017	0.016	0.015
										24-Hour	0.236	0.230	0.220	0.225	0.255	0.206	0.215	0.209	0.197
										3-Hour	1.041	1.016	0.977	1.066	1.399	1.053	1.294	1.294	1.324
NO_x	370.6	354.3	316.1	291.5	280.4	256.6	228.2	220.8	203.3	Annual	0.062	0.061	0.059	0.062	0.070	0.058	0.059	0.057	0.055
PM10	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.003	0.003	0.003	0.004	0.004	0.004	0.004	0.004	0.005
										24-Hour	0.039	0.040	0.042	0.047	0.055	0.048	0.056	0.057	0.058
CO	75.6	71.8	64.6	71.2	68.9	64.4	86.1	84.0	79.7	8-Hour	0.409	0.397	0.380	0.469	0.507	0.442	0.729	0.742	0.800
										1-Hour	1.728	1.741	1.885	2.777	3.670	2.818	5.166	5.207	5.488

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6-5. Maximum Pollutant Concentrations Predicted for 2 Simple-Cycle Combustion Turbines on Fuel Oil at the Site Vicinity as Compared to EPA Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1): Base Load			75% Load			50% Load			EPA Significant Impact Levels (ug/m^3)
		35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	
SO_2	Annual	0.0347	0.0342	0.0331	0.0350	0.0391	0.0328	0.0334	0.0325	0.0309	1
	24-Hour	0.472	0.460	0.440	0.449	0.511	0.411	0.430	0.418	0.394	5
	3-Hour	2.081	2.033	1.954	2.132	2.799	2.107	2.588	2.587	2.649	25
NO_x	Annual	0.125	0.123	0.118	0.124	0.139	0.117	0.118	0.115	0.109	1
PM10	Annual	0.0057	0.0059	0.0063	0.0073	0.0084	0.0077	0.0088	0.0088	0.0091	1
	24-Hour	0.08	0.08	0.08	0.09	0.11	0.10	0.11	0.11	0.12	5
CO	8-Hour	0.82	0.79	0.76	0.94	1.01	0.88	1.46	1.48	1.60	500
	1-Hour	3.46	3.48	3.77	5.55	7.34	5.64	10.33	10.41	10.98	2,000

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.
NA = Not applicable

Table 6-6. Summary of Maximum Pollutant Concentrations Predicted for Two Combustion Turbines Compared to the EPA Class II Significant Impact Levels, PSD Class II Increments, and AAQS Refined Analysis

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3)	Receptor Location Relative to Site Origin Location: Direction (degrees)	Receptor Location Relative to Site Origin Location: Distance (meters)	EPA Class II Significant Impact Levels (ug/m^3)	PSD Class II Increments (ug/m^3)	AAQS (ug/m^3)
SO_2	Annual	0.040	299	10000	1	25	60
	24-Hour	0.51	310	11700	5	91	260
	3-Hour	2.8	90	500	25	512	1,300
NO_2	Annual	0.14	299	10000	1	25	100
PM10	Annual	0.009	299	10000	1	17	50
	24-Hour	0.12	40	300	5	30	150
CO	8-Hour	1.6	40	300	500	NA	10,000
	1-Hour	11.0	90	500	2,000	NA	40,000

NA= not applicable

Table 6.7. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Natural Gas, at Everglades National Park PSD Class I Area

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature													Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)											
	Base Load			75% Load			50% Load			Higher Power Mode			Averaging	Base Load			75% Load			50% Load			Higher Power Mode		
Pollutant	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	Time	32°F	59°F	95°F	32°F	59°F	95°F	32°F	59°F	95°F	32°F	59°F	95°F
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0014	0.0014	0.0015	0.0016	0.0016	0.0017	0.0018	0.0018	0.0018	0.0014	0.0014	0.0014
													24-Hour	0.0524	0.0528	0.0539	0.0563	0.0565	0.0576	0.0626	0.0630	0.0647	0.0520	0.0523	0.0529
													8-Hour	0.0988	0.0996	0.1016	0.1059	0.1065	0.1083	0.1180	0.1187	0.1221	0.0982	0.0988	0.0998
													3-Hour	0.2562	0.2592	0.2662	0.2824	0.2841	0.2887	0.3029	0.3040	0.3085	0.2540	0.2560	0.2597
													1-Hour	0.5342	0.5420	0.5607	0.6043	0.6089	0.6216	0.6610	0.6639	0.6768	0.5284	0.5337	0.5433
SO_2	5.1	4.9	4.5	4.1	4.0	3.6	3.3	3.2	2.9	5.3	5.1	4.8	Annual	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
													24-Hour	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.003	0.003	0.003
													3-Hour	0.017	0.016	0.015	0.015	0.014	0.013	0.013	0.012	0.011	0.017	0.016	0.016
NO_x	79.4	76.0	68.8	63.3	61.0	55.9	50.1	48.5	44.7	116.7	112.4	106.0	Annual	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.002
PM10	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	Annual	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
													24-Hour	0.007	0.007	0.007	0.007	0.007	0.007	0.008	0.008	0.008	0.007	0.007	0.007
CO	44.8	42.6	38.8	36.1	34.8	32.1	29.8	28.9	27.1	44.9	53.3	49.6	8-Hour	0.056	0.053	0.050	0.048	0.047	0.044	0.044	0.043	0.042	0.056	0.066	0.062
													1-Hour	0.302	0.291	0.274	0.275	0.267	0.251	0.248	0.242	0.231	0.299	0.358	0.340

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6-8. Maximum Pollutant Concentrations Predicted for 2 Simple-Cycle Combustion Turbines on Natural Gas at the Everglades National Park as Compared to Proposed EPA PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1): Base Load			75% Load			50% Load			Higher Power Mode			Proposed EPA Class I Significant Impact Levels (ug/m^3)
		35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	
SO_2	Annual	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.1
	24-Hour	0.007	0.007	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.007	0.007	0.006	0.2
	3-Hour	0.033	0.032	0.030	0.029	0.028	0.026	0.025	0.025	0.022	0.034	0.033	0.031	1.0
NO_x	Annual	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.004	0.004	0.004	0.1
PM10	Annual	0.0003	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0005	0.0005	0.0003	0.0003	0.0004	0.2
	24-Hour	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.3
CO	8-Hour	0.11	0.11	0.10	0.10	0.09	0.09	0.09	0.09	0.08	0.11	0.13	0.12	NA
	1-Hour	0.60	0.58	0.55	0.55	0.53	0.50	0.50	0.48	0.46	0.60	0.72	0.68	NA

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.
NA = Not applicable

Table 6-9. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Fuel Oil, at Everglades National Park PSD Class I Area

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature										Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
	Base Load			75% Load			50% Load			Averaging	Base Load			75% Load			50% Load		
Pollutant	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	Time	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0014	0.0014	0.0015	0.0016	0.0017	0.0017	0.0018	0.0018	0.0018
										24-Hour	0.0519	0.0523	0.0536	0.0560	0.0603	0.0568	0.0620	0.0623	0.0637
										8-Hour	0.0979	0.0987	0.1011	0.1053	0.1133	0.1073	0.1167	0.1173	0.1201
										3-Hour	0.2529	0.2558	0.2644	0.2802	0.2966	0.2863	0.3012	0.3021	0.3058
										1-Hour	0.5256	0.5332	0.5559	0.5984	0.6434	0.6148	0.6561	0.6586	0.6691
SO_2	103.1	98.6	89.1	82.0	78.8	72.2	64.7	62.6	57.7	Annual	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001
										24-Hour	0.067	0.065	0.060	0.058	0.060	0.052	0.051	0.049	0.046
										3-Hour	0.329	0.318	0.297	0.290	0.294	0.260	0.246	0.238	0.222
NO_x	370.6	354.3	316.1	291.5	280.4	256.6	228.2	220.8	203.3	Annual	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005
PM10	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
										24-Hour	0.011	0.011	0.011	0.012	0.013	0.012	0.013	0.013	0.014
CO	75.6	71.8	64.6	71.2	68.9	64.4	86.1	84.0	79.7	8-Hour	0.093	0.089	0.082	0.094	0.098	0.087	0.127	0.124	0.121
										1-Hour	0.501	0.482	0.452	0.537	0.559	0.499	0.712	0.697	0.672

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6-10. Maximum Pollutant Concentrations Predicted for 2 Simple-Cycle Combustion Turbines on Fuel Oil at the Everglades National Park as Compared to Proposed EPA PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)									Proposed EPA Class I Significant Impact Levels (ug/m^3)
		Base Load			75% Load			50% Load			
		35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	
SO_2	Annual	0.0035	0.0034	0.0033	0.0033	0.0034	0.0030	0.0029	0.0028	0.0026	0.1
	24-Hour	0.135	0.130	0.120	0.116	0.120	0.103	0.101	0.098	0.093	0.2
	3-Hour	0.657	0.636	0.594	0.579	0.589	0.521	0.491	0.476	0.445	1.0
NO_x	Annual	0.013	0.012	0.012	0.012	0.012	0.011	0.010	0.010	0.009	0.1
PM10	Annual	0.0006	0.0006	0.0006	0.0007	0.0007	0.0007	0.0008	0.0008	0.0008	0.2
	24-Hour	0.02	0.02	0.02	0.02	0.03	0.02	0.03	0.03	0.03	0.3
CO	8-Hour	0.19	0.18	0.16	0.19	0.20	0.17	0.25	0.25	0.24	NA
	1-Hour	1.00	0.96	0.90	1.07	1.12	1.00	1.42	1.39	1.34	NA

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

NA = Not applicable

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 INTRODUCTION

The additional impact analysis addresses the potential impacts of the new power facility on vegetation, soils, and wildlife of the surrounding area and the nearest Class I area. The nearest Class I area is the Everglades National Park, located approximately 144 km south of the proposed project. Because the facility is subject to the PSD NSR requirements for SO_2, PM_{10}, NO_2, CO, and sulfuric acid emissions, the additional impact analysis were performed for these pollutants. The analyses also addressed impacts associated with the project firing natural gas and backup distillate fuel oil.

According to the modeling results presented in Section 6.0, the maximum air quality impacts predicted for the project are well below the EPA's Class II significant impact levels, the PSD Class II increments, and the AAQS. The maximum air quality impacts predicted for the project are also below the EPA's Class I significant impact levels and the PSD Class I increments. As a result, regardless of the existing conditions in the vicinity of the site or in the Class I areas, the proposed project will not result in any significant adverse effects upon these areas.

7.2 SOIL, VEGETATION, AND AQRV ANALYSIS METHODOLOGY

As shown in Section 6.0, the maximum air quality impacts for the project were predicted in the vicinity of the project and in the Class I area. The analysis involved predicting worst-case maximum short- and long-term concentrations of pollutants and comparing them to the lowest observed effect levels for AQRVs or analogous organisms. In conducting the assessment, several assumptions were made to assess the pollutant interaction with the different matrices (i.e., vegetation, soils, wildlife, and aquatic environment).

A screening approach was used to evaluate potential effects that compared the maximum predicted ambient concentrations of air pollutants of concern with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the vicinity of the plant and the Class I area. It was recognized that effects threshold information is not available for all species found in the Everglades NP, although studies have been performed on a few of the common species and on other similar species which can be used as models.

7.3 IMPACTS TO PLANT VICINITY SOILS AND VEGETATION

According to the USDA Martin County Soil Survey, soils in the vicinity of the project are classified as Candler fine sand, an excessively drained, sloping soil found in the sandhill areas of Martin County. Excessively drained, sandy soils are by nature acidic, therefore agricultural uses require amendment of soil with lime to increase alkalinity.

Vegetative communities in the vicinity of the project site are primarily pine plantation, improved pasture, xeric oak hammock, and maintained lawns associated with the wastewater treatment plant and access road right-of-ways.

Maximum predicted concentrations of SO_2, PM_{10}, NO_2, and CO in the vicinity of the project site are at least an order of magnitude lower than the EPA Class II significant impact levels (see Table 6-4); therefore, no significant impacts associated with facility operations are expected. The predicted concentrations are less than 1 percent of the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area.

7.4 CLASS I AREA IMPACT ANALYSIS

7.4.1 IDENTIFICATION OF AQRV AND METHODOLOGY

An AQRV analysis was conducted to assess the potential risk to AQRVs of the Everglades-NP due to the modeled increase in emissions from the proposed facility. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> "All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a monument, preserve, or primitive area. They are the

assets that are to be preserved if the area is to achieve the purposes for which it was set aside" (Federal Register, 1978).

Except for visibility, AQRVs were not specifically defined. However, odor, soil, flora, fauna, cultural resources, geological features, water, and climate generally have been identified by land managers as AQRVs. Since specific AQRVs have not been identified for the Everglades National Park, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found in the Everglades NP.

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

- Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass
- Marsh Islands - cabbage palm and eastern red cedar
- Estuarine Habitat - black needlerush, salt marsh cordgrass, and wax myrtle
- Hardwood Swamp - red maple, red bay, sweet bay, and cabbage palm
- Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle, and saw palmetto
- Mangrove Swamp - red, white, and black mangrove

Wildlife AQRVs have been identified as endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles, and mammals.

A screening approach was used that compared the maximum predicted ambient concentration of air pollutants of concern in the Everglades NP (Table 7-1) with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted that specifically addressed the effects of air contaminants on plant species reported to occur in the park. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens, and species of the hardwood swamplands and mangrove forest, few specific citations that addressed these species were found. It is recognized that effect threshold information is not available for all species found in the Everglades National Park, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

7.4.2 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades NP are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. Entisols are shallow sandy soils overlying limestone, commonly found in sandhills and xeric pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of these soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Everglades National Park from the Martin County facility emissions precludes any significant impact on soils.

7.4.3 VEGETATION

7.4.3.1 General

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

The concentration of the pollutant, duration of exposure, and frequency of exposures influence the response of vegetation and wildlife to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively low ground-level concentrations which occur during certain meteorological conditions interspersed with long periods of extremely low to no ground-level concentrations. If there are any effects of stack emissions on plants and animals they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

7.4.3.2 SO_2

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$. Background concentrations in South Florida (Dade County) reported in 1999 averaged 0.001 $\mu g/m^3$, with a maximum of 0.003 $\mu g/m^3$. Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 $\mu g/m^3$.

Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 µg/m^3 for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 µg/m^3 SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

Two lichen species indigenous to Florida exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 µg/m^3 for 6 hours/week for 10 weeks (Hart et al., 1988).

The maximum 24-hour SO_2 concentrations predicted within the Class I area due to the project only are 0.007 µg/m^3 when operating with natural gas and 0.135 µg/m^3 when firing distillate fuel oil. When added to the maximum background concentration of 0.003 µg/m^3, total SO_2 impacts are 0.01 and 0.138 µg/m^3, for natural gas and distillate fuel oil, respectively. These levels are much lower than those known to cause damage to test species. Under worst-case scenarios when the plant is operating on backup fuel, the maximum 24-hour SO_2 concentrations predicted within the Class I area are only 0.03 to 0.07 percent of those that caused damage to the most sensitive lichens. The modeled annual incremental increase in SO_2 adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

7.4.3.3 PM_{10}

Although information pertaining to the effects of particulate matter on plants is scarce, some results are available. Ten species of native Indian plants were exposed to levels of particulate matter that ranged from 210 to 366 µg/m^3 for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of particulate matter lower than 163 µg/m^3 did not appear to be injurious to the tested plants (Mandoli and Dubey, 1988).

By comparison of these published toxicity values for particulate matter exposure (i.e., concentrations for an 8-hour averaging time), the possibility of plant damage in the Everglades NP can be determined. The maximum predicted cumulative 8-hour PM_{10}

concentration in the park due to the project only is 0.03 μg/m^3 when firing natural gas, and 0.05 μg/m^3 when firing distillate fuel oil (see Table 7-1). When added to the average background concentrations recorded in the vicinity of the NP (28 μg/m^3), the resultant concentrations are 13 percent of the lower threshold value that reportedly affects plant foliage. When added to the maximum PM_{10} concentrations recorded in the vicinity of the NP (57 μg/m^3), the worst case scenario concentrations are 57.03 and 57.05 μg/m^3 when firing natural gas or fuel oil, respectively. In any event, since the project contributes <1 μg/m^3, 8-hour average impact, to the total predicted impacts, no effects to vegetative AQRVs are expected from the project.

7.4.3.4 NO_2

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru et al., 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 μg/m^3 (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 μg/m^3 for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). The average and maximum background NO_2 concentrations reported in the vicinity of the Everglades NP are 0.018 and 0.108 μg/m^3, respectively.

Short term (8 hour averaging time) predicted NO_x emissions in the Class I area due to the project only are 0.289 and 0.914 μg/m^3 for natural gas and fuel oil, respectively. When added to the maximum background NO_2 concentrations reported in the vicinity of the Everglades NP (0.108 μg/m^3), these concentrations are less than 0.03 percent of the levels that cause foliar injury in acute exposure scenarios. By comparison of published toxicity values for NO_2 exposure to long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the Class I area can be examined for chronic exposure situations. For a chronic exposure, the annual estimated NO_2 concentrations due to the project only at the point of maximum impact in the Class I area are 0.004 and 0.013 $\mu g/m^3$ when the project is firing natural gas and fuel oil, respectively. These values are less than 0.001 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the national park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

7.4.3.5 CO

As with PM, information pertaining to the effects of CO on plants is scarce. The primary effect of high CO concentrations is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok et al. (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of $6.85 \times 10^6\ \mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of $6.85 \times 10^5\ \mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

By comparison of published effect values for CO exposure, the possibility of plant damage in the Class I areas can be determined. The predicted maximum annual concentrations due to the project only in the Class I area are 0.002 and 0.004 $\mu g/m^3$ for natural gas and fuel oil, respectively. These concentrations are <0.000001 percent of the minimum value that caused inhibition in laboratory studies.

7.4.3.6 SUMMARY

In summary, the phytotoxic effects from the proposed plant emissions are minimal. It is important to note that the elements were conservatively modeled with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.4.4 WILDLIFE

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National AAQS. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of SO_2, NO_2, and particulates which are reported to cause physiological changes are shown in Table 7-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from SO_2, NO_2, and particulates are expected. The proposed project's contribution to cumulative impacts is negligible.

7.5 IMPACTS UPON VISIBILITY

7.5.1 INTRODUCTION

A change in visibility is characterized by either a change in the visual range, defined as the greatest distance that a large dark object can be seen, or by a change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where

b_{exts} is the extinction coefficient calculated for the source, and

b_{extb} is the background extinction coefficient

The source extinction coefficient is determined from NO_x, SO_2, and PM_{10} emission's increase from the proposed project. The background extinction coefficient s for each area evaluated are based on existing ambient monitoring data. Based on predicted SO_4, NO_3, and PM_{10} concentrations, the increase in the project's emissions were compared a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

The modeling analysis determined the deciview change at receptors along a circle of 144 km. This represents the minimum distance of the Everglades NP PSD Class I area from the FPL Martin power plant site.

7.5.2 ANALYSIS METHODOLOGY

Following the recommendations of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report, a level II screening analysis was performed using the California Puff (CALPUFF) long-range transport model, along with an enhanced ISC meteorological data record. The CALPUFF postprocessor model CALPOST was used to summarize the maximum concentrations of SO_4, NO_3, and PM_{10} that were predicted with the CALPUFF model.

CALPUFF used in a manner recommended by the IWAQM Phase 2 Summary Report (EPA, 12/98). A summary of the parameter settings that were used in the CALPUFF model is presented in Table E-1 of Appendix E along with the IWAQM Phase 2 recommended parameter settings. The recommended parameter settings are presented in Appendix B of the IWAQM Phase II Summary Report. The CALPUFF model was used in an ISC screening mode with an "enhanced" ISCST3 meteorological data set.

The following CALPUFF settings/values were implemented in the Level II screening analysis:

- Use of six pollutant species of SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}.
- Use of MESOPUFF II scheme for chemical transformation with CALPUFF default background concentrations
- Include both dry and wet deposition and plume depletion
- Use Agricultural, unirrigated land use; minimum mixing height of 50 m
- Use transitional plume rise, stack-tip downwash, and partial plume penetration
- Use puff plume element dispersion, PG/MP coefficients, rural mode, and ISC building downwash scheme
- Use of partial plume path adjustment terrain effects
- Use highest predicted concentrations in 5 years for comparison to the maximum percent change in extinction

7.5.3 EMISSION INVENTORY

Based on recommendations of the IWAQM Phase II Report, the regional haze analysis considered only the maximum 24-hour increase in emissions due to the two proposed simple-cycle CT's. A summary of the maximum SO_2, NO_x and PM_{10} emission rates for the CT's are presented in Chapter 2. Based on the air modeling analysis, the maximum PSD Class I impacts for the project occurred base load, 35 degrees, and fuel oil firing. Emission rates used for the regional haze reflected this emission scenario.

7.5.4 BUILDING WAKE EFFECTS

The air modeling analysis included the same building structure dimensions to account for the effects of building-induced downwash as was used in the ISCST3 modeling analysis. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model.

7.5.5 RECEPTOR LOCATIONS

Receptors were located along a circle that was centered over the FPL Martin site with radii equal to the minimum distance (i.e., 144 km) from the Everglades NP PSD Class I Area. The circle was comprised of 180 polar receptors, spaced at 2-degree intervals. Because the area's terrain is flat, all receptors were assumed to be at zero elevation.

7.5.6 BACKGROUND VISUAL RANGES AND RELATIVE HUMIDITY FACTORS

The background extinction coefficient was based on data representative of the mean of the top 20-percentile air quality days. For the Everglades NP, a background extinction coefficient of 0.0466 km^{-1} was used, equating to a background visual range of 84 km. An annual relative humidity factor of 3.85 was also used for the analysis. These data values were provided by the National Park Service's Air Modeling Branch.

7.5.7 METEOROLOGICAL DATA

A five-year data record was used for years 1987 through 1991. The data set consisting of hourly surface observations and twice-daily mixing height data from the West Palm Beach National Weather Service (NWS) office, located at Palm Beach International Airport. The surface and upper data were preprocessed into an ASCII modeling format by EPA 's PCRAMMET meteorological preprocessing program. An anemometer height of 33 ft was used.

Additional meteorological parameters were added to the meteorological data records for use with the CALPUFF model. The addition parameters include friction velocity, Monin-Obukhov length, and surface roughness used for calculating dry deposition; precipitation type code and precipitation rate used for calculating wet deposition, and short-wave solar radiation and relative humidity use for calculating chemical transformation rates. The dry deposition parameters were added to the meteorological data records using the PCRAMMET model in dry deposition mode. Using the guidance provided in Section 3.1 of the PCRAMMET User's Manual (8/98), the following input values were selected:

1. Surface roughness at both application and measurement sites: 0.15 m
2. Noontime Albedo: 0.18

3. Bowen Ratio: 0.8
4. Anthropogenic Heat flux: 0
5. Minimum Monin-Obukhov Length: 2 m
6. Fraction of Net Radiation Absorbed by Ground: 0.15

Hourly precipitation amounts, relative humidity and short-wave radiation values were added separately to the meteorological data set. These parameters were obtained from West Palm Beach surface data available from Solar and Meteorological Surface Observation Network (SAMSON) data.

Based on the precipitation classification scheme provided in the CALPUFF User's Manual (EPA, 1995), each hour's precipitation code was set to 0 1, 2 or 3. An hour in which no precipitation occurred received a code of 0. If precipitation occurred, the code was set from 1 to 3, depending on the intensity. All precipitation was assumed to be in the form of rain.

7.5.8 CHEMICAL TRANSFORMATION

The air modeling analysis included all chemical transformation processes that occur for the emitted species.

7.5.9 RESULTS

The highest, second-highest (HSH) predicted 24-hour species concentrations in 5 years are summarized in Table 7-5. Each HSH predicted concentration was assumed to occur on the same day. The annual average relative humidity factor for the ENP is 3.85. Based on these factors, the maximum predicted change in visibility is summarized in Table 7-6. The predicted change in visibility is 4.83 percent, which are below the criteria value of 5 percent. Therefore, it is concluded that the proposed project will not adversely impact the background visibility levels at the Everglades NP PSD Class I area.

Table 7-1. Maximum Predicted Concentrations Due To Project Only at Everglades National Park

Natural Gas Operation

Pollutant	Concentrations[a] (ug/m^3) for Averaging Times				
	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.0002	0.007	ND	0.034	ND
Nitrogen Dioxide (NO_2)	0.004	ND	0.289	ND	ND
Particulates (PM_{10})	0.0005	0.02	0.03	ND	ND
Carbon Monoxide (CO)	0.002	ND	0.12	ND	0.68

Fuel Oil Operation

Pollutant	Concentrations[a] (ug/m^3) for Averaging Times				
	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.0035	0.135	ND	0.657	ND
Nitrogen Dioxide (NO_2)	0.013	ND	0.914	ND	ND
Particulates (PM_{10})	0.0008	0.03	0.05	ND	ND
Carbon Monoxide (CO)	0.004	ND	0.25	ND	1.42

[a]. From the ISC-PRIME model and 5-years of hourly meteorlogical data from Palm Beach International Airport, 1987-91

ND = Not determined

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level (μg/m³)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration 1-Hour	SO_2 Concentration 3-Hour	Plants
Sensitive	1,310 - 2,620 µg/m^3 (0.5 - 1.0 ppm)	790 - 1,570 µg/m^3 (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 µg/m^3 (1.0 - 2.0 ppm)	1,570 - 2,100 µg/m^3 (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 µg/m^3 (>2.0 ppm)	>2,100 µg/m^3 (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[1]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[2,3]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[1]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source: [1]Newman and Schreiber, 1988.
[2]Gardner and Graham, 1976.
[3]Trzeciak et al., 1977.

Table 7-5. Predicted Species Concentrations and Days

Species Predicted	Year	Concentration[a] (ug/m^3)	Julian Day
SO_4	1987	0.023375	213
	1988	**0.032071**	219
	1989	0.01875	33
	1990	0.024917	238
	1991	0.026201	178
NO_3	1987	**0.11568**	339
	1988	0.11026	156
	1989	0.11178	168
	1990	0.077229	322
	1991	0.10538	364
PM10	1987	0.019698	186
	1988	**0.023493**	5
	1989	0.019408	253
	1990	0.017778	317
	1991	0.023381	125

a. Predicted with CALPUFF model and ISCST3 meteorological data from West Palm Beach, 1987-91

Note: Values in bold indicated highest, second-highest species concentrations.

Table 7-6. Regional Haze Screening Analysis Results, FPL Martin - 2 Simple-Cycle CTs, Oil Firing

Item	Units	Value
Maximum Predicted Concentrations(a)	ug/m^3	
PM10		0.023493
SO_4		0.032071
NO_3		0.115680
Computed Concentrations	ug/m^3	
$(NH_4)_2SO_4$		0.044098
NH_4NO_3		0.1492
Average Relative Humidity Factor(b)		3.85
Background Visual Range(b), Vr		84
Background Extinction Coeff.(bext)	km^{-1}	0.0466
Source Extinction Coeff (bexts)	km^{-1}	
$(NH_4)_2SO_4$		0.000509
NH_4NO_3		0.001724
PM10		0.000070
Total bexts	km^{-1}	0.002303
Deciview Change		0.483
Percent Change (%)		4.83
Allowable Criteria (%)		5.0

a) Concentrations are highest, second-highest predicted in 5-years
a) Data provided by NPS, Air Resources Div., Facimile of 5/26/99

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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON GE FRAME 7FA COMBUSTION TURBINE

(Note: SO_2 typically results from 0.2 grams sulfur (grs)/100 cf of H_2S. Actual total sulfur based on 1 grs/100 cf to account for odorant (mercaptans) in pipeline gas.)

Table A-1. Design Information and Stack Parameters for Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	181.64	172.44	163.14	149.74
Net heat rate (Btu/kWh, LHV)	9,213	9,280	9,412	9,666
(Btu/kWh, HHV)	10,227	10,301	10,447	10,729
Heat Input (MMBtu/hr, LHV)	1,674	1,600	1,536	1,447
(MMBtu/hr, HHV)	1,858	1,776	1,704	1,607
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	4,113,660	3,928,290	3,793,980	3,615,270
- provided	3,706,000	3,539,000	3,418,000	3,257,000
Temperature (°F)	1,095	1,116	1,128	1,143
Moisture (% Vol.)	7.56	8.39	9.04	9.92
Oxygen (% Vol.)	12.60	12.44	12.36	12.27
Molecular Weight	28.49	28.39	28.33	28.22
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,674	1,600	1,536	1,447
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	80,322	76,808	73,698	69,470
CT Stack				
CT- Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions (CT Stack-Unit 4 only)				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	4,113,660	3,928,290	3,793,980	3,615,270
Temperature (°F)	1,095	1,116	1,128	1,143
Molecular weight	28.49	28.39	28.33	28.22
Volume flow (acfm)- calculated	2,731,204	2,652,303	2,587,410	2,497,848
(ft3/s)- calculated	45,520	44,205	43,123	41,631
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,095	1,116	1,128	1,143
CT volume flow (acfm)	2,731,204	2,652,303	2,587,410	2,497,848
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	119.7	116.3	113.4	109.5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000.

Table A-2. Maximum Emissions for Criteria Pollutants for FPL Sanford Repowering Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	10	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0	10.0
(TPY)	17.0	17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,793,537	1,715,087	1,645,639	1,551,219
Sulfur content (grains/ 100 cf)	1	1	1	1
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	5.1	4.9	4.7	4.4
(TPY)	8.69	8.31	7.97	7.51
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	10.5	10.5	10.5	10.5
Moisture (%)	7.56	8.39	9.04	9.92
Oxygen (%)	12.6	12.44	12.36	12.27
Turbine Flow (acfm)	2,731,204	2,652,303	2,587,410	2,497,848
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,143
Emission rate (lb/hr)	79.4	76.0	72.9	68.8
(TPY)	134.6	128.7	123.6	116.5
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	15	15	15	15
Moisture (%)	7.56	8.39	9.04	9.92
Turbine Flow (acfm)	2,731,204	2,652,303	2,587,410	2,497,848
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,143
Emission rate (lb/hr)	56.1	53.2	51.2	48.5
(TPY)	95.0	90.2	86.7	82.1
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	1.5	1.5	1.5	1.5
Moisture (%)	7.56	8.39	9.04	9.92
Turbine Flow (acfm)	2,731,204	2,652,303	2,587,410	2,497,848
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,143
Emission rate (lb/hr)	3.20	3.04	2.92	2.77
(TPY)	5.4	5.2	5.0	4.7
Lead (lb/hr)= NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 2000; EPA, 1996

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1.86E+03	1.78E+03	1.70E+03	1.61E+03
Emission Rate (lb/hr)	2.23E-09	2.13E-09	2.05E-09	1.93E-09
(TPY)	3.78E-09	3.61E-09	3.47E-09	3.27E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	1.39E-06	1.33E-06	1.27E-06	1.20E-06
(TPY)	2.36E-06	2.25E-06	2.16E-06	2.04E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	1,793,537	1,715,087	1,645,639	1,551,219
Sulfur (lb/hr)	2.56	2.45	2.35	2.22
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	5	5	5	5
Emission Rate (lb/hr)	0.39	0.38	0.36	0.34
(TPY)	0.67	0.64	0.61	0.58

Sources: (a) Golder Associates, 2000; (b) EPA, 1981; (c) Assumed.

Note: No Emission Factors for Hydrogen chloride (HCl) from natural gas firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	1.49E-03	1.42E-03	1.36E-03	1.29E-03
(TPY)	2.52E-03	2.41E-03	2.31E-03	2.18E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	34	34	34	34
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	6.32E-02	6.04E-02	5.79E-02	5.46E-02
(TPY)	1.07E-01	1.02E-01	9.82E-02	9.26E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1.86E+03	1.78E+03	1.70E+03	1.61E+03
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	10	10	10	10
Heat Input Rate (MMBtu/hr)	1,858	1,776	1,704	1,607
Emission Rate (lb/hr)	1.86E-02	1.78E-02	1.70E-02	1.61E-02
(TPY)	3.15E-02	3.01E-02	2.89E-02	2.72E-02

Sources: (a) Golder Associates, 2000; (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-5. Design Information and Stack Parameters for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	136.7	129.24	122.24	112.24
Net heat rate (Btu/kWh, LHV)	9,855	10,043	10,236	10,602
(Btu/kWh, HHV)	10,939	11,148	11,362	11,769
Heat Input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
(MMBtu/hr, HHV)	1,495	1,441	1,389	1,321
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	3,306,690	3,205,680	3,111,330	2,990,340
- provided	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Moisture (% Vol.)	7.49	8.27	8.92	9.8
Oxygen (% Vol.)	12.67	12.57	12.49	12.41
Molecular Weight	28.50	28.41	28.33	28.23
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	64,660	62,299	60,058	57,115
CT Stack				
CT- Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions (CT Stack-Unit 4 only)				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,306,690	3,205,680	3,111,330	2,990,340
Temperature (°F)	1,122	1,139	1,153	1,170
Molecular weight	28.50	28.41	28.33	28.23
Volume flow (acfm)- calculated	2,233,157	2,195,011	2,154,989	2,100,577
(ft3/s)- calculated	37,219	36,584	35,916	35,010
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,122	1,139	1,153	1,170
CT volume flow (acfm)	2,233,157	2,195,011	2,154,989	2,100,577
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	97.9	96.2	94.5	92.1

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000.

Table A-6. Maximum Emissions for Criteria Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	10	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0	10.0
(TPY)	17.0	17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,443,832	1,391,103	1,341,054	1,275,357
Sulfur content (grains/ 100 cf)	1	1	1	1
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	4.1	4.0	3.8	3.6
(TPY)	6.99	6.74	6.49	6.18
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	10.5	10.5	10.5	10.5
Moisture (%)	7.49	8.27	8.92	9.8
Oxygen (%)	12.67	12.57	12.49	12.41
Turbine Flow (acfm)	2,233,157	2,195,011	2,154,989	2,100,577
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
Emission rate (lb/hr)	63.3	61.0	58.9	55.9
(TPY)	107.3	103.4	99.8	94.7
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	12	12	12	12
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,233,157	2,195,011	2,154,989	2,100,577
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
Emission rate (lb/hr)	36.1	34.8	33.6	32.1
(TPY)	61.1	59.0	57.0	54.4
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	1.5	1.5	1.5	1.5
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,233,157	2,195,011	2,154,989	2,100,577
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
Emission rate (lb/hr)	2.58	2.48	2.40	2.29
(TPY)	4.4	4.2	4.1	3.9
Lead (lb/hr)= NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 2000; EPA, 1996

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
2,3,7,8-TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1.50E+03	1.44E+03	1.39E+03	1.32E+03
Emission Rate (lb/hr)	1.79E-09	1.73E-09	1.67E-09	1.59E-09
(TPY)	3.04E-09	2.93E-09	2.83E-09	2.69E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	1.12E-06	1.08E-06	1.04E-06	9.88E-07
(TPY)	1.90E-06	1.83E-06	1.76E-06	1.67E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	1,443,832	1,391,103	1,341,054	1,275,357
Sulfur (lb/hr)	2.06	1.99	1.92	1.82
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	5	5	5	5
Emission Rate (lb/hr)	0.32	0.30	0.29	0.28
(TPY)	0.54	0.52	0.50	0.47

Sources: (a) Golder Associates, 2000; (b) EPA, 1981; (c) Assumed.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for FPL Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	1.20E-03	1.15E-03	1.11E-03	1.06E-03
(TPY)	2.03E-03	1.95E-03	1.88E-03	1.79E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	34	34	34	34
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	5.08E-02	4.90E-02	4.72E-02	4.49E-02
(TPY)	8.62E-02	8.30E-02	8.00E-02	7.61E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1.50E+03	1.44E+03	1.39E+03	1.32E+03
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0

Table A-8. Maximum Emissions for Hazardous Air Pollutants for FPL Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	10	10	10	10
Heat Input Rate (MMBtu/hr)	1,495	1,441	1,389	1,321
Emission Rate (lb/hr)	1.50E-02	1.44E-02	1.39E-02	1.32E-02
(TPY)	2.53E-02	2.44E-02	2.35E-02	2.24E-02

Sources: (a) Golder Associates, 2000; (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-9. Design Information and Stack Parameters for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	91.1	86.5	81.34	74.64
Net heat rate (Btu/kWh, LHV)	11,820	12,050	12,415	12,866
(Btu/kWh, HHV)	13,120	13,375	13,780	14,281
Heat Input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
(MMBtu/hr, HHV)	1,195	1,157	1,121	1,066
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	2,726,160	2,659,560	2,592,960	2,516,370
- provided	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Moisture (% Vol.)	7.21	7.97	8.62	9.45
Oxygen (% Vol.)	12.99	12.90	12.83	12.80
Molecular Weight	28.51	28.43	28.35	28.25
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	51,682	50,026	48,467	46,091
CT Stack				
CT- Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions (CT Stack-Unit 4 only)				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,726,160	2,659,560	2,592,960	2,516,370
Temperature (°F)	1,168	1,184	1,195	1,200
Molecular weight	28.51	28.43	28.35	28.25
Volume flow (acfm)- calculated	1,893,520	1,871,057	1,841,472	1,798,783
(ft3/s)- calculated	31,559	31,184	30,691	29,980
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,168	1,184	1,195	1,200
CT volume flow (acfm)	1,893,520	1,871,057	1,841,472	1,798,783
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	83.0	82.0	80.7	78.9

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000.

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	10	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0	10.0
(TPY)	17.0	17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,154,037	1,117,062	1,082,231	1,029,181
Sulfur content (grains/ 100 cf)	1	1	1	1
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	3.3	3.2	3.1	2.9
(TPY)	5.59	5.41	5.24	4.98
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	10.5	10.5	10.5	10.5
Moisture (%)	7.21	7.97	8.62	9.45
Oxygen (%)	12.99	12.9	12.83	12.8
Turbine Flow (acfm)	1,893,520	1,871,057	1,841,472	1,798,783
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
Emission rate (lb/hr)	50.1	48.5	46.9	44.7
(TPY)	85.0	82.2	79.6	75.7
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	12	12	12	12
Moisture (%)	7.21	7.97	8.62	9.45
Turbine Flow (acfm)	1,893,520	1,871,057	1,841,472	1,798,783
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
Emission rate (lb/hr)	29.8	28.9	28.1	27.1
(TPY)	50.5	49.0	47.6	45.9
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	1.5	1.5	1.5	1.5
Moisture (%)	7.21	7.97	8.62	9.45
Turbine Flow (acfm)	1,893,520	1,871,057	1,841,472	1,798,783
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
Emission rate (lb/hr)	2.13	2.07	2.01	1.94
(TPY)	3.6	3.5	3.4	3.3
Lead (lb/hr)= NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 1998; EPA, 1996

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for FPL Simple Cycel CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
2,3,7,8-TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1.20E+03	1.16E+03	1.12E+03	1.07E+03
Emission Rate (lb/hr)	1.43E-09	1.39E-09	1.35E-09	1.28E-09
(TPY)	2.43E-09	2.35E-09	2.28E-09	2.17E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	8.94E-07	8.65E-07	8.38E-07	7.97E-07
(TPY)	1.52E-06	1.47E-06	1.42E-06	1.35E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	1,154,037	1,117,062	1,082,231	1,029,181
Sulfur (lb/hr)	1.65	1.60	1.55	1.47
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	5	5	5	5
Emission Rate (lb/hr)	0.25	0.24	0.24	0.23
(TPY)	0.43	0.41	0.40	0.38

Sources: (a) Golder Associates, 2000; (b) EPA, 1981; (c) Assumed.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	3,390	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	9.56E-04	9.26E-04	8.97E-04	8.53E-04
(TPY)	1.62E-03	1.57E-03	1.52E-03	1.45E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	34	34	34	34
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	4.06E-02	3.93E-02	3.81E-02	3.62E-02
(TPY)	6.89E-02	6.67E-02	6.46E-02	6.14E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1.20E+03	1.16E+03	1.12E+03	1.07E+03
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	10	10	10	10
Heat Input Rate (MMBtu/hr)	1,195	1,157	1,121	1,066
Emission Rate (lb/hr)	1.20E-02	1.16E-02	1.12E-02	1.07E-02
(TPY)	2.03E-02	1.96E-02	1.90E-02	1.81E-02

Sources: (a) Golder Associates, 2000; (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-13. Design Information and Stack Parameters for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	189.1	180.4	172.5	172.5
Net heat rate (Btu/kWh, LHV)	10,019	10,037	10,101	9,486
(Btu/kWh, HHV)	10,620	10,639	10,707	10,056
Heat Input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
(MMBtu/hr, HHV)	2,008	1,919	1,847	1,735
Fuel heating value (Btu/lb, LHV)	18,367	18,367	18,367	18,367
(Btu/lb, HHV)	19,469	19,469	19,469	19,469
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	4,286,820	4,088,130	3,942,720	3,702,960
- provided	3,862,000	3,683,000	3,552,000	3,336,000
Temperature (°F)	1,074	1,098	1,113	1,131
Moisture (% Vol.)	10.6	11.21	11.68	12.18
Oxygen (% Vol.)	11.19	11.06	11.00	11.00
Molecular Weight	28.39	28.33	28.27	28.21
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
Heat content (Btu/lb, LHV)	18,367	18,367	18,367	18,367
Fuel usage (lb/hr)- calculated	103,147	98,584	94,871	89,100
CT Stack				
CT - Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	4,286,820	4,088,130	3,942,720	3,702,960
Temperature (°F)	1,074	1,098	1,113	1,131
Molecular weight	28.39	28.33	28.27	28.21
Volume flow (acfm)- calculated	2,817,519	2,735,343	2,668,250	2,540,308
(ft3/s)- calculated	46,959	45,589	44,471	42,338
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,074	1,098	1,113	1,131
CT volume flow (acfm)	2,817,519	2,735,343	2,668,250	2,540,308
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	123.5	119.9	117.0	111.4

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	17	17	17	17
Emission rate (lb/hr)- provided	17.0	17.0	17.0	17.0
(TPY)	4.3	4.3	4.3	4.3
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)				
Fuel Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel use (lb/hr)	103,147	98,584	94,871	89,100
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	103.1	98.6	94.9	89.1
(TPY)	25.79	24.65	23.72	22.28
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10.6	11.21	11.68	12.18
Oxygen (%)	11.19	11.06	11	11
Turbine Flow (acfm)	2,817,519	2,735,343	2,668,250	2,540,308
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
Emission rate (lb/hr)	370.6	354.3	340.6	316.1
(TPY)	92.6	88.6	85.1	79.0
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10.6	11.21	11.68	12.18
Turbine Flow (acfm)	2,817,519	2,735,343	2,668,250	2,540,308
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
Emission rate (lb/hr)	75.6	71.8	69.0	64.6
(TPY)	18.9	17.9	17.2	16.1
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Turbine Flow (acfm)	2,817,519	2,735,343	2,668,250	2,540,308
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
Emission rate (lb/hr)	8.46	8.08	7.81	7.35
(TPY)	2.1	2.0	2.0	1.8
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0217	0.0207	0.0199	0.0187
(TPY)	0.0054	0.0052	0.0050	0.0047

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	2.01E+03	1.92E+03	1.85E+03	1.85E+03
Emission Rate (lb/hr)	7.63E-07	7.29E-07	7.02E-07	7.02E-07
(TPY)	1.91E-07	1.82E-07	1.75E-07	1.75E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.331	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	6.65E-04	6.35E-04	6.11E-04	6.11E-04
(TPY)	1.66E-04	1.59E-04	1.53E-04	1.53E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	32.54	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	6.53E-02	6.25E-02	6.01E-02	6.01E-02
(TPY)	1.63E-02	1.56E-02	1.50E-02	1.50E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (c) , lb/10^{12} Btu	2.11E+02	2.11E+02	2.11E+02	2.11E+02
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	4.24E-01	4.05E-01	3.90E-01	3.90E-01
(TPY)	1.06E-01	1.01E-01	9.75E-02	9.75E-02
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	1.26E-03	1.20E-03	1.16E-03	1.16E-03
(TPY)	3.14E-04	3.00E-04	2.89E-04	2.89E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	103,147	98,584	94,871	89,100
Sulfur (lb/hr)	51.57	49.29	47.44	44.55
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	5	5	5	5
Emission Rate (lb/hr)	7.90	7.55	7.26	6.82
(TPY)	1.97	1.89	1.82	1.71

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA, 1981; (c) 4 ppm assumed based on ASTM D2880
(d) assumed based on combustion estimates from GE

Table A-16. Maximum Emissions for Hazardous Air Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	1.59E-02	1.52E-02	1.46E-02	1.46E-02
(TPY)	3.97E-03	3.80E-03	3.65E-03	3.65E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.1	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	2.21E-03	2.11E-03	2.03E-03	2.03E-03
(TPY)	5.52E-04	5.28E-04	5.08E-04	5.08E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	6.51E-03	6.22E-03	5.98E-03	5.98E-03
(TPY)	1.63E-03	1.55E-03	1.50E-03	1.50E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	6.76	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	1.36E-02	1.30E-02	1.25E-02	1.25E-02
(TPY)	3.39E-03	3.24E-03	3.12E-03	3.12E-03
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	2	2	2	2
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	4.02E-03	3.84E-03	3.69E-03	3.69E-03
(TPY)	1.00E-03	9.60E-04	9.24E-04	9.24E-04
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	37	37	37	37
Heat Input Rate (MMBtu/hr)	2.01E+03	1.92E+03	1.85E+03	1.85E+03
Emission Rate (lb/hr)	7.43E-02	7.10E-02	6.83E-02	6.83E-02
(TPY)	1.86E-02	1.78E-02	1.71E-02	1.71E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	432	432	432	432
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	8.68E-01	8.29E-01	7.98E-01	7.98E-01
(TPY)	2.17E-01	2.07E-01	1.99E-01	1.99E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	1.73E-01	1.66E-01	1.59E-01	1.59E-01
(TPY)	4.33E-02	4.14E-02	3.99E-02	3.99E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	0.602451	0.5758026	0.554115	0.554115
(TPY)	0.15061275	0.14395065	0.13852875	0.13852875
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	23	23	23	23
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	4.62E-02	4.41E-02	4.25E-02	4.25E-02
(TPY)	1.15E-02	1.10E-02	1.06E-02	1.06E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	237	237	237	237
Heat Input Rate (MMBtu/hr)	2,008	1,919	1,847	1,847
Emission Rate (lb/hr)	4.76E-01	4.55E-01	4.38E-01	4.38E-01
(TPY)	1.19E-01	1.14E-01	1.09E-01	1.09E-01

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-17. Design Information and Stack Parameters for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	141.5	135.0	129.1	119.1
Net heat rate (Btu/kWh, LHV)	10,654	10,730	10,866	11,138
(Btu/kWh, HHV)	11,293	11,373	11,518	11,807
Heat Input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
(MMBtu/hr, HHV)	1,598	1,536	1,487	1,406
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	3,356,640	3,258,960	3,186,810	3,061,380
- provided	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Moisture (% Vol.)	10.23	10.68	11.06	11.54
Oxygen (% Vol.)	11.22	11.21	11.22	11.25
Molecular Weight	28.44	28.38	28.33	28.27
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	81,993	78,784	76,298	72,154
CT Stack				
CT - Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,356,640	3,258,960	3,186,810	3,061,380
Temperature (°F)	1,121	1,137	1,149	1,166
Molecular weight	28.44	28.38	28.33	28.27
Volume flow (acfm)- calculated	2,269,963	2,230,522	2,201,624	2,141,730
(ft3/s)- calculated	37,833	37,175	36,694	35,695
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,121	1,137	1,149	1,166
CT volume flow (acfm)	2,269,963	2,230,522	2,201,624	2,141,730
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	99.5	97.8	96.5	93.9

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000

Table A-18. Maximum Emissions for Criteria Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	17	17	17	17
Emission rate (lb/hr)- provided	17.0	17.0	17.0	17.0
(TPY)	4.3	4.3	4.3	4.3
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)				
Fuel Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel use (lb/hr)	81,993	78,784	76,298	72,154
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	82.0	78.8	76.3	72.2
(TPY)	20.50	19.70	19.07	18.04
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10.23	10.68	11.06	11.54
Oxygen (%)	11.22	11.21	11.22	11.25
Turbine Flow (acfm)	2,269,963	2,230,522	2,201,624	2,141,730
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
Emission rate (lb/hr)	291.5	280.4	271.4	256.6
(TPY)	72.9	70.1	67.9	64.2
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	24	24	24	24
Moisture (%)	10.23	10.68	11.06	11.54
Turbine Flow (acfm)	2,269,963	2,230,522	2,201,624	2,141,730
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
Emission rate (lb/hr)	71.2	68.9	67.2	64.4
(TPY)	17.8	17.2	16.8	16.1
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Turbine Flow (acfm)	2,269,963	2,230,522	2,201,624	2,141,730
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
Emission rate (lb/hr)	6.61	6.43	6.30	6.06
(TPY)	1.7	1.6	1.6	1.5
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0173	0.0166	0.0161	0.0152
(TPY)	0.0043	0.0041	0.0040	0.0038

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for FPL Martin Simple Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1.60E+03	1.54E+03	1.49E+03	1.49E+03
Emission Rate (lb/hr)	6.07E-07	5.83E-07	5.65E-07	5.65E-07
(TPY)	1.52E-07	1.46E-07	1.41E-07	1.41E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.331	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	5.29E-04	5.08E-04	4.92E-04	4.92E-04
(TPY)	1.32E-04	1.27E-04	1.23E-04	1.23E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	32.54	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	5.20E-02	5.00E-02	4.84E-02	4.84E-02
(TPY)	1.30E-02	1.25E-02	1.21E-02	1.21E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (c) , lb/10^{12} Btu	2.11E+02	2.11E+02	2.11E+02	2.11E+02
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	3.38E-01	3.24E-01	3.14E-01	3.14E-01
(TPY)	8.44E-02	8.11E-02	7.85E-02	7.85E-02
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	1.00E-03	9.61E-04	9.31E-04	9.31E-04
(TPY)	2.50E-04	2.40E-04	2.33E-04	2.33E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	81,993	78,784	76,298	72,154
Sulfur (lb/hr)	41.00	39.39	38.15	36.08
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	5	5	5	5
Emission Rate (lb/hr)	6.28	6.03	5.84	5.52
(TPY)	1.57	1.51	1.46	1.38

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA, 1981; (c) 4 ppm assumed based on ASTM D2880
(d) assumed based on combustion estimates from GE.

Table A-20. Maximum Emissions for Hazardous Air Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	1.26E-02	1.21E-02	1.18E-02	1.18E-02
(TPY)	3.16E-03	3.04E-03	2.94E-03	2.94E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.1	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	1.76E-03	1.69E-03	1.64E-03	1.64E-03
(TPY)	4.39E-04	4.22E-04	4.09E-04	4.09E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	5.18E-03	4.98E-03	4.82E-03	4.82E-03
(TPY)	1.29E-03	1.24E-03	1.20E-03	1.20E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	6.76	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	1.08E-02	1.04E-02	1.01E-02	1.01E-02
(TPY)	2.70E-03	2.60E-03	2.51E-03	2.51E-03
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	2	2	2	2
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	3.20E-03	3.07E-03	2.97E-03	2.97E-03
(TPY)	7.99E-04	7.68E-04	7.44E-04	7.44E-04
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	37	37	37	37
Heat Input Rate (MMBtu/hr)	1.60E+03	1.54E+03	1.49E+03	1.49E+03
Emission Rate (lb/hr)	5.91E-02	5.68E-02	5.50E-02	5.50E-02
(TPY)	1.48E-02	1.42E-02	1.38E-02	1.38E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	432	432	432	432
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	6.90E-01	6.63E-01	6.42E-01	6.42E-01
(TPY)	1.73E-01	1.66E-01	1.61E-01	1.61E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	1.38E-01	1.33E-01	1.28E-01	1.28E-01
(TPY)	3.45E-02	3.31E-02	3.21E-02	3.21E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	0.4794168	0.4606548	0.4461222	0.4461222
(TPY)	0.1198542	0.1151637	0.11153055	0.11153055
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	23	23	23	23
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	3.68E-02	3.53E-02	3.42E-02	3.42E-02
(TPY)	9.19E-03	8.83E-03	8.55E-03	8.55E-03
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	237	237	237	237
Heat Input Rate (MMBtu/hr)	1,598	1,536	1,487	1,487
Emission Rate (lb/hr)	3.79E-01	3.64E-01	3.52E-01	3.52E-01
(TPY)	9.47E-02	9.10E-02	8.81E-02	8.81E-02

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-21. Design Information and Stack Parameters for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	93.8	89.5	85.6	78.9
Net heat rate (Btu/kWh, LHV)	12,685	12,867	13,069	13,453
(Btu/kWh, HHV)	13,446	13,639	13,853	14,260
Heat Input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
(MMBtu/hr, HHV)	1,261	1,221	1,186	1,125
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	2,760,570	2,702,850	2,651,790	2,578,530
- provided	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Moisture (% Vol.)	9.29	9.77	10.17	10.6
Oxygen (% Vol.)	11.76	11.76	11.77	11.86
Molecular Weight	28.51	28.46	28.40	28.34
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	64,720	62,637	60,847	57,736
CT Stack				
CT - Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,760,570	2,702,850	2,651,790	2,578,530
Temperature (°F)	1,168	1,182	1,193	1,200
Molecular weight	28.51	28.46	28.40	28.34
Volume flow (acfm)- calculated	1,917,380	1,897,213	1,877,244	1,837,032
(ft3/s)- calculated	31,956	31,620	31,287	30,617
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,168	1,182	1,193	1,200
CT volume flow (acfm)	1,917,380	1,897,213	1,877,244	1,837,032
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	84.1	83.2	82.3	80.5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000

Table A-22. Maximum Emissions for Criteria Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	17	17	17	17
Emission rate (lb/hr)- provided	17.0	17.0	17.0	17.0
(TPY)	4.3	4.3	4.3	4.3
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)				
Fuel Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel use (lb/hr)	64,720	62,637	60,847	57,736
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	64.7	62.6	60.8	57.7
(TPY)	16.18	15.66	15.21	14.43
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	9.29	9.77	10.17	10.6
Oxygen (%)	11.76	11.76	11.77	11.86
Turbine Flow (acfm)	1,917,380	1,897,213	1,877,244	1,837,032
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
Emission rate (lb/hr)	228.2	220.8	214.1	203.3
(TPY)	57.1	55.2	53.5	50.8
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	35	35	35	35
Moisture (%)	9.29	9.77	10.17	10.6
Turbine Flow (acfm)	1,917,380	1,897,213	1,877,244	1,837,032
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
Emission rate (lb/hr)	86.1	84.0	82.2	79.7
(TPY)	21.5	21.0	20.5	19.9
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Turbine Flow (acfm)	1,917,380	1,897,213	1,877,244	1,837,032
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
Emission rate (lb/hr)	5.42	5.32	5.23	5.09
(TPY)	1.4	1.3	1.3	1.3
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0136	0.0132	0.0128	0.0122
(TPY)	0.0034	0.0033	0.0032	0.0030

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-23. Maximum Emissions for Other Regulated PSD Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1.26E+03	1.22E+03	1.19E+03	1.19E+03
Emission Rate (lb/hr)	4.79E-07	4.64E-07	4.51E-07	4.51E-07
(TPY)	1.20E-07	1.16E-07	1.13E-07	1.13E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.331	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	4.18E-04	4.04E-04	3.93E-04	3.93E-04
(TPY)	1.04E-04	1.01E-04	9.81E-05	9.81E-05
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	32.54	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	4.10E-02	3.97E-02	3.86E-02	3.86E-02
(TPY)	1.03E-02	9.93E-03	9.65E-03	9.65E-03
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (c) , lb/10^{12} Btu	2.11E+02	2.11E+02	2.11E+02	2.11E+02
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	2.66E-01	2.58E-01	2.51E-01	2.51E-01
(TPY)	6.66E-02	6.45E-02	6.26E-02	6.26E-02
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	7.90E-04	7.64E-04	7.42E-04	7.42E-04
(TPY)	1.97E-04	1.91E-04	1.86E-04	1.86E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	64,720	62,637	60,847	57,736
Sulfur (lb/hr)	32.36	31.32	30.42	28.87
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	5	5	5	5
Emission Rate (lb/hr)	4.96	4.80	4.66	4.42
(TPY)	1.24	1.20	1.16	1.11

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA, 1981; (c) 4 ppm assumed based on ASTM D2880
(d) assumed based on combustion estimates from GE.

Table A-24. Maximum Emissions for Hazardous Air Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	9.98E-03	9.66E-03	9.38E-03	9.38E-03
(TPY)	2.49E-03	2.41E-03	2.35E-03	2.35E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.1	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	1.39E-03	1.34E-03	1.30E-03	1.30E-03
(TPY)	3.47E-04	3.36E-04	3.26E-04	3.26E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	4.09E-03	3.96E-03	3.84E-03	3.84E-03
(TPY)	1.02E-03	9.89E-04	9.61E-04	9.61E-04
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	6.76	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	8.53E-03	8.25E-03	8.02E-03	8.02E-03
(TPY)	2.13E-03	2.06E-03	2.00E-03	2.00E-03
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	2	2	2	2
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	2.52E-03	2.44E-03	2.37E-03	2.37E-03
(TPY)	6.31E-04	6.10E-04	5.93E-04	5.93E-04
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	37	37	37	37
Heat Input Rate (MMBtu/hr)	1.26E+03	1.22E+03	1.19E+03	1.19E+03
Emission Rate (lb/hr)	4.67E-02	4.52E-02	4.39E-02	4.39E-02
(TPY)	1.17E-02	1.13E-02	1.10E-02	1.10E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	432	432	432	432
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	5.45E-01	5.27E-01	5.12E-01	5.12E-01
(TPY)	1.36E-01	1.32E-01	1.28E-01	1.28E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	1.09E-01	1.05E-01	1.02E-01	1.02E-01
(TPY)	2.72E-02	2.63E-02	2.56E-02	2.56E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	0.37842	0.3662406	0.3557784	0.3557784
(TPY)	0.094605	0.09156015	0.0889446	0.0889446
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	23	23	23	23
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	2.90E-02	2.81E-02	2.73E-02	2.73E-02
(TPY)	7.25E-03	7.02E-03	6.82E-03	6.82E-03
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	237	237	237	237
Heat Input Rate (MMBtu/hr)	1,261	1,221	1,186	1,186
Emission Rate (lb/hr)	2.99E-01	2.89E-01	2.81E-01	2.81E-01
(TPY)	7.47E-02	7.23E-02	7.03E-02	7.03E-02

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-25. Design Information and Stack Parameters for Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Ambient Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	190.3	182.44	174.64	165.54
Net heat rate (Btu/kWh, LHV)	9,080	9,210	9,330	9,482
(Btu/kWh, HHV)	10,079	10,223	10,356	10,525
Heat input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
(MMBtu/hr, HHV)	1,918	1,865	1,809	1,742
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with margin of 11%	4,121,430	3,949,380	3,860,580	3,725,160
- provided	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Moisture (% Vol.)	7.74	8.84	9.61	10.73
Oxygen (% Vol.)	12.39	12.15	12.01	11.81
Molecular Weight	28.48	28.36	28.27	28.15
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	82,933	80,648	78,205	75,335
CT Stack				
CT- Stack height (ft)	60	60	60	60
Diameter (ft)	22	22	22	22
Turbine Flow Conditions (CT Stack-Unit 4 only)				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	4,121,430	3,949,380	3,860,580	3,725,160
Temperature (°F)	1,109	1,130	1,145	1,158
Molecular weight	28.48	28.36	28.27	28.15
Volume flow (acfm)- calculated	2,762,391	2,693,812	2,666,222	2,604,882
(ft3/s)- calculated	46,040	44,897	44,437	43,415
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	1,109	1,130	1,145	1,158
CT volume flow (acfm)	2,762,391	2,693,812	2,666,222	2,604,882
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	121.1	118.1	116.9	114.2

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: GE, 2000.

Table A-26. Maximum Emissions for Criteria Pollutants for FPL Sanford Repowering Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Ambient Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	10	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0	10.0
(TPY)	2.5	2.5	2.5	2.5
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,851,839	1,800,825	1,746,274	1,682,185
Sulfur content (grains/ 100 cf)	1	1	1	1
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	5.3	5.1	5.0	4.8
(TPY)	1.32	1.29	1.25	1.20
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	15	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Oxygen (%)	12.39	12.15	12.01	11.81
Turbine Flow (acfm)	2,762,391	2,693,812	2,666,222	2,604,882
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
Emission rate (lb/hr)	116.7	112.4	109.9	106.0
(TPY)	29.2	28.1	27.5	26.5
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	12	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Turbine Flow (acfm)	2,762,391	2,693,812	2,666,222	2,604,882
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
Emission rate (lb/hr)	44.9	53.3	51.8	49.6
(TPY)	11.2	13.3	13.0	12.4
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	1.5	1.5	1.5	1.5
Moisture (%)	7.74	8.84	9.61	10.73
Turbine Flow (acfm)	2,762,391	2,693,812	2,666,222	2,604,882
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
Emission rate (lb/hr)	3.20	3.05	2.96	2.84
(TPY)	0.8	0.8	0.7	0.7
Lead (lb/hr)= NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2000; Golder Associates, 2000; EPA, 1996

Table A-27. Maximum Emissions for Other Regulated PSD Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Ambient Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1.92E+03	1.87E+03	1.81E+03	1.74E+03
Emission Rate (lb/hr)	2.30E-09	2.24E-09	2.17E-09	2.09E-09
(TPY)	5.75E-10	5.60E-10	5.43E-10	5.23E-10
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	1.43E-06	1.40E-06	1.35E-06	1.30E-06
(TPY)	3.59E-07	3.49E-07	3.38E-07	3.26E-07
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	1,851,839	1,800,825	1,746,274	1,682,185
Sulfur (lb/hr)	2.65	2.57	2.49	2.40
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	5	5	5	5
Emission Rate (lb/hr)	0.41	0.39	0.38	0.37
(TPY)	0.10	0.10	0.10	0.09

Sources: (a) Golder Associates, 2000; (b) EPA, 1981; (c) Assumed.

Note: No Emission Factors for Hydrogen chloride (HCl) from natural gas firing.

Table A-28. Maximum Emissions for Hazardous Air Pollutants for FPL Martin Simple Cycle CT Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Ambient Inlet Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	500	500	500	500
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	1.53E-03	1.49E-03	1.45E-03	1.39E-03
(TPY)	3.84E-04	3.73E-04	3.62E-04	3.48E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	34	34	34	34
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	6.52E-02	6.34E-02	6.15E-02	5.92E-02
(TPY)	1.63E-02	1.59E-02	1.54E-02	1.48E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1.92E+03	1.87E+03	1.81E+03	1.74E+03
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (b) , lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	0	0	0	0
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	0	0	0	0
(TPY)	0	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis (a) , lb/10^{12} Btu	10	10	10	10
Heat Input Rate (MMBtu/hr)	1,918	1,865	1,809	1,742
Emission Rate (lb/hr)	1.92E-02	1.87E-02	1.81E-02	1.74E-02
(TPY)	4.79E-03	4.66E-03	4.52E-03	4.36E-03

Sources: (a) Golder Associates, 2000; (b) EPA,1996 (AP-42,Table 3.1-4)

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY FOR THE PROPOSED COMBUSTION TURBINES

B.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS regulations (40 CFR, Subpart GG) applicable to gas turbines 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 Frame 7F turbines proposed for the project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm). The NSPS NO_x emission limit adjustment is not affected by natural gas combustion.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

B.2.1 NITROGEN OXIDES

Advanced dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is technically feasible for the proposed project. Available information suggests that "hot" SCR with dry low-NO_x combustor technology or with wet injection is also available.

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 B-2 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 obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina.

Historically, the most stringent NO_x controls for CTs established as LAER/BACT by state agencies were 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. However, advanced dry low-NO_x technology has only recently been developed and made available for gas turbines. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process.

SCR has been installed or permitted in over 100 projects. The majority of these projects (more than 90 percent) were initially cogeneration facilities with capacities of 50 MW or less. Most of these projects have been in California. Many of these projects have installed SCR 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:

> 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.

As discussed in Section 3.0, BACT involves an evaluation of the economic, environmental, and energy impacts of alternative control technologies. In contrast, LAER only considers the technical aspects of control.

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

There are also projects with SCR located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are also cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with a majority 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 of NO_x in the exhaust gas stream. The most common emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, a few facilities have reported emission limits of 3.5 ppm and less.

Wet injection historically (pre-1990's) has been the primary method of reducing NO_x emissions from CTs. Indeed, 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, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 15 ppmvd (corrected to 15 percent O_2) or less when firing natural gas.

Technology Description and Feasibility

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 results (i.e., CO and VOC emissions). In "F" Class turbines using wet injection with gas firing, the NO_x emission rates in the 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbine. Wet injection is the only current feasible means of reducing NO_x emissions in the combustion process when firing oil.

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 conventional machines manufactured by Westinghouse, GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Westinghouse and GE have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. 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 when firing natural gas at baseload conditions is 9 ppmvd (corrected to 15 percent O_2), a level which is guaranteed by the selected vendor for the project.

Selective Catalytic Reduction

Selective Catalytic Reduction (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. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR with base metal catalysts. 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 primarily limited to combined-cycle facilities that burn natural gas with small amounts of fuel oil, since SCR catalysts are contaminated by sulfur-containing fuels . For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience with SCR has not been extensive, certain cost, technical, and environmental considerations have surfaced for units firing both natural gas and oil while using SCR.

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 with concomitant cost and technical requirements. 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.

Zeolite and specially designed high temperature catalysts, which are reported to be capable of withstanding temperature ranges up to 1,100°F, have become 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 1,100°F and above, the high-temperature catalyst will be irreparably damaged.

In the 1990s there are four simple cycle combustion turbine projects that have installed SCR with operating experience. These projects are:

- Redding Municipal Power – 3 GE Frame 5 CTs fired with natural gas. The CTs are operated as a peaking facility.
- SoCal Gas Company – 4 Solar Centaur CTs (4MW equivalent each) fired with natural gas. The CTs are operated in intermediate cycling duty.
- UnoCal Brea Research Center – a single 4 MW CT firing natural gas. The CT operates in intermediate to base load duty.
- Puerto Rico Electric Power Authority (Cambalache Facility) – 3 ABB Type 11 N (83 MW each) firing No. 2 distillate oil.

The SCRs for all these CTs were designed to operate at temperatures less than 1,000 °F. Many of the smaller CTs have exhaust temperatures less than 1,000 °F. The Cambalache Facility had a once through steam generator in the ductwork leading to SCR used for power augmentation that reduced the catalyst temperature to less than 1,000 °F. Experience on these systems has shown significant catalyst deactivation occurs with peaking and intermediate cycling duty while firing natural gas. Under these conditions catalyst deactivation has occurred after operating from 350 to 4,000 hours. For intermediate-base load duty and firing natural gas, catalyst deactivation improved but still occurred after 8,000 hour of operation and well less the catalyst guarantee. When firing distillate oil, catalyst deactivation occurred after 600 hours. Due to the problems with oil firing, the SCR system for the Cambalache Facility has been removed. This experience suggests that SCR for simple cycle CTs while available from vendors has not been demonstrated as feasible.

$SCONO_x$™ Process

$SCONO_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc.

The $SCONO_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The $SCONO_x$™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (1)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (2)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (3)$$

CO_2 produced by reaction (1) and (2) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (3), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The $SCONO_x$™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\,H_2 + CO_2 \rightarrow K_2CO_3 + 4\,H_2O_{(g)}) + N_2 \quad (4)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the $SCONO_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being re-generated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONO$_x$™ system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture is then passed across a low temperature shift catalyst, forming CO_2 and additional hydrogen. The resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:

$$CH_4 + \frac{1}{2} O_2 + 1.88\, N_2 \Rightarrow CO + 2\, H_2 + 1.88\, N_2 \qquad (5)$$

$$CO + 2\, H_2 + H_2O + 1.88\, N2_2 \Rightarrow CO_2 + 3\, H_2 + 1.88\, N_2 \qquad (6)$$

The SCONO$_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For SCONO$_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONO$_x$™ catalyst that reforms the natural gas.

The SCONO$_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system ($SCONO_x$™) to remove sulfur compounds is installed upstream of the $SCONO_x$™ catalyst. During regeneration of the $SCONO_x$™ catalyst, either hydrogen sulfide or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the $SCONO_x$™ process is proprietary. $SCONO_x$™ oxidation/absorption and regeneration reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \tag{7}$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \tag{8}$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \tag{9}$$

$$[SO_3 + \text{SORBER}] + 4\,H_2 \rightarrow H_2S + 3\,H_2O \tag{10}$$

Utility materials needed for the operation of the $SCONO_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the $SCONO_x$™ control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine (30 MW size) equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The $SCONO_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

The $SCONO_x$™ control technology is not considered to be technically feasible because it has not been commercially demonstrated on large CTs. The CTs planned for the project, Westinghouse 501 F units, each have a nominal generating capacity of 170 MW which are approximately six times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the $SCONO_x$™ technology given the large differences in machine flow rates are unknown. Additional concerns with the $SCONO_x$™ control technology include process complexity (multiple catalytic oxidation / absorption / regeneration systems), reliance on only one supplier, and the relatively brief (approximately 18 months) operating history of the technology.

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:

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \Rightarrow 2N_2 + CO_2 + 2H_2O$$

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 and 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 501F 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.

Thermal $DeNO_x$

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_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, 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 501 F combustion turbine is typically 1,100°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.

Technology Demonstration and Feasibility

The technical evaluation of post-combustion gas controls that include NO_xOUT, Thermal DeNO_x, NSCR, and SCONO™ indicate that these processes have not been applied to simple-cycle turbines and are technically infeasible for the project because of process constraints (e.g., temperature). While high-temperature SCR is feasible, it has not been demonstrated on simple-cycle "F" class turbines in peaking service. Wet injection cannot achieve emission rates lower than 25 ppm when firing natural gas in an "F" Class machine and is not offered by the preferred vendor.

For the BACT analysis, dry low-NO_x combustion technology is technically feasible when firing natural gas and SCR in combination with combustion controls is a potentially feasible alternative that can achieve a maximum degree of emission reduction. The advanced dry low-NO_x combustor alone can achieve 9 ppm (corrected) and the SCR with dry low-NO_x combustor is capable of achieving a NO_x emission level of 3.6 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions).

Below is a summary of the technical demonstration and feasibility for the proposed project.

Technology	Simple Cycle
Dry Low-NO_x Combustors	Demonstrated and Feasible – Gas Firing
Wet Injection	Not Feasible/Available – Gas Firing
Wet Injection	Feasible/Available – Oil Firing
Selective Catalytic Reduction	Not Demonstrated on "F" Class turbines in peaking service
Thermal De NO_x	Not Feasible
NO_x Out	Not Feasible
SCO NO_x	Not Feasible
NSCR	Not Feasible

SCR Cost Estimates

Tables B-3 and B-4 present the total capital and annualized cost for SCR applied to simple cycle operation, respectively. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993). Vendor based estimates were used for the SCR system. Standard EPA recommended cost factors were used. A capital recovery period of 15 years was used for the capital costs and 3 years for the reoccurring capital costs (i.e., catalyst). SCR system in simple-cycle operation would be subjected to temperatures exceeding 1,000°F where considerable wear can take place resulting in lower life of equipment. Capital recovery periods in this case may be much lower.

B.2.2 Carbon Monoxide

Identification of CO Control Technologies

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 B-5 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. 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 CTs being evaluated, CO emissions will not exceed 12 ppmvd, corrected to 15 percent O_2, dry conditions when firing natural gas under full load conditions.

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).

Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required.

For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas. Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, during simple-cycle operation, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

Oxidation Catalyst Costs

Tables B-6 and B-7 present the capital and annualized cost for an oxidation catalyst applied to simple cycle operation. The maximum CO impacts are less than 0.1 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as reducing acidic deposition, to reducing CO.

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

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

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 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 B-2. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emission Limit	Control Method	Efficiency (%)	Type
WYANDOTTE ENERGY	MI	Feb-99	TURBINE, COMBINED CYCLE, POWER PLANT	500 MW	4.5 PPM	SCR	70	BACT
MOBILE ENERGY LLC	AL	Jan-99	TURBINE, GAS, COMBINEO CYCLE	168 MW	0.019 LB/MMBTU	SCR & DLN COMBUSTORS DURING GAS FIRING. STEAM/WATER INJECTION DURING OIL FIRING	0	BACT-PSD
COLORADO SPRINGS UTILITIES	CO	Jan-99	TURBINE, COMBINE, NATURAL GAS FIREO	30 MW EACH	15 PPMVD ABOVE 70% LOA	POLLUTION PREVENTION BUILT INTO EOUIPMENT.	0	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	GA	Dec-98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160 MW EA	15 PPMVD @ 15% O2	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF NAT. GAS.	0	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	GA	Dec-98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160 MW EA	42 PPMVD @ 15% O2	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF FUEL OIL.	0	BACT-PSD
SANTA ROSA ENERGY LLC	FL	Dec-98	TURBINE, COMBUSTION, NATURAL GAS	241 MW	9.8 PPM@15%O2 DB ON	ORY LOW NOX BURNER	0	BACT-PSD
CITY OF LOMPOC (PORTABLE TUBGRINDER IC ENGINE)	CA	Dec-98	IC ENGINE, DIESEL-FIRED, PORTABLE 460 BHP, CATERPI	460 BHP	580 PPMVD @ 15% O2	OIRECT INJECTION, TURBOCHARGEO, INTAKE INTERCOOLER	0	BACT-OTHER
LSP - COTTAGE GROVE, L.P.	MN	Nov-98	ENGINE, OIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	1.85 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	0	BACT-PSO
LSP - COTTAGE GROVE, L.P.	MN	Nov-98	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1988 MMBTU/H (CTG)	4.5 PPMDV @15%O2 (NG)	SELECTIVE CATALYTIC REDUCTION (SCR) WITH A NOX CEM ANO PEM.	0	BACT-PSO
WESTERN GAS RESOURCES - HILIGHT GAS PLANT	WY	Oct-98	ENGINES, COMPRESSOR, 2 EA	1650 HP	1 G/HP-H	3 - WAY CATALYST SYSTEM AND AIR/FUEL RATIO CONTRO-LLER.	0	BACT-PSD
SABA PETROLEUM, INC. (BELL COMPRESSOR PLANT)	CA	Oct-98	IC ENGINE, COMPRESSOR, NATURAL GAS-FIRED	747 BHP	0.15 G/B-HP-H	3-WAY CATALYTIC CONVERTER. MFGR: DCLI, INC; MODEL:DC67/77-10 WITH ELECTRONIC AIR/FUEL RATIO CONTROLLER	0	BACT-OTHER
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	ME	Sep-98	TURBINE, COMBINEO CYCLE, NATURAL GAS	175 MW	9 PPMVD @15% O2 GAS	DRY LOW NOX BURNER-1 OPTION IS CONSIOERED FOR OIL ANO IS SELECTED.	0	BACT-OTHER
TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	NM	Aug-98	GAS TURBINES	375 MMBTU/H	15 PPM	WATER INJECTION FOLLOWED BY SELECTIVE CATALYTIC REDUCTION	85	BAC7-PSD
CASCO RAY ENERGY CO	ME	Jul-98	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	3.5 PPM @15% O2	SELECTIVE CATALYTIC REDUCTION	0	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	FL	Jul-98	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO	2174 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX BURNERS FOR SIMPLE CYCLE, SCR WHEN COMBINED CYCLE	0	BACT-PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	CO	Jun-98	SIMPLE CYCLE TURBINE, NATURAL GAS	1122 MM BTU/HR	25 PPM @ 15% O2	DRY LOW NOX COMBUSTION	0	BACT-PSD
BRIDGEPORT ENERGY, LLC	CT	Jun-98	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260 MW/HRSG PER TURBINE	6 PPM NAT. GAS	ORY LOW NOX BURNER WITH SCR	60	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	ENGINE, COMPRESSOR, 9 EA	3200 HP	0.5 G/HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	ENGINES, COMPRESSOR, 2 EA	1200 HP	0.9 G/B-HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	ENGINES, COMPRESSOR, 9 EA	3200 HP	0.9 G/B-HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY.	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	COMPRESSOR, ENGINES, 2 EA	1200 HP	0.9 G/HP-H	ULTRA LOW NOX LEAN BURNTECHNOLOGY.	0	BACT-PSD
RUMFORD POWER ASSOCIATES	ME	May-98	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	1906 MMBTU/H	3.5 PPM @ 15% O2	SCR AMMONIA INJECTION SYSTEM AND CATALYTIC REACTORTO REOUCE NOX.	85	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	Mar-98	GAS TURBINES, COGEN, W/DUCT BURNERS	675 MMBTU/H TURBINE	6 PPM @ 15% O2 NG	LOW NOX BURNERS. LOW NOX COMBUSTORS. SCR OURING GAS FIRING ONLY.	85	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	Mar-98	GAS TURBINES, COGEN, W/DUCT BURNERS	675 MMBTU/H TURBINE	42 PPM @ 15% O2 NG OIL	LOW NOX COMBUSTORS, LOW NOX BURNERS, WATER INJECTION DURING OIL FIRING.	85	BACT-PSD
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	2/27/98	TURBINE, STATIONARY	33.3 MW	25 PPM @ 15% O2	DRY LOW NOX BURNERS	40	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	LA	2/13/98	TURBINE GAS, GE, 7ME 7	988 MMBTU/H	9 PPMV	DRY LOW NOX TO LIMIT NOX EMISSION TO 9PPMV	0	BACT-PSD
MILLENNIUM POWER PARTNER, LP	MA	2/2/98	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534 MMBTU/H	0.013 LB/MMBTU	DRY LOW-NOX COMBUSTION TECHNOLOGY IN CONJUNCTION WITH SCR ADD-ON NOX CONTROLS.	0	BACT-PSD
MINNESOTA METHANE TAJIUAS CORPORATION	CA	1/9/98	EQUIPMENT, LANDFILL GAS TO ENERGY PRODUCTION	43.68 MMBTU/H	0.59 G/B-HP-H	LEAN BURN, EXHAUST ROUTED THROUGH AFTERBURNER TO FURTHER COMBUST ENGINE CO AND UNBURNED HYDROCARBONS	0	BACT
BASF CORPORATION	LA	12/30/97	TURBINE, COGEN UNIT 2, GE FRAME 6	42.4 MW	6 PPMV NAT. GAS	STEAM INJECTION AND SCR TO LIMIT NOX TO 8 PPM FOR NATURAL GAS AND 25 PPM FOR WASTE GAS (80% H2)	0	BACT-PSD
ARCHIE CRIPPEN	CA	12/9/97	IC ENGINE, DETROIT DIESEL MODEL 8V-92TA	500 BHP	6.2 G/B-HP-H	NO CONTROL	0	BACT
WILLIAMS FIELD SERVICES—MIDDLE MESA CDP	NM	12/3/97	NATURAL GAS COMPRESSOR STATION, 14 ENGINES	1478 HP, EACH	4.51 LB/HR EACH ENGINE	CLEAN/LEAN BURN COMBUSTION	0	BACT-PSD
SOUTHERN NATURAL GAS	AL	Mar-98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9,160 HP	53 LB/HR		0	BACT-PSD
SOUTHERN NATURAL GAS	AL	Mar-98	9160 HP GE MODEL MS3002G NATURAL GAS FIRED TURBINE	9,160 HP	53 LB/HR		0	BACT-PSD
ALABAMA POWER COMPANY	AL	Dec-97	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100 MW	15 PPM	DRY LOW NOX BURNERS	0	BACT-PSD
BUCKNELL UNIVERSITY	PA	Nov-97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0 MW	25 PPMV@15%O2	SOLONOX BURNER; LOW NOX BURNER	0	BACT-OTHER
NORTHERN CALIFORNIA POWER AGENCY	CA	Oct-97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	25 PPMVD @ 15% O2	ORY LOW NOX BURNERS	0	LAER
LORDSBURG L.P.	NM	Jun-97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	74.4 LBS/HR	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCHEDULED COMBUSTION.	60	BACT-PSD
SOUTHERN CALIFORNIA GAS COMPANY	CA	May-97	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR	0	LAER
MEAD COATED BOARD, INC.	AL	Mar-97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	25 PPMVD@ 15% O2 (GAS)	FUEL OIL SULFUR CONTENT <=0.05% BY WEIGHT, DRY LOW NOX COMBUSTOR DESIGN FIRING GAS AND DRY LOW NOX COMBUSTOR WITH WATER INJECTION FIRING OIL	0	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT .	LA	Mar-97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRUCTION.	0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	Feb-97	COMBUSTION TURBINE, NATURAL GAS	100 MW	0 SEE FACILITY NOTES	DRY LOW NDX COMBUSTIDN	0	BACT-PSD
CALRESOURCES LLC	CA	Jan-97	SOLAR MODEL 1100 SATURN GAS TURBINE	14 MMBTU/HR	89 PPMVD @15% O2	NO CONTROL	0	LAER
TEMPO PLASTICS	CA	Dec-96	GAS TURBINE COGENERATION UNIT	0.0	0.109 LB/MMBTU	LOW-NDX CDMBUSTOR	0	LAER
SOUTHERN NATURAL GAS COMPANY	MS	Dec-96	TURBINE, NATURAL GAS-FIRED	9,160 HORSEPOWER	110 PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION	0	BACT-PSD
SOUTHERN NATURAL GAS COMPANY-SELMA CDMPRESSOR STAT	AL	Dec-96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE	0.0	53 LB/HR		0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	Nov-96	COMBUSTION TURBINE, NATURAL GAS	100 MW	15 PPM; SEE FAC. NOTES	DRY LOW NOX COMBUSTION	0	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	60 LB/HR (GAS)	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	72	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	73 LB/HR (OIL)	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	72	BACT-PSD
BLUE MOUNTAIN POWER, LP	PA	Jul-96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	4 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING OIL. OIL FIRING LIMITS SET TO 8.4 PPM @15% O2	84	LAER
CITY OF ST.PAUL POWER PLANT	AK	Jun-96	INTERNAL COMBUSTION	3.4 MW	427 TPY	AFTERCOOLERS	0	BACT-PSD
CITY OF UNALASKA	AK	Jun-96	INTERNAL COMBUSTION	8.5 MW	633 TPY	LIMIT OF OPERATION HOURS AND AFTERCOOLERS	0	BACT-PSD
GENERAL ELECTRIC GAS TURBINES	SC	Apr-96	I.C. TURBINE	2,700 MMBTU/HR	885 LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMISSIONS	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1,908 MMBTU/HR	512 LB/HR (OIL)	WATER INJECTION; FUEL SPEC: 0.04% N FUEL OIL	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1908 MMBTU/HR	158 LB/HR (GAS)	WATER INJECTION	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), FUEL OIL	116 MW	20 PPMVD	WATER INJECTION WITH SCR	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	9 PPMVD	DRY LOW NDX BURNER WITH SCR	0	BACT-PSD
GEORGIA GULF CORPORATION	LA	Mar-96	GENERATOR, NATURAL GAS FIRED TURBINE	1,123 MM BTU/HR	25 PPMV-CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION	0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FL	Jan-96	COMBINED CYCLE COMBUSTION TURBINE	140 MW	15 PPM @ 15% O2	DRY LNB STAGED COMBUSTION	0	BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	Sep-95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	75 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
UNION CARBIDE CORPORATION	LA	Sep-95	GENERATOR, GAS TURBINE	1,313 MM BTU/HR	25 PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	Jul-95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	35 LB/HR AS NO2	STEAM INJECTION PLUS SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM. USE OF NO. 2 FUEL OIL WITHNITROGEN CONTENT NOT TO EXCEED 0.10% BY WEIGHT.	0	BACT-PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	MO	Jul-95	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49 MW	42 PPM BY VOL 1 HR AVG (	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	0	BACT-PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	MO	Jul-95	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49 MW	75 PPM BY VOL 1 HR AVG (	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	0	BACT-PSD

Table B-2. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions

BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	Jun-95	TURBINE, NATURAL GAS FIRED	240 MW	3.5 PPM @ 15% O2	SCR	0	LAER
PANDA-KATHLEEN, L.P.	FL	Jun-95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	15 PPM @ 15% O2	DRY LOW NOX BURNER	0	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	PA	May-95	TURBINE, NATURAL GAS	580 MMBTU/HR	55 PPM @ 15% O2	STEAM INJECTION	75	RACT
MILAGRO, WILLIAMS FIELD SERVICE	NM	May-95	TURBINE/COGEN, NATURAL GAS (2)	800 MMCF/DAY	9 PPM @ 15% O2	DRY LOW NOX (GENERAL ELECTRIC MODEL PG6541B)	94	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	Apr-95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	15 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS	0	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	Apr-95	OIL FIRED COMBUSTION TURBINE	74 MW	42 PPM AT 15% OXYGEN	WATER INJECTION	0	BACT-PSD
LEDERLE LABORATORIES	NY	Apr-95	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	42 PPM, 18 LB/HR	STEAM INJECTION	0	BACT-PSD
PILGRIM ENERGY CENTER	NY	Apr-95	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1,400 MMBTU/HR	4.5 PPM, 23.6 LB/HR	STEAM INJECTION FOLLOWED BY SCR	0	BACT
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD	Mar-95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	91	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	Mar-95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL	0	LAER
LSP-COTTAGE GROVE, L.P.	MN	Mar-95	COMBUSTION TURBINE/GENERATOR	1,970 MMBTU/HR	4.5 PPM @ 15% O2 GAS	SELECTIVE CATALYTIC REDUCTION (SCR)	70	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	Feb-95	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89 MW	360 TPY	WATER INJECTION.	0	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	Jan-95	TURBINES, NATURAL GAS (2)	5,500 HP	7.4 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DRY/LOW NOX	66	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	NY	Dec-94	SIEMENS V84.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	25 PPM	WATER INJECTION	70	BACT
INDECK-OSWEGO ENERGY CENTER	NY	Oct-94	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	42 PPM, 75.00 LB/HR	STEAM INJECTION	53	BACT
FULTON COGEN PLANT	NY	Sep-94	GE LM5000 GAS TURBINE	500 MMBTU/HR	36 PPM, 65 LB/HR	WATER INJECTION	59	BACT
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520 MMBTU/H	25 PPMDV @ 15% O2 (GAS)	WATER INJECTION	30	BACT-PSD
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520 MMBTU/H	62 PPMDV @ 15% O2 (OIL)	WATER INJECTION	30	BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	Jul-94	TURBINE	350 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX BURNER	74	BACT-PSD
COLORADO POWER PARTNERSHIP	CO	Jul-94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	42 PPM @ 15% O2	WATER INJECTION	66	BACT-PSD
MUDDY RIVER L.P.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	303 LB/HR	LOW NOX BURNER	0	BACT-PSD
CSW NEVADA, INC.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	273 LB/HR	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	May-94	TURBINES, NATURAL GAS (2)	1,720 MMBTU	4.5 PPM @ 15% O2	SCR	82	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU/HR	25 PPM BY VOL 1 HR AVG (	LOW NOX BURNERS, AND WATER INJECTION	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1,345 MMBTU/HR	1,135 TPY (NO. 2 OIL)	LOW NOX BURNERS, AND WATER INJECTION	0	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	May-94	TURBINE, COMBUSTION, NATURAL GAS	80 MW	25 PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS	0	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	May-94	GAS TURBINES	75 MW (TOTAL POWER)	200 TPY	INTERNAL COMBUSTION CONTROLS	0	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	Apr-94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	21 LB/HR	SCR WITH LOW NOX COMBUSTORS	47	BACT-OTHER
HERMISTON GENERATING CO.	OR	Apr-94	TURBINES, NATURAL GAS (2)	1,696 MMBTU	4.5 PPM @ 15% O2	SCR	82	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, NATURAL GAS (2)	1,510 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, FUEL OIL (2)	1,730 MMBTU/H	42 PPMVD @ 15 %O2	WATER INJECTION	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, SYNGAS (COAL GASIFICATION)	1,755 MMBTU/H	25 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, FUEL OIL	1,765 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	0	BACT-PSD
INTERNATIONAL PAPER	LA	Feb-94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	25 PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL	0	BACT
KAMINE/BESICORP CARTHAGE L.P.	NY	Jan-94	GE FRAME 6 GAS TURBINE	491 BTU/HR	42 PPM, 76.6 LB/HR	STEAM INJECTION	63	BACT
ORANGE COGENERATION LP	FL	Dec-93	TURBINE, NATURAL GAS, 2	368 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	Dec-93	GE LM-5000 GAS TURBINE	550 MMBTU/HR	25 PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC; NATURAL GAS ONLY	80	BACT
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	Oct-93	TURBINE, GAS-FIRED	11,257 HP	42 PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY	66	BACT-PSD
FLORIDA GAS TRANSMISSION	FL	Sep-93	TURBINE, GAS	132 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	VA	Sep-93	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	10.2 X109 SCF/YR NAT GAS	131 LB/HR(GAS); 339 OIL	DRY LOW NOX COMBUSTOR; DESIGN, WATER INJECTION	0	BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	Aug-93	TURBINE, NATURAL GAS	12,600 BHP	0.58 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION	71	BACT-PSD
LOCKPORT COGEN FACILITY	NY	Jul-93	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	424 MMBTU/HR	42 PPM	STEAM INJECTION	78	BACT
ANITEC COGEN PLANT	NY	Jul-93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	25 PPM, 41 LB/HR	NO CONTROLS	0	BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	640 MMBTU/H (EACH)	16 PPMDV	SCR	0	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	6.3 PPMDV	SCR	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, OIL	1,650 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, GAS	1,615 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
INDECK ENERGY COMPANY	NY	May-93	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	32 PPM	STEAM INJECTION	58	BACT
PHOENIX POWER PARTNERS	CO	May-93	TURBINE (NATURAL GAS)	311 MMBTU/HR	22 PPM @ 15% O2	DRY LOW NOX COMBUSTION	0	BACT-OTHER
TRIGEN MITCHEL FIELD	NY	Apr-93	GE FRAME 6 GAS TURBINE	425 MMBTU/HR	80 PPM, 90 LB/HR	STEAM INJECTION	20	BACT
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	928 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	371 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	869 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	367 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSO
EAST KENTUCKY POWER COOPERATIVE	KY	Mar-93	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1,492 MMBTU/H (EACH)	42 PPM @ 15% O2 (OIL)	WATER INJECTION	48	SEE NOTES
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	Jan-93	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	0.08 LB/MMBTU (GAS)	LOW NOX BURNERS (ON THE DUCT BURNER) STEAM INJECTION INTO THE TURBINE	0	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	OK	Dec-92	TURBINE, COMBUSTION	58 MW	65 PPM @ 15% O2 (OIL)	COMBUSTION CONTROLS	83	BACT-OTHER
OKLAHOMA MUNICIPAL POWER AUTHORITY	OK	Dec-92	TURBINE, COMBUSTION	58 MW	25 PPM @ 15% O2 (GAS)	COMBUSTION CONTROLS	83	BACT-OTHER
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE, OIL	1,170 MMBTU/H	42 PPMVD @ 15 % 02	STEAM INJECTION	0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE,GAS	1,214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	Nov-92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133 MMBTU/HR (EACH)	4.5 PPM	SCR AND DRY LOW NOX	0	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	Nov-92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9 PPM (GAS)	DRY LOW NOX OR SCR	0	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	Nov-92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	55 PPM (OIL)	DRY LOW NOX OR SCR	0	BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	Nov-92	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR	0	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	Nov-92	TURBINE (NATURAL GAS & OIL)	1,150 MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	0	BACT-OTHER
GOAL LINE, LP ICEFLOE	CA	Nov-92	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386 MMBTU/HR	5 PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT.	88	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	15 PPM	SCR	61	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS (TOTAL)	0.0	89.7 TPY	SCR	0	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	9 PPM	SELECTIVE CATALYTIC REDUCTION (SCR)	75	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	7.4 X10(7) GPY FUEL OIL	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR)	80	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF]	1.4 X10(9) BTU/H #2 OIL	66 LBS/HR/UNIT	WATER INJECTION AND SCR	80	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	1,331 X10(7) SCF/Y NAT GAS	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR) W/ WATER INJEC	80	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF]	1.5 X10(9) BTU/HR N GAS	9 PPMDV/UNIT @ 15% 02	SCR WITH WATER INJECTION	80	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	Sep-92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	88.6 TPY (EACH TURBINE)	LOW NOX COMBUSTOR	0	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	Sep-92	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	42 PPM, 78.6 LB/HR	WATER INJECTION	50	BACT
NORTHERN STATES POWER COMPANY	SD	Sep-92	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	24 PPM @ 15% O2 GAS	WATER INJECTION FOR GAS & DISTILLATION	0	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	Sep-92	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)*	9 PPM (GAS)	DRY LOW NOX	0	BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	Sep-92	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)*	42 PPM (OIL)	WATER INJECTOR	0	BACT-OTHER
WEPCU, PARIS SITE	WI	Aug-92	TURBINES, COMBUSTION (4)	0.0	65 PPM @ 15% O2 (OIL)	GOOD COMBUSTION PRACTICES	0	BACT-PSD
WEPCU, PARIS SITE	WI	Aug-92	TURBINES, COMBUSTION (4)	0.0	25 PPM @ 15% O2 (GAS)	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,029 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,866 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	0	BACT-PSD
NORTHWEST PIPELINE COMPANY	WA	Aug-92	TURBINE, GAS-FIRED	12,100 HP	198 PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/95)	78	BACT-PSD
CNG TRANSMISSION	OH	Aug-92	TURBINE (NATURAL GAS) (3)	5,500 HP (EACH)	1.6 G/HP-HR*	LOW NOX COMBUSTION	0	BACT-OTHER
SARANAC ENERGY COMPANY	NY	Jul-92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123 MMBTU/HR (EACH)	9 PPM	SCR	0	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, OIL FIRED (2 EACH)	1,840 M BTU/HR	25 PPMVD, FUEL N AFLOW	MAXIMUM WATER INJECTION	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	HI	Jul-92	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	42.3 LB/HR	WATER INJECTION	69	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, GAS FIRED (2 EACH)	1,617 M BTU/HR	25 PPM @ 15% O2	MAXIMUM WATER INJECTION	0	BACT-PSD

Table B-2. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions

INDECK-YERKES ENERGY SERVICES	NY	Jun-92	GE FRAME 6 GAS TURBINE (EP #00001)	432 MMBTU/HR	42 PPM, 74 LB/HR	STEAM INJECTION	35	BACT
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINES (2) (252 MW)	1,173 MMBTU/HR (EACH)	9 PPM GAS	STEAM INJECTION AND SCR	0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINE (79 MW)	1,173 MMBTU/HR	25 PPM GAS	STEAM INJECTION	0	BACT-OTHER
NORTHWEST PIPELINE CORPORATION	CO	May-92	TURBINE, SOLAR TAURUS	45 MMBTU/HR	96 PPMVD (UNTIL 11/98)	DRY LOW NOX COMBUSTOR (BY 11/01/98)	0	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	Apr-92	TURBINE, GAS AND DUCT BURNER	1,360 MMBTU/H EACH	9 PPM @ 15% O2, GAS	SCR	0	BACT-PSD
KENTUCKY UTILITIES COMPANY	KY	Mar-92	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1,500 MM BTU/HR (EACH)	42 PPM @ 15% O2, N. GAS	WATER INJECTION	0	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,175 MMBTU/H NAT. GAS	9 PPM @ 15% O2	SCR, STEAM INJECTION	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,117 MMBTU/H NO2 FUEL OIL	15 PPM @ 15% O2	SCR, STEAM INJ.	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION, 2	0.0	191 T/YR/UNIT		0	BACT-PSD
THERMO INDUSTRIES, LTD.	CO	Feb-92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% D2	DRY LOW NOX TECH.	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	42.3 LB/HR	COMBUSTOR WATER INJECTOR, WATER INJECTION	70	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 6	1,032 MMBTU/H, NAT GAS	25 PPM @ 15% O2	MAX WATER INJECTION	0	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 6	972 MMBTU/H, #2 OIL	0 SEE NOTES	MAX WATER INJECTION	0	BACT-PSD
LINDEN COGENERATION TECHNOLOGY	NJ	Jan-92	TURBINE, NATURAL GAS FIRED	50 X E12 BTU/YR	33.8 LB/HR	STEAM INJECTION AND SCR	95	BACT-PSD
ALYESKA PIPELINE SERVICE COMPANY	AK	Jan-92	SOLAR CENTAUR, 3	800 KW	150 PPMVD @ 15% O2	LOW NOX BURNERS	0	NSPS
KAMINE/BESICORP NATURAL DAM LP	NY	Dec-91	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	42 PPM, 80.1 LB/HR	STEAM INJECTION	35	BACT
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,247 MM BTU/HR	287 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION	0	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,313 MM BTU/HR	119 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD.	HI	Dec-91	TURBINE, FUEL OIL #2	28 MW	42 PPM	WATER INJECTION	71	BACT-PSD
KALAMAZOO POWER LIMITED	MI	Dec-91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1,806 MMBTU/H	15 PPMV	DRY LOW NOX TURBINES	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, OIL, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, GAS, 2 EACH	42 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
SHELL PIPELINE CORPORATION	CA	Nov-91	GENERATOR, EMERGENCY, PROPANE FIRED	82 BHP	0.28 LB/H	3-WAY CATALYTIC CONVERTER	60	BACT-PSD
DE LA GUERRA POWER, INC	CA	Nov-91	ENGINE IC & GEN (1 OF 3)	380 HP	6.34 LB/D	NON-SELECTIVE CATALYTIC CONVERTER	90	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, GAS, 4 EACH	35 MW	42 PPM @ 15% O2	WET INJECTION	70	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, OIL, 4 EACH	35 MW	65 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	Oct-91	TURBINE, GAS FIRED, SOLAR MODEL H	5,500 HP	6 PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	93	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	64.9 PPM @ 15% O2	LEAN BURN	0	NSPS
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	65.1 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	0	NSPS
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
FLORIDA POWER GENERATION	FL	Oct-91	TURBINE, OIL, 6 EACH	93 MW	42 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000 HP	225 PPM @ 15% O2	LEAN BURN	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	80	BACT-PSD
NUGGET OIL CO.	CA	Oct-91	GENERATOR, STEAM, GAS FIRED	63 MMBTU/H	0.043 LB/MMBTU	LOW NOX BURNER AND FLUE GAS RECIRCULATION*	57	BACT-PSD
CAROLINA POWER AND LIGHT CO.	SC	Sep-91	TURBINE, I.C.	80 MW	292 LB/H	WATER INJECTION	50	BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	Aug-91	TURBINE, GAS, 2	39 MMBTU/H	40 PPM @ 15% O2	H2O INJECT 0.67 LB/LB	71	BACT-PSD
ALGONQUIN GAS TRANSMISSION CO.	RI	Jul-91	TURBINE, GAS, 2	49 MMBTU/H	100 PPM @ 15% O2	LOW NOX COMBUSTION	0	BACT-OTHER
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, OIL, 1 EACH	80 MW	42 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
SUMAS ENERGY INC.	WA	Jun-91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	SCR	90	BACT-PSD
SAGUARO POWER COMPANY	NV	Jun-91	COMBUSTION TURBINE GENERATOR	35 MW	16.9 PPH (WINTER)	SELECTIVE CATALYTIC REDUCTION (SCR)	80	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, OIL, 2 EACH	400 MW	65 PPM @ 15% O2	LOW NOX COMBUSTORS	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, GAS, 4 EACH	400 MW	25 PPM @ 15% O2	LOW NOX COMBUSTORS	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, CG, 4 EACH	400 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	0	BACT-PSD
GRANITE ROAD LIMITED	CA	May-91	TURBINE, GAS, ELECTRIC GENERATION	461 MMBTU/H*	3.5 PPMVD @ 15% O2	SCR, STEAM INJECTION	97	BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	May-91	TURBINES, GAS, 2	35 KW EACH	25 PPM @ 15% O2	STEAM INJECTION/+SCR IN 1997	65	OTHER
CIMARRON CHEMICAL	CO	Mar-91	TURBINE #1, GE FRAME 6	33 MW	25 PPM @ 15% O2	WATER INJECTION	0	OTHER
CIMARRON CHEMICAL	CO	Mar-91	TURBINE #2, GE FRAME 6	33 MW	9 PPM @ 15% O2	SCR	0	OTHER
SEMINOLE FERTILIZER CORPORATION	FL	Mar-91	TURBINE, GAS	28 MW	9 PPM @ 15% O2	SCR	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, GAS, 4 EACH	240 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, OIL, 4 EACH	0.0	65 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	752 MMBTU/HR	42 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	752 MMBTU/HR	65 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	585 MMBTU/HR.	42 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	585 MMBTU/HR.	65 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	81.3 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	81.3 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	0	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ	Nov-90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.033 LB/MMBTU	STEAM INJECTION AND SCR	94	BACT-PSD
NORTHERN NATURAL GAS COMPANY	IA	Sep-90	ENGINE, COMPRESSOR	4,000 HP	1.6 G/B-HP-H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
NORTHERN NATURAL GAS COMPANY	IA	Sep-90	ENGINES, COMPRESSOR, 2	2,000 HP EACH	1.6 G/B-HP-H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TBG COGEN COGENERATION PLANT	NY	Aug-90	GE LM2500 GAS TURBINE	215 MMBTU/HR	75 PPM + FBN CORRECTIO	WATER INJECTION	80	BACT
PEPCO - CHALK POINT PLANT	MD	Jun-90	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	77 PPM @ 15% O2	DRY PREMIX AND WATER INJECTION	0	BACT-PSD
PEPCO - CHALK POINT PLANT	MD	Jun-90	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	0	BACT-PSD
PACIFIC GAS TRANSMISSION COMPANY	OR	Jun-90	TURBINE GAS, COMPRESSOR STATION	110 MMBTU/HR	199 PPM @ 15% O2	LOW NOX BURNER DESIGN	30	NSPS
PEPCO - STATION A	MD	May-90	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	NJ	Feb-90	TURBINE, NATURAL GAS FIREO	1,000 MMBTU/HR	0.044 LB/MMBTU	STEAM INJECTION AND SCR	93	BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	Dec-89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	306 LBS/HR	WATER INJECTION	0	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	Nov-89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	0	BACT-OTHER
PACIFIC GAS TRANSMITION	OR	Nov-89	TURBINE, NAT. GAS	14,600 HP	42 PPM @ 15% O2	LOW NOX BURNERS	75	BACT-PSD
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	MO	Oct-89	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION	0	BACT-PSD
KINGSBURG ENERGY SYSTEMS	CA	Sep-89	TURBINE, NATURAL GAS FIRED, DUCT BURNER	35 MW	6 PPM @ 15% O2	SCR, STEAM INJECTION	90	BACT-PSD
MEGAN-RACINE ASSOCIATES, INC	NY	Aug-89	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	42 PPMDV @ 15% O2	WATER INJECTION	80	BACT

Note: PSD= Prevention of Significant Deterioration
BACT= Best Available Control Technology
LAER= Lowest Achievable Emission Rate

Table B-3. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$2,835,000	Vendor Estimate
Ammonia Storage Tank	$136,500	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758	Vatavauk, 1990
Instrumentation	$50,000	Additional NO_x Monitor and System
Taxes	$170,100	6% of SCR Associated Equipment and Catalyst
Freight	$141,750	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,400,108	
Direct Installation Costs		
Foundation and supports	$272,009	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$476,015	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$136,004	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$68,002	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$34,001	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$34,001	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,040,032	
Total Capital Costs (TCC)	$4,440,140	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$444,014	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$222,007	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$444,014	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$88,803	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$44,401	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$133,204	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,426,444	
Total Direct, Indirect and Capital Costs (TDICC)	$5,866,584	Sum of TCC and TInCC

Table B-4. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	\$18,720	24 hours/week at \$15/hr
Supervision	\$2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	\$55,220	\$300 per ton for Aqueous NH_3
PSM/RMP Update	\$15,000	Engineering Estimate
Inventory Cost	\$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	\$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	\$19,690	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$676,028	
Energy Costs		
Electrical	\$37,968	80kW/h for SCR & 200kW/h for cooling @ \$0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	\$207,224	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	\$245,192	
Indirect Annual Costs		
Overhead	\$46,049	60% of Operating/Supervision Labor and Ammonia
Property Taxes	\$58,666	1% of Total Capital Costs
Insurance	\$58,666	1% of Total Capital Costs
Annualized Total Direct Capital	\$644,151	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	\$807,531	
Total Annualized Costs	\$1,728,751	Sum of TDAC, TEC and TIAC
Cost Effectiveness	\$13,636	NO_x Reduction Only
	\$25,214	Net Emission Reduction

Table B-5. Summary of Best Available Control Technology (BACT) Determinations for Carbon Monoxide (CO) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	CO Emission Limit	Control Method	Efficiency (%)	Type
PDC EL PASO MILFORD LLC	CT	Apr-99	TURBINE, COMBUSTION, ABB GT-24E,#2 WITH 2 CHILLERS	1.97 MMCF/H	13 LB/H NAT GAS	OXIDATION CATALYST	0	BACT-PSD
PDC EL PASO MILFORD LLC	CT	Apr-99	TURBINE, COMBUSTION, ABB GT-24, #1 WITH 2 CHILLERS	1.97 MMCF/H	13 LB/H NAT GAS	OXIDATION CATALYST	0	BACT-PSD
ALABAMA POWER COMPANY - THEODORE COGENERATION	AL	Mar-99	TURBINE, WITH DUCT BURNER	170 MW	0.066 LB/MMBTU	EFFICIENT COMBUSTION	0	BACT-PSD
MOBILE ENERGY LLC	AL	Jan-99	TURBINE, GAS, COMBINED CYCLE	168 MW	0.04 LB/MMBTU	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TENASKA GEORGIA PARTNERS, L.P.	GA	Dec-98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160 MW EA	15 PPMVD @ 15% O2	USING 15% EXCESS AIR. CO EMISSION IS BECAUSE OFNATURAL GAS.	0	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	GA	Dec-98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160 MW EA	33 PPMVD	CO EMISSION IS BECAUSE OF FUEL OIL. WHEN OUTPUT ISBELOW 123 MW LIMIT IS 33 PPMVD AND ABOVE 123 MW LIMIT IS 20 PPMVD.	0	BACT-PSD
WESTBROOK POWER LLC	ME	Dec-98	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	15 PPM @15% O2	USING 15 % EXCESS AIR.	0	BACT-PSD
SANTA ROSA ENERGY LLC	FL	Dec-98	TURBINE, COMBUSTION, NATURAL GAS	241 MW	0	DRY LOW NOX BURNER GOOD COMBUSTION PRACTICE	0	BACT-PSD
GORHAM ENERGY LIMITEO PARTNERSHIP	ME	Dec-98	TURBINE, COMBINED CYCLE	900 MW TOTAL	5 PPM @ 15% O2 (NAT G)	0.05% SULFUR DISTILLATE OIL #2 IS USED. EMISSION IS FROM EACH 300 MW SYSTEM.	0	BACT-PSD
WESTERN GAS RESOURCES - HILIGHT GAS PLANT	WY	Oct-98	ENGINES, COMPRESSOR, 2 EA	1650 HP	2 G/HP-H	3 - WAY CATALYST SYSTEM AND AIR/FUEL RATIO CONTRO-LLER.	0	BACT-PSD
WILLIAMS FIELD SERVICES	NM	Sep-98	IC ENGINE, COMPRESSOR	27240 HP	2.65 G/B-HP-H	LEAN-BURN ENGINE DESIGN	0	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	ME	Sep-98	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	9 PPMVD @15% O2 GAS		0	BACT-OTHER
TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	NM	Aug-98	GAS TURBINES	375 MMBTU/H	18 PPM	GOOD COMBUSTION PRACTICES	0	BACT-PSD
WILLIAMS FIELD SERVICES CO.	NM	Jul-98	RECIPROCATING ENGINE, NAT. GAS	1375 HP	2.65 G/B-HP-H	CLEAN BURN COMBUSTION TECHNOLOGY	0	BACT-PSD
CASCO RAY ENERGY CO	ME	Jul-98	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	20 PPM @ 15% O2	15% EXCESS AIR	0	BACT-PSD
CITY OF LAKELANO ELECTRIC AND WATER UTILITIES	FL	Jul-98	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO	2174 MMBTU/H	25 PPM	GOOD COMBUSTION WITH DRY LOW NOX BURNERS OXIDATION CATALYST MAY BE USED	0	BACT-PSD
COLORAOO SPRINGS UTILITIES-NIXON POWER PLANT	CO	Jun-98	SIMPLE CYCLE TURBINE, NATURAL GAS	1122 MM BTU/HR	0.8 ORE	CATALYTIC OXIDATION	80	BACT-PSD
BRIDGEPORT ENERGY, LLC	CT	Jun-98	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260 MW/HRSG PER TURBINE	10 PPM GAS & OIL	PRE-MIX FUEL FAIR TO OPTIMIZE EFFICIENCY ACTUAL EMISSIONS EXPECTEO BETWEEN 5-7PPM	0	BACT-PSD
WILLIAMS FIELD SERVICES CO.	NM	Jun-98	RECIPROCATING ENGINES, NAT. GAS	21920 HP	2.65 G/B-HP-H	LEAN BURN ENGINE DESIGN	0	BACT-PSD
ENCOGEN HAWAII, L.P.	HI	Jun-98	TURBINES, COMBUSTION, 2 EA	23 MW	57.5 PPMVD @ 15% O2	GOOD COMBUSTION DESIGN AND OPERATION.	0	BACT-PSD
GENERAL ELECTRIC PLASTICS	AL	May-98	COMBINED CYCLE (TURBINE AND DUCT BURNER)	0	0.08 LBS/MMBTU	PROPER COMBUSTION	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	ENGINES, COMPRESSOR, 2 EA	1200 HP	2.8 G/B-HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY.	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	ENGINE, COMPRESSOR, 9 EA	3200 HP	0.5 G/HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY AND CATALYTIC CRACKING.	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	ENGINES, COMPRESSOR, 9 EA	3200 HP	0.5 G/B-HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY. CATALYTIC CONVERTER.	0	BACT-PSD
UNION PACIFIC RESOURCES - PATRICK DRAW GAS PLANT	WY	May-98	COMPRESSOR, ENGINES, 2 EA	1200 HP	2.8 G/HP-H	ULTRA LOW NOX LEAN BURN TECHNOLOGY.	0	BACT-PSD
RUMFORD POWER ASSOCIATES	ME	May-98	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	1906 MMBTU/H	15 PPM @ 15% O2	GE DRY LOW-NOX COMBUSTOR DESIGN. GOOD COMBUSTION CNTRL.	0	BACT-PSD
WILLIAMS FIELD SERVICES CO.	NM	Apr-98	NATURAL GAS RECIPROCATING ENGINE	1476 HP	2.65 G/B-HP-H	LEAN BURN DESIGN	0	BACT-PSD
WILLIAMS FIELD SERVICES CO.	NM	Apr-98	ENGINE, IC RECIPROCATING, NAT. GAS	1374 HP	2.65 G/B-HP-H	CLEAN BURN COMBUSTION TECHNOLOGY	0	BACT-PSD
ANOROSCOGGIN ENERGY LIMITED	ME	Mar-98	GAS TURBINES, COGEN, W/DUCT BURNERS	675 MMBTU/H TURBINE	74.21 LB/H NG	CATALYTIC OXIDATION, GOOD COMBUSTION PRACTICES.	0	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	Mar-98	GAS TURBINES, COGEN, W/DUCT BURNERS	675 MMBTU/H TURBINE	43.73 LB/H NG OIL	CATALYTIC OXIDATION, GOOD COMBUSTION PRACTICES.	0	BACT-PSD
TIVERTON POWER ASSOCIATES	RI	Feb-98	COMBUSTION TURBINE, NATURAL GAS	265 MW	12 PPM @ 15% O2	GOOD COMBUSTION	0	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	LA	Feb-98	TURBINE GAS, GE, 7ME 7	988 MMBTU/H	25 PPMV	GOOD EQUIPMENT DESIGN, PROPER COMBUSTION TECHNIOUEAND MIN. 2% EXCESS O2	0	BACT-PSD
MILLENNIUM POWER PARTNER, LP	MA	Feb-98	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534 MMBTU/H	0.07 LB/MMBTU	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTION WITH SCR ADD-ON NOX CONTROL.	0	BACT-PSD
MAUI ELECTRIC COMPANY	HI	Jan-98	TURBINE, COMBUSTION, 2 EA	20 MW	44 PPMVD @ 15% O2	GOOD COMBUSTION DESIGN AND OPERATION.	0	BACT-PSD
BASF CORPORATION	LA	Dec-97	TURBINE, COGEN UNIT 2, GE FRAME 6	42.4 MW	83.93 LB/MMBTU	GOOD DESIGN, PROPER COMBUSTION TECHNIQUES, 2% EXCESS O2	0	BACT-PSD
ARCHIE CRIPPEN	CA	Dec-97	IC ENGINE, OETROIT DIESEL MODEL 8V-92TA	500 BHP	0.51 G/B-HP-H	NO CONTROL	0	BACT
WILLIAMS FIELD SERVICES—MIDDLE MESA CDP	NM	Dec-97	NATURAL GAS COMPRESSOR STATION, 14 ENGINES	1478 HP, EACH	6 LB/HR EACH ENGINE	CLEAN/LEAN BURN TECHNOLOGY	0	BACT-PSD
BUCKNELL UNIVERSITY	PA	Nov-97	NG FIREO TURBINE, SOLAR TAURUS T-7300S	5 MW	50 PPMV@15%O2	GOOD COMBUSTION	0	BACT-OTHER
LORDSBURG L.P.	NM	Jun-97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	27 LBS/HR	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PRDPER AIR- FUEL RATIO.	0	BACT-PSD
MEAD COATED BOARD, INC.	AL	Mar-97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	28 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	0	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	Mar-97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	70 LB/HR	COMBUSTIDN DESIGN AND CONSTRUCTION.	0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	Feb-97	COMBUSTION TURBINE, NATURAL GAS	100 MW	0 SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES	0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	Nov-96	COMBUSTION TURBINE, NATURAL GAS	100 MW	0 SEE P2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	33 PPMDV	COMBUSTION CONTROLS.	0	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	100 PPMDV AT MIN. LOAO	COMBUSTION CONTROLS.	0	BACT-PSD
BLUE MOUNTAIN POWER, LP	PA	Jul-96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	3.1 PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRING NO. 2 OIL. AT 75% NG LIMIT SET TO 22.1 PPM	80	OTHER
COMMONWEALTH CHESAPEAKE CORPORATION	VA	May-96	3 COMBUSTION TURBINES (OIL-FIREO)	6,000 HRS/YR	98 TPY	GOOD COMBUSTION OPERATING PRACTICES	0	BACT/NSPS
PORTSIDE ENERGY CORP.	IN	May-96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	40 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 40 PPMVD AT 15% OXYGEN.	0	BACT-PSD
PORTSIDE ENERGY CORP.	IN	May-96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	12 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 PPMVD AT 15% OXYGEN.	0	BACT-PSD
GENERAL ELECTRIC GAS TURBINES	SC	Apr-96	I.C. TURBINE	2,700 MMBTU/HR	27.169 LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMISSIONS	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1,906 MMBTU/HR	81 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1,906 MMBTU/HR	60 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MS	Apr-96	COMBUSTION TURBINE, COMBINED CYCLE	1,299 MMBTU/HR NAT GAS	26.3 PPM @ 15% O2, GAS	GOOD COMBUSTION CONTROLS	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), FUEL OIL	116 MW	30 PPMVD	COMPLETE COMBUSTION	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION	0	BACT-PSD
GEORGIA GULF CORPORATION	LA	Mar-96	GENERATOR, NATURAL GAS FIRED TURBINE	1,123 MM BTU/HR	972 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FL	Jan-96	COMBINED CYCLE COMBUSTION TURBINE	140 MW	20 PPM (NAT. GAS)	DRY LNB GOOD COMBUSTION PRACTICES	0	BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	Sep-95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION	0	BACT-PSD
UNION CARBIDE CORPORATION	LA	Sep-95	GENERATOR, GAS TURBINE	1,313 MM BTU/HR	199 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE	0	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	Jul-95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	20 LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES.	0	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	Jul-95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	104 LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES.	0	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	Jun-95	TURBINE, NATURAL GAS FIRED	240 MW	4 PPM @ 15% O2		0	LAER
PANDA-KATHLEEN, L.P.	FL	Jun-95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	25 PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE CT IS SELECTED, THE ABB CT WAS LESS THAN SIGNIFICANT EMIS. INCR FOR CO	0	BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	May-95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	28 PPM @ 15% O2		0	BACT-PSD
LEDERLE LABORATORIES	NY	Apr-95	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	48 PPM, 12.6 LB/HR		0	BACT-OTHER
PILGRIM ENERGY CENTER	NY	Apr-95	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 0000182)	1,400 MMBTU/HR	10 PPM, 29.0 LB/HR		0	BACT-OTHER
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD	Mar-95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	Mar-95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	26 LB/HR	PROPER OPERATION	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	Feb-95	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89 MW	426 TPY	GOOD COMBUSTION CONTROL	0	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	Jan-95	TURBINES, NATURAL GAS (2)	5,500 HP	13 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.	66	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	NY	Dec-94	SIEMENS V84.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	9.5 PPM	NO CONTROLS	0	BACT-OTHER
INDECK-OSWEGO ENERGY CENTER	NY	Oct-94	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	10 PPM, 10.00 LB/HR	NO CONTROLS	0	BACT-OTHER
FULTON COGEN PLANT	NY	Sep-94	GE LM5000 GAS TURBINE	500 MMBTU/HR	107 PPM, 120 LB/HR	NO CONTROLS	0	BACT-OTHER
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520 MMBTU/H	702 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	0	BACT-PSD
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520 MMBTU/H	414 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	0	BACT-PSD
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	Jul-94	NATURAL GAS-FIRED COMPRESSOR ENGINE	520 HORSEPOWER	1.7 LBS/HR	GOOD COMBUSTION	0	BACT
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	Jul-94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	1.3 LBS/HR	GOOD COMBUSTION	0	BACT
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	Jul-94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	1.9 LBS/HR	GOOD COMBUSTION	0	BACT
COLORADO POWER PARTNERSHIP	CO	Jul-94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	22 PPM @ 15% O2		0	BACT-PSD
MUDDY RIVER L.P.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	77 LB/HR	FUEL SPEC: NATURAL GAS	0	BACT-PSD
CSW NEVADA, INC.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	83 LB/HR	FUEL SPEC: NATURAL GAS	0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	May-94	TURBINES, NATURAL GAS (2)	1,720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-PSD

Table B-5. Summary of Best Available Control Technology (BACT) Determinations for Carbon Monoxide (CO) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	CO Emission Limit	Control Method	Efficiency (%)	Type
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1,345 MMBTU/HR	120 TPY	NONE	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1,345 MMBTU/HR	1290 TPY	NONE	0	BACT-PSD
NAVY PUBLIC WORKS CENTER	VA	May-94	1 EMERGENCY GENERATOR	1,500 KW	14.4 TPY	RETARD TIMING 6 DEGREES	0	NSPS
WEST CAMPUS COGENERATION COMPANY	TX	May-94	GAS TURBINES	75 MW (TOTAL POWER)	300 TPY	INTERNAL COMBUSTION CONTROLS	0	BACT
HERMISTON GENERATING CO.	OR	Apr-94	TURBINES, NATURAL GAS (2)	1,696 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, NATURAL GAS (2)	1,510 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSO
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, FUEL OIL (2)	1,730 MMBTU/H	30 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, SYNGAS (COAL GASIFICATION)	1,755 MMBTU/H	25 PPMVD	GOOD COMBUSTION	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, FUEL OIL	1,765 MMBTU/H	40 PPMVD	GOOD COMBUSTION	0	BACT-PSD
INTERNATIONAL PAPER	LA	Feb-94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	166 LB/HR	COMBUSTION CONTROL	0	BACT
KAMINE/BESICORP CARTHAGE L.P.	NY	Jan-94	GE FRAME 6 GAS TURBINE	491 BTU/HR	10 PPM, 11 0 LB/HR	NO CONTROLS	0	BACT-OTHER
ORANGE COGENERATION LP	FL	Dec-93	TURBINE, NATURAL GAS, 2	368 MMBTU/H	30 PPMVD	GOOD COMBUSTION	0	BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	Dec-93	GE LM-5000 GAS TURBINE	550 MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS	0	BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	Oct-93	TURBINE, GAS-FIRED	11,257 HP	50 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	VA	Sep-93	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	10.2 X109 SCF/YR NAT GAS	26 LB/HR	GOOD COMBUSTION OPERATING PRACTICES	0	BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	Aug-93	TURBINE, NATURAL GAS	12,600 BHP	0.42 GM/HP HR	AIR-TO-FUEL RATIO CONTROL DRY COMBUSTION CONTROLS	0	BACT-PSD
LOCKPORT COGEN FACILITY	NY	Jul-93	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	424 MMBTU/HR	10 PPM	NO CONTROLS	0	BACT-OTHER
ANITEC COGEN PLANT	NY	Jul-93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	36 PPM, 33 LB/HR	BAFFLE CHAMBER	80	SEE NOTE #4
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	640 MMBTU/H (EACH)	2 6 PPMDV	OXIDATION CATALYST	0	OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	1 6 PPMDV	OXIDATION CATALYST	0	OTHER
PSI ENERGY, INC. WABASH RIVER STATION	IN	May-93	COMBINED CYCLE SYNGAS TURBINE	1,775 MMBTU/HR	15 LESS THAN PPM	OPERATION PRACTICES AND GOOD COMBUSTION, COMBINED CYCLE SYNGAS TURBINE	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, OIL	1,850 MMBTU/H	98.4 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, GAS	1,615 MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
INDECK ENERGY COMPANY	NY	May-93	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	40 PPM	NO CONTROLS	0	BACT-OTHER
TRIGEN MITCHEL FIELD	NY	Apr-93	GE FRAME 6 GAS TURBINE	425 MMBTU/HR	10 PPM, 10 0 LB/HR	NO CONTROLS	0	BACT-OTHER
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	928 MMBTU/H	65 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	371 MMBTU/H	76 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	869 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	367 MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE	KY	Mar-93	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1,492 MMBTU/H (EACH)	75 LBS/H (EACH)	PROPER COMBUSTION TECHNIQUES	0	BACT-OTHER
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	Jan-93	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	22 LB/HR	DESIGN	0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE, OIL	1,170 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE,GAS	1,214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	Nov-92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133 MMBTU/HR (EACH)	13 PPM	COMBUSTION CONTROLS	0	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	Nov-92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9.5 PPM	COMBUSTION CONTROLS	0	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	Nov-92	TURBINE (NATURAL GAS & OIL)	1,150 MMBTU	0.0055 LB/MMBTU (GAS)*	COMBUSTION	0	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	11 LBS/HR	GOOD COMBUSTION	0	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS (TOTAL)	0	48 TPY	GOOD COMBUSTION	0	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	11 LBS/HR	GOOD COMBUSTION	0	BACT-PSD
PHILADELPHIA SOUTHWEST WATER TREATMENT PLANT	PA	Oct-92	ENGINES (2) (NATURAL GAS)	443 KW (EACH)	0	LEAN BURN ENGINE	0	OTHER
PHILADELPHIA NORTHEAST WATER TREATMENT PLANT	PA	Oct-92	ENGINES (3) (NATURAL GAS)	443 KW (EACH)	0	LEAN BURN ENGINE	0	OTHER
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	7.44 X10(7) GPY FUEL OIL	250 TOTAL TPY	GOOD COMBUSTION PRACTICES	0	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF]	1.36 X10(9) BTU/H #2 OIL	66 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	0	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	1,331 X10(7) SCF/Y NAT GAS	250 TOTAL TPY	GOOD COMBUSTION PRACTICES	0	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF]	1.51 X10(9) BTU/HR N GAS	57 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	0	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	Sep-92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (6 UNITS 75 EACH)	153 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	0	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	Sep-92	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	9 PPM, 11.0 LB/HR	NO CONTROLS	0	BACT-OTHER
NORTHERN STATES POWER COMPANY	SD	Sep-92	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	50 PPM FOR GAS	GOOD COMBUSTION TECHNIQUES	0	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	Sep-92	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)*	8 5 PPM	COMBUSTION CONTROL	0	BACT-OTHER
WEPCU, PARIS SITE	WI	Aug-92	TURBINES, COMBUSTION (4)	0	25 LBS/HR (SEE NOTES)		0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,029 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,866 MMBTU/H	79 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
CNG TRANSMISSION	OH	Aug-92	TURBINE (NATURAL GAS) (3)	5,500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	0	OTHER
SARANAC ENERGY COMPANY	NY	Jul-92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123 MMBTU/HR (EACH)	3 PPM	OXIDATION CATALYST	0	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, OIL FIRED (2 EACH)	1,640 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	HI	Jul-92	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	27 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	0	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, GAS FIRED (2 EACH)	1,617 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	0	BACT-PSD
INDECK-YERKES ENERGY SERVICES	NY	Jun-92	GE FRAME 6 GAS TURBINE (EP #00001)	432 MMBTU/HR	10 PPM, 10 LB/HR	NO CONTROLS	0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINES (2) (252 MW)	1,173 MMBTU/HR (EACH)	10 PPM	COMBUSTION CONTROLS	0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINE (79 MW)	1,173 MMBTU/HR	25 PPM	COMBUSTION CONTROL	0	BACT-OTHER
TENASKA WASHINGTON PARTNERS, L.P.	WA	May-92	COGENERATION PLANT, COMBINED CYCLE	1.83 MMBTU/HR	20 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	Apr-92	TURBINE, GAS AND DUCT BURNER	1,360 MMBTU/H EACH	11 PPM @ 15% O2, GAS		0	BACT-PSD
KENTUCKY UTILITIES COMPANY	KY	Mar-92	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1,500 MM BTU/HR (EACH)	75 LB/HR (EACH)	COMBUSTION CONTROL	0	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,175 MMBTU/H NAT. GAS	62 LB/H/UNIT	FURNACE DESIGN	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,117 MMBTU/H NO2 FUEL OIL	62 LB/H/UNIT	FURNACE DESIGN	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION, 2	0	229 T/YR/UNIT		0	BACT-PSD
THERMO INDUSTRIES, LTD.	CO	Feb-92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	27 LB/HR @ 100% PEAKLD	COMBUSTION DESIGN	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	56 LB/H @ 75-<100% PKLD	COMBUSTION DESIGN	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	181 LB/H @ 50-<75% PKLD	COMBUSTION DESIGN	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	476 LB/H @ 25-<50% PKLD	COMBUSTION DESIGN	0	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 8	1,032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	0	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 8	972 MMBTU/H, #2 OIL	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	0	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NY	Dec-91	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	0.02 LB/MMBTU, 10 LB/HR	NO CONTROLS	0	BACT-OTHER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,247 MM BTU/HR	80 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,313 MM BTU/HR	59 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD.	HI	Dec-91	TURBINE, FUEL OIL #2	28 MW	0 SEE NOTES	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KALAMAZOO POWER LIMITED	MI	Dec-91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1,806 MMBTU/H	20 PPMV	DRY LOW NOX TURBINES	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, OIL, 2 EACH	42 MW	78 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, GAS, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, GAS, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, OIL, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	Oct-91	TURBINE, GAS-FIRED	48 MMBTU/H	7.74 PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	80	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	Oct-91	TURBINE, GAS FIRED, SOLAR MODEL H	5,500 HP	7.74 PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	80	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	0	BACT-PSD
FLORIDA POWER GENERATION	FL	Oct-91	TURBINE, OIL 6 EACH	93 MW	54 LB/H	COMBUSTION CONTROL	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000 HP	80 PPM @ 15% O2	LEAN BURN	0	BACT-PSD
CAROLINA POWER AND LIGHT CO.	SC	Sep-91	TURBINE, I.C.	80 MW	60 LB/H		0	BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	Aug-91	TURBINE, GAS, 2	39 MMBTU/H	80 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS	0	BACT-PSD
ALGONQUIN GAS TRANSMISSION CO.	RI	Jul-91	TURBINE, GAS, 2	49 MMBTU/H	0 114 LB/MMBTU	GOOD COMBUSTION PRACTICES	0	BACT-OTHER
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, OIL 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
SUMAS ENERGY INC.	WA	Jun-91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	CO CATALYST	80	BACT-PSD
SAGUARO POWER COMPANY	NV	Jun-91	COMBUSTION TURBINE GENERATOR	34.5 MW	9 PPH	CONVERTER (CATALYTIC)	90	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, OIL, 2 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	0	SACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, GAS, 4 EACH	400 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	0	SACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, CG, 4 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	0	SACT-PSD
NORTHERN CONSOLIDATED POWER	PA	May-91	TURBINES, GAS, 2	34 8 KW EACH	110 T/YR	OXIDATION CATALYST	90	OTHER

Table B-5 Summary of Best Available Control Technology (BACT) Determinations for Carbon Monoxide (CO) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	CO Emission Limit	Control Method	Efficiency (%)	Type
LAKEWOOD COGENERATION, L.P.	NJ	Apr-91	TURBINES (#2 FUEL OIL) (2)	1,190 MMBTU/HR (EACH)	0.08 LB/MMBTU	TURBINE DESIGN	0	BACT-OTHER
LAKEWOOD COGENERATION, L.P.	NJ	Apr-91	TURBINES (NATURAL GAS) (2)	1,190 MMBTU/HR (EACH)	0.028 LB/MMBTU	TURBINE DESIGN	0	BACT-OTHER
CIMARRON CHEMICAL	CO	Mar-91	TURBINE #2, GE FRAME 6	33 MW	250 T/YR, LESS THAN	CO CATALYST	0	OTHER
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, OIL, 4 EACH	0	33 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	40 LBS/HR	CATALYTIC CONVERTER	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	40 LBS/HR	CATALYTIC CONVERTER	0	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ	Nov-90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.0055 LB/MMBTU	CATALYTIC OXIDATION	80	BACT-PSD
TBG COGEN COGENERATION PLANT	NY	Aug-90	GE LM2500 GAS TURBINE	215 MMBTU/HR	0.181 LB/MMBTU	CATALYTIC OXIDIZER	80	BACT
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	Dec-89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	23 LBS/HR	GOOD COMBUSTION PRACTICES	0	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	Nov-89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC	NY	Aug-89	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	0.028 LB/MMBTU, 11 LB/HR	NO CONTROLS	0	BACT-OTHER
UNOCAL	CA	Jul-89	TURBINE, GAS (SEE NOTES)	0	10 PPM @ 15% O2	OXIDATION CATALYST	75	BACT-OTHER

Note: PSD= Prevention of Significant Deterioration
BACT= Best Available Control Technology
LAER= Lowest Achievable Emission Rate

Table B-6. Direct and Indirect Capital Costs for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$843,000	Vendor Quote
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$84,300	10% of SCR Associated Equipment
Sales Tax	$50,580	6% of SCR Associated Equipment/Catalyst
Freight	$42,150	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$1,086,788	
Direct Installation Costs		
Foundation and supports	$86,943	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$152,150	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$43,472	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$21,736	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,868	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,868	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$331,036	
Total Capital Costs	$1,417,824	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$141,782	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$70,891	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$141,782	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$28,356	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$14,178	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$42,535	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$439,526	
Total Direct, Indirect and Capital Costs (TDICC)	$1,857,350	Sum of TCC and TInCC

Table B-7. Annualized Cost for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$214,333	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$28,365	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,496	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$257,371	
Energy Costs		
Heat Rate Penalty	$82,890	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$82,890	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$18,574	1% of Total Capital Costs
Insurance	$18,574	1% of Total Capital Costs
Annualized Total Direct Capital	$203,937	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$245,390	
Total Annualized Costs	$585,650	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$7,918	Simple CycleCombustion Turbine
	$8,858	Net Emission Reduction

SCR Vendor
Budgetary Proposal
GE Frame 7FA
Simple Cycle

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

ENGELHARD CORPORATION
CAMET® CO OXIDATION SYSTEMS
NOxCAT SCR NOx ABATEMENT CATALYST SYSTEMS

Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **CAMET®** CO Oxidation Catalyst Modules;
- Engelhard **NOxCAT VNX™** (combined cycle) and **ZNX™** (simple cycle) SCR catalyst in modules;
- Internal support structures for catalyst modules (frame); includes all hardware and gaskets for catalyst module installation;
- Ambient Air injection cooling system components (simple cycle);
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: 28% Aqueous Ammonia
  - Pre-piped & wired (including all valves and fittings) — Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
    - Blowers (on/off/flow indicators) — Air/ammonia flow indicator and controller
    - System pressure indicators — Main power disconnect switch

Excluded from Scope of Supply:
Ammonia storage and pumping
Any internally insulated reactor ductwork to house catalysts
Any transitions to and from reactor
Structural support
Any monorails and hoists for handling modules
Any interconnecting field piping or wiring
Electrical grounding equipment
Utilities
Foundations
All Monitors
All other items not specifically listed in Scope of Supply

BUDGET PRICES: **See Performance Data**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Simple cycle - 9,000 hours of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life
Performance Guarantee:	Combined cycle – 3 yearrs of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

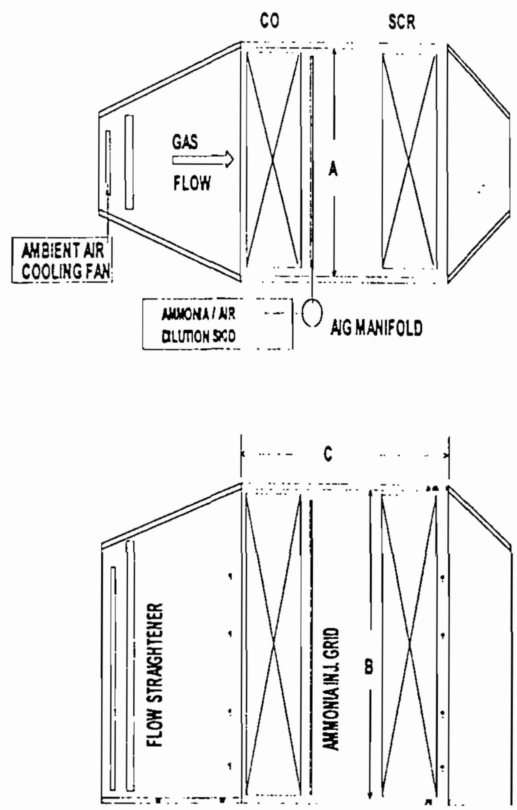
DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation - 10 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Operating manuals
Material Delivery 20 - 24 weeks after approval and release for fabrication

SYSTEM DESIGN BASIS:

Gas Flow from:	Westinghouse 501D and GE 7FA Combustion Turbines
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
CO Concentration (At catalyst face):	See Performance data
CO Reduction:	See Performance data
CO Pressure Drop:	See Performance data
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	See Performance data
NH3 Slip:	9 and 5 ppmvd@15%O_2
Pressure Drop through SCR	Nom. 4"WG

ENGELHARD

<u>Dimensions / Sketch:</u> Simple Cycle
CO and SCR - w/ ambient cooling
Required Cross Sectional Area
Inside Liner Width x Inside Liner Height
(A x B) sq. ft.
Reactor Depth (C) 15'-0"



ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Simple Cycle

ASSUMED AMBIENT	59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F	1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63
O2	12.61	11.04
CO2	3.63	5.20
H2O	7.60	11.20
Ar	0.93	0.93
AMBIENT AIR FLOW, lb/hr	332,949	348,316
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	4,232,949	4,428,316
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.70	72.37
O2	13.09	11.64
CO2	3.35	4.80
H2O	7.01	10.33
Ar	0.86	0.86
CALCULATED AIR + GAS MOL. WT.	28.48	28.32
GIVEN: TURBINE CO, ppmvd	9.0	20.0
CALC.: TURBINE CO, lb/hr	31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	9.0	42.0
CALC.: TURBINE NOx, lb/hr	64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE	7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE	8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025
DESIGN REQUIREMENTS		
CO CATALYST CO CONVERSION, %	90%	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12
SCR PRESSURE DROP, 4.0"WG – Nom.		
GUARANTEED PERFORMANCE DATA		
CO CONVERSION - % Min.	90.0%	90.0%
CO OUT, ppmvd @ 15% O2	0.7	1.4
CO OUT, lb/hr	3.2	7.2
CO PRESSURE DROP	2.2	2.4
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%
NOx OUT, lb/hr – Max.	25.1	138.1
NOx OUT, ppmvd@15%O2 – Max.	3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	139	424
NH3 SLIP, ppmvd@15%O2 – Max.	9	12
SCR PRESSURE DROP, "WG - Max.	4.2	4.4
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft	**1650.0**	
CO SYSTEM	**$843,000**	
REPLACEMENT CO CATALYST MODULES	**$643,000**	
SCR SYSTEM	**$2,835,000**	
REPLACEMENT SCR CATALYST MODULES	**$1,479,000**	

APPENDIX C

BUILDING DOWNWASH INFORMATION FROM BPIP

```
'BPIP data for FPL Martin New CTs 12/14/99,rev 12/27/99'
'ST'
'FEET' 0.3048
'UTMN'  0.
8
'CTSTRU1' 1 0.0
4     22
-262 -514
-298 -514
-298 -484
-262 -484
'CTSTRU2' 1 0.0
4     22
-262 -367
-298 -367
-298 -337
-262 -337
'CTSTRU3' 1 0.0
4     22
-262 -15
-298 -15
-298  15
-262  15
'CTSTRU4' 1 0.0
4     22
-262 132
-298 132
-298 162
-262 162
'AIRINL1' 1 0.0
4     55
-344 -523
-364 -523
-364 -475
-344 -475
'AIRINL2' 1 0.0
4     55
-344 -376
-364 -376
-364 -328
-344 -328
'AIRINL3' 1 0.0
4     55
-344 -24
-364 -24
-364  24
-344  24
'AIRINL4' 1 0.0
4     55
-344 123
-364 123
-364 171
-344 171
4
'CT1'   0.0   60.0  -233 -499
'CT2'   0.0   60.0  -233 -352
'CT3'   0.0   60.0  -233    0
'CT4'   0.0   60.0  -233  147
0
```

BPIP (Dated: 95086)

DATE : 12/27/99
TIME : 15:29:37
BPIP data for FPL Martin New CTs 12/14/99,rev 12/27/99

===========================
BPIP PROCESSING INFORMATION:
===========================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in FEET will be converted to meters using a conversion factor of 0.3048. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 0.00 degrees with respect to True North.

BPIP data for FPL Martin New CTs 12/14/99,rev 12/27/99

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
CT1	18.29	0.00	40.13	65.00
CT2	18.29	0.00	40.13	65.00
CT3	18.29	0.00	40.13	65.00
CT4	18.29	0.00	40.13	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 12/27/99
TIME : 15:29:37

BPIP data for FPL Martin New CTs 12/14/99,rev 12/27/99

BPIP output is in meters

SO BUILDHGT CT1	0.00	0.00	0.00	0.00	6.71	6.71
SO BUILDHGT CT1	16.76	16.76	16.76	16.76	16.76	6.71
SO BUILDHGT CT1	16.76	16.76	16.76	0.00	0.00	0.00
SO BUILDHGT CT1	0.00	0.00	0.00	0.00	6.71	6.71
SO BUILDHGT CT1	16.76	6.71	6.71	6.71	16.76	6.71
SO BUILDHGT CT1	6.71	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT1	0.00	0.00	0.00	0.00	14.06	13.41
SO BUILDWID CT1	15.58	15.47	14.63	15.47	15.58	13.41
SO BUILDWID CT1	15.13	14.07	12.59	0.00	0.00	0.00
SO BUILDWID CT1	0.00	0.00	0.00	0.00	14.06	13.41
SO BUILDWID CT1	15.58	10.91	9.14	10.91	15.58	13.41
SO BUILDWID CT1	14.06	0.00	0.00	0.00	0.00	0.00

SO BUILDHGT CT2	0.00	0.00	16.76	16.76	16.76	6.71
SO BUILDHGT CT2	16.76	16.76	16.76	16.76	16.76	6.71
SO BUILDHGT CT2	6.71	0.00	0.00	0.00	0.00	0.00
SO BUILDHGT CT2	0.00	0.00	0.00	0.00	6.71	6.71
SO BUILDHGT CT2	16.76	6.71	6.71	6.71	16.76	6.71
SO BUILDHGT CT2	6.71	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT2	0.00	0.00	12.59	14.07	15.13	13.41
SO BUILDWID CT2	15.58	15.47	14.63	15.47	15.58	13.41
SO BUILDWID CT2	14.06	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT2	0.00	0.00	0.00	0.00	14.06	13.41
SO BUILDWID CT2	15.58	10.91	9.14	10.91	15.58	13.41
SO BUILDWID CT2	14.06	0.00	0.00	0.00	0.00	0.00

SO BUILDHGT CT3	0.00	0.00	0.00	0.00	6.71	6.71
SO BUILDHGT CT3	16.76	16.76	16.76	16.76	16.76	6.71
SO BUILDHGT CT3	16.76	16.76	16.76	0.00	0.00	0.00
SO BUILDHGT CT3	0.00	0.00	0.00	0.00	6.71	6.71
SO BUILDHGT CT3	16.76	6.71	6.71	6.71	16.76	6.71
SO BUILDHGT CT3	6.71	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT3	0.00	0.00	0.00	0.00	14.06	13.41
SO BUILDWID CT3	15.58	15.47	14.63	15.47	15.58	13.41
SO BUILDWID CT3	15.13	14.07	12.59	0.00	0.00	0.00
SO BUILDWID CT3	0.00	0.00	0.00	0.00	14.06	13.41
SO BUILDWID CT3	15.58	10.91	9.14	10.91	15.58	13.41
SO BUILDWID CT3	14.06	0.00	0.00	0.00	0.00	0.00

SO BUILDHGT CT4	0.00	0.00	16.76	16.76	16.76	6.71
SO BUILDHGT CT4	16.76	16.76	16.76	16.76	16.76	6.71
SO BUILDHGT CT4	6.71	0.00	0.00	0.00	0.00	0.00
SO BUILDHGT CT4	0.00	0.00	0.00	0.00	6.71	6.71
SO BUILDHGT CT4	16.76	6.71	6.71	6.71	16.76	6.71
SO BUILDHGT CT4	6.71	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT4	0.00	0.00	12.59	14.07	15.13	13.41
SO BUILDWID CT4	15.58	15.47	14.63	15.47	15.58	13.41
SO BUILDWID CT4	14.06	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT4	0.00	0.00	0.00	0.00	14.06	13.41
SO BUILDWID CT4	15.58	10.91	9.14	10.91	15.58	13.41
SO BUILDWID CT4	14.06	0.00	0.00	0.00	0.00	0.00

APPENDIX D

DETAILED SUMMARY OF ISCST MODEL RESULTS

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :genoilc2.o87
ISCST3 OUTPUT FILE NUMBER 2 :genoilc2.o88
ISCST3 OUTPUT FILE NUMBER 3 :genoilc2.o89
ISCST3 OUTPUT FILE NUMBER 4 :genoilc2.o90
ISCST3 OUTPUT FILE NUMBER 5 :genoilc2.o91
First title for last output file is: 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS 2/7/00
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FUEL OIL

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BASE35					
Annual					
	1987	0.01222	300.	10000.	87123124
	1988	0.01148	300.	14000.	88123124
	1989	0.01309	300.	12000.	89123124
	1990	0.01315	300.	12000.	90123124
	1991	0.01334	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.16402	310.	18000.	87080724
	1988	0.17657	280.	20000.	88091724
	1989	0.16394	340.	20000.	89030624
	1990	0.18168	300.	18000.	90051524
	1991	0.16149	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.38573	350.	20000.	87011624
	1988	0.42984	280.	20000.	88091708
	1989	0.38237	250.	20000.	89011324
	1990	0.40985	140.	20000.	90121108
	1991	0.35711	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.68919	310.	20000.	87060503
	1988	0.68993	160.	20000.	88102603
	1989	0.67966	280.	20000.	89091103
	1990	0.78116	270.	20000.	90031003
	1991	0.80097	160.	20000.	91011803
HIGH 1-Hour					
	1987	1.81428	90.	1000.	87071513
	1988	1.10390	270.	5000.	88060313
	1989	1.07180	40.	5000.	89070311
	1990	1.64140	60.	2000.	90082313
	1991	1.64153	40.	700.	91071217
SOURCE GROUP ID: BASE59					
Annual					
	1987	0.01253	300.	10000.	87123124
	1988	0.01219	300.	12000.	88123124
	1989	0.01338	300.	12000.	89123124
	1990	0.01346	300.	12000.	90123124
	1991	0.01376	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.16695	310.	16000.	87080724
	1988	0.18029	280.	20000.	88091724
	1989	0.16754	340.	20000.	89030624
	1990	0.18509	300.	18000.	90051524
	1991	0.16496	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.39396	350.	20000.	87011624
	1988	0.43896	280.	20000.	88091708
	1989	0.39052	250.	20000.	89011324
	1990	0.41907	140.	20000.	90121108
	1991	0.36468	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.70351	310.	20000.	87060503
	1988	0.70372	160.	20000.	88102603
	1989	0.69281	280.	20000.	89091103
	1990	0.79629	270.	20000.	90031003
	1991	0.81811	160.	20000.	91011803
HIGH 1-Hour					
	1987	1.92480	90.	700.	87071513
	1988	1.11692	10.	5000.	88082111
	1989	1.07240	40.	5000.	89070311
	1990	1.64681	60.	2000.	90082313
	1991	1.73713	40.	700.	91071217
SOURCE GROUP ID: BASE95					

Annual					
	1987	0.01367	300.	10000.	87123124
	1988	0.01320	300.	12000.	88123124
	1989	0.01444	300.	10000.	89123124
	1990	0.01449	300.	12000.	90123124
	1991	0.01476	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.17629	310.	16000.	87080724
	1988	0.19179	280.	20000.	88091724
	1989	0.17890	340.	20000.	89030624
	1990	0.19583	300.	16000.	90051524
	1991	0.17564	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.41932	350.	20000.	87011624
	1988	0.46713	280.	20000.	88091708
	1989	0.41553	250.	20000.	89011324
	1990	0.44722	140.	20000.	90121108
	1991	0.38798	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.77200	90.	700.	87071515
	1988	0.74749	310.	20000.	88091003
	1989	0.73316	280.	20000.	89091103
	1990	0.84237	270.	20000.	90031003
	1991	0.87028	160.	20000.	91011803
HIGH 1-Hour					
	1987	2.31601	90.	700.	87071513
	1988	1.20080	280.	5000.	88082312
	1989	1.75943	200.	1500.	89070114
	1990	1.66303	60.	2000.	90082313
	1991	2.06790	40.	500.	91071217
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.01558	300.	10000.	87123124
	1988	0.01527	300.	10000.	88123124
	1989	0.01665	300.	10000.	89123124
	1990	0.01671	300.	10000.	90123124
	1991	0.01693	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.19475	310.	16000.	87080724
	1988	0.21439	280.	20000.	88091724
	1989	0.20058	340.	20000.	89030624
	1990	0.21740	300.	16000.	90051524
	1991	0.19657	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.46924	350.	20000.	87011624
	1988	0.52252	280.	20000.	88091708
	1989	0.46445	250.	20000.	89011324
	1990	0.50219	140.	20000.	90121108
	1991	0.43376	240.	20000.	91102808
HIGH 3-Hour					
	1987	1.03194	90.	700.	87071515
	1988	0.83614	310.	20000.	88091003
	1989	0.81380	280.	18000.	89091103
	1990	0.93239	270.	18000.	90031003
	1991	0.97142	160.	20000.	91011803
HIGH 1-Hour					
	1987	3.09582	90.	700.	87071513
	1988	1.95584	200.	1500.	88032713
	1989	1.80257	200.	1500.	89070114
	1990	2.07749	320.	1500.	90082412
	1991	2.77753	40.	500.	91071217
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.01790	300.	10000.	87123124
	1988	0.01752	300.	10000.	88123124
	1989	0.01948	300.	10000.	89123124
	1990	0.01916	300.	10000.	90123124
	1991	0.01971	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.25722	310.	12000.	87080724
	1988	0.25426	280.	18000.	88091724
	1989	0.22500	340.	20000.	89030624
	1990	0.24230	300.	14000.	90051524
	1991	0.22009	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.52849	90.	500.	87071516
	1988	0.58455	280.	20000.	88091708

	1989	0.51439	250.	20000.	89011324
	1990	0.56479	140.	20000.	90121108
	1991	0.55914	40.	300.	91071224
HIGH 3-Hour					
	1987	1.40931	90.	500.	87071515
	1988	0.93541	310.	20000.	88091003
	1989	0.90521	280.	16000.	89091103
	1990	1.03586	270.	18000.	90031003
	1991	1.27720	40.	500.	91071218
HIGH 1-Hour					
	1987	4.22794	90.	500.	87071513
	1988	1.99945	200.	1500.	88032713
	1989	1.86336	200.	1500.	89070114
	1990	2.39435	140.	1500.	90072212
	1991	3.83160	40.	500.	91071217
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01630	300.	10000.	87123124
	1988	0.01602	300.	10000.	88123124
	1989	0.01777	300.	10000.	89123124
	1990	0.01752	300.	10000.	90123124
	1991	0.01803	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.20221	310.	14000.	87080724
	1988	0.22340	280.	20000.	88091724
	1989	0.20931	340.	20000.	89030624
	1990	0.22599	300.	16000.	90051524
	1991	0.20499	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.48938	350.	20000.	87011624
	1988	0.54457	280.	20000.	88091708
	1989	0.48414	250.	20000.	89011324
	1990	0.52482	140.	20000.	90121108
	1991	0.45447	40.	500.	91071224
HIGH 3-Hour					
	1987	1.15778	90.	700.	87071515
	1988	0.87139	310.	20000.	88091003
	1989	0.84637	280.	18000.	89091103
	1990	0.96964	270.	18000.	90031003
	1991	1.04325	40.	500.	91071218
HIGH 1-Hour					
	1987	3.47335	90.	700.	87071513
	1988	1.97005	200.	1500.	88032713
	1989	1.82284	200.	1500.	89070114
	1990	2.09232	320.	1500.	90082412
	1991	3.12975	40.	500.	91071217
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.01852	300.	10000.	87123124
	1988	0.01836	300.	10000.	88123124
	1989	0.02015	300.	10000.	89123124
	1990	0.01990	300.	10000.	90123124
	1991	0.02049	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.26369	310.	12000.	87080724
	1988	0.26196	280.	18000.	88091724
	1989	0.23218	340.	20000.	89030624
	1990	0.24990	300.	14000.	90051524
	1991	0.23100	40.	300.	91071224
HIGH 8-Hour					
	1987	0.59523	90.	500.	87071516
	1988	0.60266	280.	20000.	88091708
	1989	0.50696	250.	20000.	89011324
	1990	0.58354	140.	20000.	90121108
	1991	0.67231	40.	300.	91071224
HIGH 3-Hour					
	1987	1.58727	90.	500.	87071515
	1988	0.96435	310.	20000.	88091003
	1989	0.93325	280.	16000.	89091103
	1990	1.06629	270.	16000.	90031003
	1991	1.52271	40.	300.	91071218
HIGH 1-Hour					
	1987	4.76182	90.	500.	87071513
	1988	2.01389	200.	1500.	88032713
	1989	1.88265	200.	1500.	89070114
	1990	2.40648	140.	1500.	90072212
	1991	4.56814	40.	300.	91071217

SOURCE GROUP ID: LD5059

Annual					
	1987	0.01864	300.	10000.	87123124
	1988	0.01847	300.	10000.	88123124
	1989	0.02028	300.	10000.	89123124
	1990	0.02005	300.	10000.	90123124
	1991	0.02062	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.26496	310.	12000.	87080724
	1988	0.26345	280.	18000.	88091724
	1989	0.23358	340.	20000.	89030624
	1990	0.25138	300.	14000.	90051524
	1991	0.24019	40.	300.	91071224
HIGH 8-Hour					
	1987	0.61502	90.	500.	87071516
	1988	0.60617	280.	20000.	88091708
	1989	0.51024	250.	20000.	89011324
	1990	0.58728	140.	20000.	90121108
	1991	0.70110	40.	300.	91071224
HIGH 3-Hour					
	1987	1.64005	90.	500.	87071515
	1988	0.96996	310.	20000.	88091003
	1989	0.93870	280.	16000.	89091103
	1990	1.07256	270.	16000.	90031003
	1991	1.59000	40.	300.	91071218
HIGH 1-Hour					
	1987	4.92014	90.	500.	87071513
	1988	2.01675	200.	1500.	88032713
	1989	1.88643	200.	1500.	89070114
	1990	2.40886	140.	1500.	90072212
	1991	4.76999	40.	300.	91071217

SOURCE GROUP ID: LD5095

Annual					
	1987	0.01919	300.	10000.	87123124
	1988	0.01896	300.	10000.	88123124
	1989	0.02085	300.	10000.	89123124
	1990	0.02079	300.	10000.	90123124
	1991	0.02128	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.27057	310.	12000.	87080724
	1988	0.26996	280.	18000.	88091724
	1989	0.23963	340.	20000.	89030624
	1990	0.25783	300.	14000.	90051524
	1991	0.27066	40.	300.	91071224
HIGH 8-Hour					
	1987	0.68312	90.	500.	87071516
	1988	0.62144	280.	20000.	88091708
	1989	0.52431	250.	20000.	89011324
	1990	0.60305	140.	20000.	90121108
	1991	0.79653	40.	300.	91071224
HIGH 3-Hour					
	1987	1.82166	90.	500.	87071515
	1988	0.99438	310.	20000.	88091003
	1989	0.96234	280.	16000.	89091103
	1990	1.09942	270.	16000.	90031003
	1991	1.81308	40.	300.	91071218
HIGH 1-Hour					
	1987	5.46497	90.	500.	87071513
	1988	2.02952	200.	1500.	88032713
	1989	1.90323	200.	1500.	89070114
	1990	2.41958	140.	1500.	90072212
	1991	5.43925	40.	300.	91071217

All receptor computations reported with respect to a user-specified origin

GRID	-71.02	22.40
DISCRETE	0.00	0.00

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENGASC2.o87
ISCST3 OUTPUT FILE NUMBER 2 :GENGASC2.o88
ISCST3 OUTPUT FILE NUMBER 3 :GENGASC2.o89
ISCST3 OUTPUT FILE NUMBER 4 :GENGASC2.o90
ISCST3 OUTPUT FILE NUMBER 5 :GENGASC2.o91
First title for last output file is: 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS 2/7/00
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, NAT GAS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BASE35					
Annual					
	1987	0.01256	300.	10000.	87123124
	1988	0.01223	300.	12000.	88123124
	1989	0.01342	300.	12000.	89123124
	1990	0.01350	300.	12000.	90123124
	1991	0.01380	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.16738	310.	16000.	87080724
	1988	0.18082	280.	20000.	88091724
	1989	0.16804	340.	20000.	89030624
	1990	0.18557	300.	18000.	90051524
	1991	0.16544	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.39512	350.	20000.	87011624
	1988	0.44026	280.	20000.	88091708
	1989	0.39166	250.	20000.	89011324
	1990	0.42032	140.	20000.	90121108
	1991	0.36574	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.70553	310.	20000.	87060503
	1988	0.70564	160.	20000.	88102603
	1989	0.69468	280.	20000.	89091103
	1990	0.79839	270.	20000.	90031003
	1991	0.82044	160.	20000.	91011803
HIGH 1-Hour					
	1987	1.93866	90.	700.	87071513
	1988	1.11698	10.	5000.	88082111
	1989	1.07251	40.	5000.	89070311
	1990	1.64759	60.	2000.	90082313
	1991	1.74703	40.	700.	91071217
SOURCE GROUP ID: BASE59					
Annual					
	1987	0.01311	300.	10000.	87123124
	1988	0.01248	300.	12000.	88123124
	1989	0.01377	300.	10000.	89123124
	1990	0.01391	300.	12000.	90123124
	1991	0.01417	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.17054	310.	16000.	87080724
	1988	0.18471	280.	20000.	88091724
	1989	0.17179	340.	20000.	89030624
	1990	0.18919	300.	16000.	90051524
	1991	0.16907	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.40372	350.	20000.	87011624
	1988	0.44980	280.	20000.	88091708
	1989	0.40016	250.	20000.	89011324
	1990	0.42993	140.	20000.	90121108
	1991	0.37364	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.72047	310.	20000.	87060503
	1988	0.71998	160.	20000.	88102603
	1989	0.70837	280.	20000.	89091103
	1990	0.81411	270.	20000.	90031003
	1991	0.83826	160.	20000.	91011803
HIGH 1-Hour					
	1987	2.07599	90.	700.	87071513
	1988	1.11758	10.	5000.	88082111
	1989	1.07342	40.	5000.	89070311
	1990	1.65314	60.	2000.	90082313
	1991	1.84631	40.	500.	91071217
SOURCE GROUP ID: BASE95					

Annual					
	1987	0.01390	300.	10000.	87123124
	1988	0.01338	300.	12000.	88123124
	1989	0.01463	300.	10000.	89123124
	1990	0.01470	300.	12000.	90123124
	1991	0.01496	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.17829	310.	16000.	87080724
	1988	0.19424	280.	20000.	88091724
	1989	0.18127	340.	20000.	89030624
	1990	0.19817	300.	16000.	90051524
	1991	0.17793	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.42477	350.	20000.	87011624
	1988	0.47315	280.	20000.	88091708
	1989	0.42090	250.	20000.	89011324
	1990	0.46459	280.	6000.	90081616
	1991	0.39297	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.80241	90.	700.	87071515
	1988	0.75711	310.	20000.	88091003
	1989	0.74173	280.	20000.	89091103
	1990	0.85220	270.	20000.	90031003
	1991	0.88150	160.	20000.	91011803
HIGH 1-Hour					
	1987	2.40722	90.	700.	87071513
	1988	1.20120	280.	5000.	88082312
	1989	1.76340	200.	1500.	89070114
	1990	1.66637	60.	2000.	90082313
	1991	2.15320	40.	500.	91071217
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.01585	300.	10000.	87123124
	1988	0.01556	300.	10000.	88123124
	1989	0.01698	300.	10000.	89123124
	1990	0.01701	300.	10000.	90123124
	1991	0.01723	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.19742	310.	16000.	87080724
	1988	0.21766	280.	20000.	88091724
	1989	0.20372	340.	20000.	89030624
	1990	0.22054	300.	16000.	90051524
	1991	0.19960	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.47648	350.	20000.	87011624
	1988	0.53050	280.	20000.	88091708
	1989	0.47152	250.	20000.	89011324
	1990	0.51019	140.	20000.	90121108
	1991	0.44039	240.	20000.	91102808
HIGH 3-Hour					
	1987	1.07232	90.	700.	87071515
	1988	0.84892	310.	20000.	88091003
	1989	0.82560	280.	18000.	89091103
	1990	0.94577	270.	18000.	90031003
	1991	0.98602	160.	20000.	91011803
HIGH 1-Hour					
	1987	3.21696	90.	700.	87071513
	1988	1.96083	200.	1500.	88032713
	1989	1.80979	200.	1500.	89070114
	1990	2.08275	320.	1500.	90082412
	1991	2.88801	40.	500.	91071217
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.01603	300.	10000.	87123124
	1988	0.01580	300.	10000.	88123124
	1989	0.01738	300.	10000.	89123124
	1990	0.01722	300.	10000.	90123124
	1991	0.01745	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.19944	310.	16000.	87080724
	1988	0.22013	280.	20000.	88091724
	1989	0.20613	340.	20000.	89030624
	1990	0.22282	300.	16000.	90051524
	1991	0.20192	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.48204	350.	20000.	87011624
	1988	0.53657	280.	20000.	88091708

	1989	0.47696	250.	20000.	89011324
	1990	0.51648	140.	20000.	90121108
	1991	0.44547	240.	20000.	91102808
HIGH 3-Hour					
	1987	1.10846	90.	700.	87071515
	1988	0.85862	310.	20000.	88091003
	1989	0.83457	280.	18000.	89091103
	1990	0.95606	270.	18000.	90031003
	1991	0.99740	160.	20000.	91011803
HIGH 1-Hour					
	1987	3.32537	90.	700.	87071513
	1988	1.96474	200.	1500.	88032713
	1989	1.81536	200.	1500.	89070114
	1990	2.08682	320.	1500.	90082412
	1991	2.98997	40.	500.	91071217
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01664	300.	10000.	87123124
	1988	0.01631	300.	10000.	88123124
	1989	0.01816	300.	10000.	89123124
	1990	0.01786	300.	10000.	90123124
	1991	0.01843	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.20551	310.	14000.	87080724
	1988	0.22722	280.	20000.	88091724
	1989	0.21299	340.	20000.	89030624
	1990	0.22970	300.	16000.	90051524
	1991	0.20854	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.49789	350.	20000.	87011624
	1988	0.55393	280.	20000.	88091708
	1989	0.48779	250.	20000.	89011324
	1990	0.53427	140.	20000.	90121108
	1991	0.47948	40.	500.	91071224
HIGH 3-Hour					
	1987	1.21453	90.	500.	87071515
	1988	0.88636	310.	20000.	88091003
	1989	0.86015	280.	18000.	89091103
	1990	0.98527	270.	18000.	90031003
	1991	1.10173	40.	500.	91071218
HIGH 1-Hour					
	1987	3.64360	90.	500.	87071513
	1988	1.97654	200.	1500.	88032713
	1989	1.83193	200.	1500.	89070114
	1990	2.09908	320.	1500.	90082412
	1991	3.30519	40.	500.	91071217
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.01877	300.	10000.	87123124
	1988	0.01859	300.	10000.	88123124
	1989	0.02042	300.	10000.	89123124
	1990	0.02020	300.	10000.	90123124
	1991	0.02076	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.26629	310.	12000.	87080724
	1988	0.26499	280.	18000.	88091724
	1989	0.23498	340.	20000.	89030624
	1990	0.25289	300.	14000.	90051524
	1991	0.24280	40.	300.	91071224
HIGH 8-Hour					
	1987	0.62256	90.	500.	87071516
	1988	0.60978	280.	20000.	88091708
	1989	0.51348	250.	20000.	89011324
	1990	0.59078	140.	20000.	90121108
	1991	0.70923	40.	300.	91071224
HIGH 3-Hour					
	1987	1.66016	90.	500.	87071515
	1988	0.97575	310.	20000.	88091003
	1989	0.94428	280.	16000.	89091103
	1990	1.07874	270.	16000.	90031003
	1991	1.60905	40.	300.	91071218
HIGH 1-Hour					
	1987	4.98049	90.	500.	87071513
	1988	2.01976	200.	1500.	88032713
	1989	1.89044	200.	1500.	89070114
	1990	2.41144	140.	1500.	90072212
	1991	4.82714	40.	300.	91071217

SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.01892	300.	10000.	87123124
	1988	0.01872	300.	10000.	88123124
	1989	0.02057	300.	10000.	89123124
	1990	0.02036	300.	10000.	90123124
	1991	0.02099	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.26780	310.	12000.	87080724
	1988	0.26676	280.	18000.	88091724
	1989	0.23664	340.	20000.	89030624
	1990	0.25465	300.	14000.	90051524
	1991	0.25378	40.	300.	91071224
HIGH 8-Hour					
	1987	0.64613	90.	500.	87071516
	1988	0.61392	280.	20000.	88091708
	1989	0.51735	250.	20000.	89011324
	1990	0.59520	140.	20000.	90121108
	1991	0.74365	40.	300.	91071224
HIGH 3-Hour					
	1987	1.72301	90.	500.	87071515
	1988	0.98237	310.	20000.	88091003
	1989	0.95070	280.	16000.	89091103
	1990	1.08614	270.	16000.	90031003
	1991	1.68948	40.	300.	91071218
HIGH 1-Hour					
	1987	5.16904	90.	500.	87071513
	1988	2.02320	200.	1500.	88032713
	1989	1.89495	200.	1500.	89070114
	1990	2.41429	140.	1500.	90072212
	1991	5.06844	40.	300.	91071217
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01963	300.	8000.	87123124
	1988	0.01951	300.	10000.	88123124
	1989	0.02154	300.	10000.	89123124
	1990	0.02139	300.	10000.	90123124
	1991	0.02175	300.	10000.	91123124
HIGH 24-Hour					
	1987	0.27481	310.	12000.	87080724
	1988	0.27480	280.	18000.	88091724
	1989	0.24410	340.	20000.	89030624
	1990	0.26263	300.	14000.	90051524
	1991	0.29067	40.	300.	91071224
HIGH 8-Hour					
	1987	0.72881	90.	500.	87071516
	1988	0.63277	280.	20000.	88091708
	1989	0.53471	250.	20000.	89011324
	1990	0.61463	140.	20000.	90121108
	1991	0.85919	40.	300.	91071224
HIGH 3-Hour					
	1987	1.94350	90.	500.	87071515
	1988	1.01252	310.	20000.	88091003
	1989	0.97989	280.	16000.	89091103
	1990	1.11922	270.	16000.	90031003
	1991	1.95960	40.	300.	91071218
HIGH 1-Hour					
	1987	5.83049	90.	500.	87071513
	1988	2.03925	200.	1500.	88032713
	1989	1.91597	200.	1500.	89070114
	1990	2.42778	140.	1500.	90072212
	1991	5.87881	40.	300.	91071217
SOURCE GROUP ID:	HPM35				
Annual					
	1987	0.01231	300.	10000.	87123124
	1988	0.01186	300.	12000.	88123124
	1989	0.01320	300.	12000.	89123124
	1990	0.01327	300.	12000.	90123124
	1991	0.01348	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.16504	310.	18000.	87080724
	1988	0.17789	280.	20000.	88091724
	1989	0.16525	340.	20000.	89030624
	1990	0.18290	300.	18000.	90051524
	1991	0.16275	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.38872	350.	20000.	87011624

	1988	0.43308	280.	20000.	88091708
	1989	0.38536	250.	20000.	89011324
	1990	0.41340	140.	20000.	90121108
	1991	0.35986	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.69435	310.	20000.	87060503
	1988	0.69501	160.	20000.	88102603
	1989	0.68434	280.	20000.	89091103
	1990	0.78675	270.	20000.	90031003
	1991	0.80748	160.	20000.	91011803
HIGH 1-Hour					
	1987	1.86273	90.	1000.	87071513
	1988	1.10404	270.	5000.	88060313
	1989	1.07198	40.	5000.	89070311
	1990	1.64324	60.	2000.	90082313
	1991	1.69068	40.	700.	91071217
SOURCE GROUP ID:	HPM59				
Annual					
	1987	0.01254	300.	10000.	87123124
	1988	0.01220	300.	12000.	88123124
	1989	0.01340	300.	12000.	89123124
	1990	0.01348	300.	12000.	90123124
	1991	0.01377	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.16711	310.	16000.	87080724
	1988	0.18051	280.	20000.	88091724
	1989	0.16778	340.	20000.	89030624
	1990	0.18530	300.	18000.	90051524
	1991	0.16520	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.39452	350.	20000.	87011624
	1988	0.43949	280.	20000.	88091708
	1989	0.39110	250.	20000.	89011324
	1990	0.41992	140.	20000.	90121108
	1991	0.36518	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.70441	310.	20000.	87060503
	1988	0.70472	160.	20000.	88102603
	1989	0.69358	280.	20000.	89091103
	1990	0.79739	270.	20000.	90031003
	1991	0.81957	160.	20000.	91011803
HIGH 1-Hour					
	1987	1.95546	90.	700.	87071513
	1988	1.11694	10.	5000.	88082111
	1989	1.07244	40.	5000.	89070311
	1990	1.64701	60.	2000.	90082313
	1991	1.76006	40.	700.	91071217
SOURCE GROUP ID:	HPM95				
Annual					
	1987	0.01315	300.	10000.	87123124
	1988	0.01251	300.	12000.	88123124
	1989	0.01386	300.	10000.	89123124
	1990	0.01396	300.	12000.	90123124
	1991	0.01421	300.	12000.	91123124
HIGH 24-Hour					
	1987	0.17098	310.	16000.	87080724
	1988	0.18527	280.	20000.	88091724
	1989	0.17238	340.	20000.	89030624
	1990	0.18968	300.	16000.	90051524
	1991	0.16964	310.	20000.	91032724
HIGH 8-Hour					
	1987	0.40506	350.	20000.	87011624
	1988	0.45116	280.	20000.	88091708
	1989	0.40152	250.	20000.	89011324
	1990	0.43171	140.	20000.	90121108
	1991	0.37486	240.	20000.	91102808
HIGH 3-Hour					
	1987	0.72271	310.	20000.	87060503
	1988	0.72229	160.	20000.	88102603
	1989	0.71034	280.	20000.	89091103
	1990	0.81664	270.	20000.	90031003
	1991	0.84142	160.	20000.	91011803
HIGH 1-Hour					
	1987	2.12532	90.	700.	87071513
	1988	1.11768	10.	5000.	88082111
	1989	1.07356	40.	5000.	89070311
	1990	1.65380	60.	2000.	90082313

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                 1991     1.89786          40.        500.      91071217
 All receptor computations reported with respect to a user-specified origin
GRID            -71.02          22.40
DISCRETE          0.00           0.00
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ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENOILC1.o87
ISCST3 OUTPUT FILE NUMBER 2 :GENOILC1.o88
ISCST3 OUTPUT FILE NUMBER 3 :GENOILC1.o89
ISCST3 OUTPUT FILE NUMBER 4 :GENOILC1.o90
ISCST3 OUTPUT FILE NUMBER 5 :GENOILC1.o91
First title for last output file is: 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS 2/7/00
Second title for last output file is: PSD CLASS I SIGN. IMPACT ANALYSIS,EVERGLADES NP, GEN 10G/S,FUEL OIL

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE35				
Annual					
	1987	0.00088	454000.	2863200.	87123124
	1988	0.00102	540000.	2848600.	88123124
	1989	0.00116	550300.	2848600.	89123124
	1990	0.00135	545000.	2848600.	90123124
	1991	0.00102	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05185	473500.	2860000.	87100424
	1988	0.03458	505000.	2832500.	88070424
	1989	0.02726	495000.	2832500.	89042224
	1990	0.03162	540000.	2848600.	90020724
	1991	0.04228	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09792	473500.	2860000.	87100424
	1988	0.09386	505000.	2832500.	88070424
	1989	0.08624	469000.	2860000.	89123008
	1990	0.09485	540000.	2848600.	90020708
	1991	0.08746	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19502	473500.	2857000.	87100424
	1988	0.19965	464000.	2860000.	88110821
	1989	0.17482	530000.	2848600.	89101509
	1990	0.25294	540000.	2848600.	90020706
	1991	0.22398	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.50897	548600.	2837500.	87091322
	1988	0.48888	543500.	2824600.	88042207
	1989	0.52447	530000.	2848600.	89101507
	1990	0.52562	540000.	2848600.	90012223
	1991	0.52476	550300.	2848600.	91070707
SOURCE GROUP ID:	BASE59				
Annual					
	1987	0.00090	545000.	2848600.	87123124
	1988	0.00105	540000.	2848600.	88123124
	1989	0.00119	550300.	2848600.	89123124
	1990	0.00137	545000.	2848600.	90123124
	1991	0.00104	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05229	473500.	2860000.	87100424
	1988	0.03487	505000.	2832500.	88070424
	1989	0.02763	495000.	2832500.	89042224
	1990	0.03198	540000.	2848600.	90020724
	1991	0.04313	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09872	473500.	2860000.	87100424
	1988	0.09472	505000.	2832500.	88070424
	1989	0.08747	469000.	2860000.	89123008
	1990	0.09594	540000.	2848600.	90020708
	1991	0.08871	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19658	473500.	2857000.	87100424
	1988	0.20239	464000.	2860000.	88110821
	1989	0.17733	530000.	2848600.	89101509
	1990	0.25583	540000.	2848600.	90020706
	1991	0.22717	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.51606	548600.	2837500.	87091322
	1988	0.49551	543500.	2824600.	88042207
	1989	0.53198	530000.	2848600.	89101507
	1990	0.53320	540000.	2848600.	90012223
	1991	0.53225	550300.	2848600.	91070707
SOURCE GROUP ID:	BASE95				

Annual					
	1987	0.00094	454000.	2863200.	87123124
	1988	0.00110	540000.	2848600.	88123124
	1989	0.00124	550300.	2848600.	89123124
	1990	0.00146	545000.	2848600.	90123124
	1991	0.00108	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05359	473500.	2860000.	87100424
	1988	0.03572	505000.	2832500.	88070424
	1989	0.03258	469000.	2860000.	89113024
	1990	0.03305	540000.	2848600.	90020724
	1991	0.04571	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10107	473500.	2860000.	87100424
	1988	0.09728	505000.	2832500.	88070424
	1989	0.09112	469000.	2860000.	89123008
	1990	0.09916	540000.	2848600.	90020708
	1991	0.09248	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.20172	545000.	2848600.	87031421
	1988	0.21063	464000.	2860000.	88110821
	1989	0.18487	530000.	2848600.	89101509
	1990	0.26443	540000.	2848600.	90020706
	1991	0.23685	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.53739	548600.	2837500.	87091322
	1988	0.51535	543500.	2824600.	88042207
	1989	0.55461	530000.	2848600.	89101507
	1990	0.55592	540000.	2848600.	90012223
	1991	0.55490	550300.	2848600.	91070707
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.00102	545000.	2848600.	87123124
	1988	0.00119	540000.	2848600.	88123124
	1989	0.00141	550300.	2848600.	89123124
	1990	0.00161	545000.	2848600.	90123124
	1991	0.00119	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05595	473500.	2860000.	87100424
	1988	0.03728	505000.	2832500.	88070424
	1989	0.03635	469000.	2860000.	89113024
	1990	0.03503	540000.	2848600.	90020724
	1991	0.05473	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10533	473500.	2860000.	87100424
	1988	0.10196	505000.	2832500.	88070424
	1989	0.09789	469000.	2860000.	89123008
	1990	0.10508	540000.	2848600.	90020708
	1991	0.09959	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.21144	545000.	2848600.	87031421
	1988	0.22616	464000.	2860000.	88110821
	1989	0.19901	530000.	2848600.	89101509
	1990	0.28021	540000.	2848600.	90020706
	1991	0.25522	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.57729	548600.	2837500.	87091322
	1988	0.55217	543500.	2824600.	88042207
	1989	0.59703	530000.	2848600.	89101507
	1990	0.59838	540000.	2848600.	90012223
	1991	0.59751	550300.	2848600.	91070707
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.00111	545000.	2848600.	87123124
	1988	0.00129	540000.	2848600.	88123124
	1989	0.00154	550300.	2848600.	89123124
	1990	0.00173	545000.	2848600.	90123124
	1991	0.00127	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05832	473500.	2860000.	87100424
	1988	0.03917	505000.	2832500.	88070424
	1989	0.03737	469000.	2860000.	89113024
	1990	0.03707	540000.	2848600.	90020724
	1991	0.06033	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10962	473500.	2860000.	87100424
	1988	0.10675	505000.	2832500.	88070424

	1989	0.10506	469000.	2860000.	89123008
	1990	0.11333	545000.	2848600.	90030424
	1991	0.10709	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22139	545000.	2848600.	87031421
	1988	0.24283	464000.	2860000.	88110821
	1989	0.21397	530000.	2848600.	89101509
	1990	0.29658	540000.	2848600.	90020706
	1991	0.27500	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.61938	548600.	2837500.	87091322
	1988	0.59094	543500.	2824600.	88042207
	1989	0.64190	530000.	2848600.	89101507
	1990	0.64335	540000.	2848600.	90012223
	1991	0.64256	550300.	2848600.	91070707
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.00107	545000.	2848600.	87123124
	1988	0.00122	540000.	2848600.	88123124
	1989	0.00146	550300.	2848600.	89123124
	1990	0.00165	545000.	2848600.	90123124
	1991	0.00122	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05682	473500.	2860000.	87100424
	1988	0.03787	505000.	2832500.	88070424
	1989	0.03672	469000.	2860000.	89113024
	1990	0.03578	540000.	2848600.	90020724
	1991	0.05674	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10691	473500.	2860000.	87100424
	1988	0.10371	505000.	2832500.	88070424
	1989	0.10054	469000.	2860000.	89123008
	1990	0.10734	540000.	2848600.	90020708
	1991	0.10230	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.21514	545000.	2848600.	87031421
	1988	0.23223	464000.	2860000.	88110821
	1989	0.20445	530000.	2848600.	89101509
	1990	0.28625	540000.	2848600.	90020706
	1991	0.26237	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.59262	548600.	2837500.	87091322
	1988	0.56641	543500.	2824600.	88042207
	1989	0.61336	530000.	2848600.	89101507
	1990	0.61482	540000.	2848600.	90012223
	1991	0.61383	550300.	2848600.	91070707
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.00114	545000.	2848600.	87123124
	1988	0.00132	540000.	2848600.	88123124
	1989	0.00159	550300.	2848600.	89123124
	1990	0.00177	545000.	2848600.	90123124
	1991	0.00131	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05897	473500.	2860000.	87100424
	1988	0.03961	505000.	2832500.	88070424
	1989	0.03765	469000.	2860000.	89113024
	1990	0.03765	540000.	2848600.	90020724
	1991	0.06197	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.11080	473500.	2860000.	87100424
	1988	0.10806	505000.	2832500.	88070424
	1989	0.10711	469000.	2860000.	89123008
	1990	0.11666	545000.	2848600.	90030424
	1991	0.10921	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22416	545000.	2848600.	87031421
	1988	0.25097	540000.	2848600.	88120803
	1989	0.21819	530000.	2848600.	89101509
	1990	0.30117	540000.	2848600.	90020706
	1991	0.28066	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.63124	548600.	2837500.	87091322
	1988	0.60191	543500.	2824600.	88042207
	1989	0.65457	530000.	2848600.	89101507
	1990	0.65609	540000.	2848600.	90012223
	1991	0.65523	550300.	2848600.	91070707

SOURCE GROUP ID: LD5059

Annual					
	1987	0.00114	545000.	2848600.	87123124
	1988	0.00132	540000.	2848600.	88123124
	1989	0.00159	550300.	2848600.	89123124
	1990	0.00177	545000.	2848600.	90123124
	1991	0.00132	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05909	473500.	2860000.	87100424
	1988	0.03969	505000.	2832500.	88070424
	1989	0.03771	469000.	2860000.	89113024
	1990	0.03776	540000.	2848600.	90020724
	1991	0.06228	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.11103	473500.	2860000.	87100424
	1988	0.10832	505000.	2832500.	88070424
	1989	0.10750	469000.	2860000.	89123008
	1990	0.11731	545000.	2848600.	90030424
	1991	0.10961	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22470	545000.	2848600.	87031421
	1988	0.25260	540000.	2848600.	88120803
	1989	0.21901	530000.	2848600.	89101509
	1990	0.30205	540000.	2848600.	90020706
	1991	0.28175	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.63353	548600.	2837500.	87091322
	1988	0.60404	543500.	2824600.	88042207
	1989	0.65702	530000.	2848600.	89101507
	1990	0.65857	540000.	2848600.	90012223
	1991	0.65766	550300.	2848600.	91070707

SOURCE GROUP ID: LD5095

Annual					
	1987	0.00116	545000.	2848600.	87123124
	1988	0.00134	540000.	2848600.	88123124
	1989	0.00162	550300.	2848600.	89123124
	1990	0.00182	545000.	2848600.	90123124
	1991	0.00137	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05974	473500.	2860000.	87100424
	1988	0.04005	505000.	2832500.	88070424
	1989	0.03794	469000.	2860000.	89113024
	1990	0.03823	540000.	2848600.	90020724
	1991	0.06366	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.11199	473500.	2860000.	87100424
	1988	0.11044	475000.	2854000.	88070224
	1989	0.10919	469000.	2860000.	89123008
	1990	0.12010	545000.	2848600.	90030424
	1991	0.11136	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22696	545000.	2848600.	87031421
	1988	0.25951	540000.	2848600.	88120803
	1989	0.22250	530000.	2848600.	89101509
	1990	0.30581	540000.	2848600.	90020706
	1991	0.28646	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.64333	548600.	2837500.	87091322
	1988	0.61308	543500.	2824600.	88042207
	1989	0.66750	530000.	2848600.	89101507
	1990	0.66909	540000.	2848600.	90012223
	1991	0.66816	550300.	2848600.	91070707

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENGASC1.o87
ISCST3 OUTPUT FILE NUMBER 2 :GENGASC1.o88
ISCST3 OUTPUT FILE NUMBER 3 :GENGASC1.o89
ISCST3 OUTPUT FILE NUMBER 4 :GENGASC1.o90
ISCST3 OUTPUT FILE NUMBER 5 :GENGASC1.o91
First title for last output file is: 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS 2/7/00
Second title for last output file is: PSD CLASS I SIGN. IMPACT ANALYSIS, EVERGLADES NP, GEN 10G/S, NAT GAS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE35				
Annual					
	1987	0.00090	545000.	2848600.	87123124
	1988	0.00105	540000.	2848600.	88123124
	1989	0.00119	550300.	2848600.	89123124
	1990	0.00138	545000.	2848600.	90123124
	1991	0.00104	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05235	473500.	2860000.	87100424
	1988	0.03491	505000.	2832500.	88070424
	1989	0.02768	495000.	2832500.	89042224
	1990	0.03203	540000.	2848600.	90020724
	1991	0.04324	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09883	473500.	2860000.	87100424
	1988	0.09484	505000.	2832500.	88070424
	1989	0.08764	469000.	2860000.	89123008
	1990	0.09609	540000.	2848600.	90020708
	1991	0.08888	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19680	473500.	2857000.	87100424
	1988	0.20276	464000.	2860000.	88110821
	1989	0.17768	530000.	2848600.	89101509
	1990	0.25623	540000.	2848600.	90020706
	1991	0.22762	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.51705	548600.	2837500.	87091322
	1988	0.49642	543500.	2824600.	88042207
	1989	0.53303	530000.	2848600.	89101507
	1990	0.53424	540000.	2848600.	90012223
	1991	0.53331	550300.	2848600.	91070707
SOURCE GROUP ID:	BASE59				
Annual					
	1987	0.00092	454000.	2863200.	87123124
	1988	0.00107	540000.	2848600.	88123124
	1989	0.00121	550300.	2848600.	89123124
	1990	0.00141	545000.	2848600.	90123124
	1991	0.00105	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05280	473500.	2860000.	87100424
	1988	0.03520	505000.	2832500.	88070424
	1989	0.02805	495000.	2832500.	89042224
	1990	0.03240	540000.	2848600.	90020724
	1991	0.04412	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09964	473500.	2860000.	87100424
	1988	0.09572	505000.	2832500.	88070424
	1989	0.08889	469000.	2860000.	89123008
	1990	0.09720	540000.	2848600.	90020708
	1991	0.09017	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19846	545000.	2848600.	87031421
	1988	0.20559	464000.	2860000.	88110821
	1989	0.18026	530000.	2848600.	89101509
	1990	0.25919	540000.	2848600.	90020706
	1991	0.23092	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.52436	548600.	2837500.	87091322
	1988	0.50325	543500.	2824600.	88042207
	1989	0.54078	530000.	2848600.	89101507
	1990	0.54204	540000.	2848600.	90012223
	1991	0.54104	550300.	2848600.	91070707
SOURCE GROUP ID:	BASE95				

Annual					
	1987	0.00096	454000.	2863200.	87123124
	1988	0.00110	540000.	2848600.	88123124
	1989	0.00126	550300.	2848600.	89123124
	1990	0.00147	545000.	2848600.	90123124
	1991	0.00109	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05386	473500.	2860000.	87100424
	1988	0.03590	505000.	2832500.	88070424
	1989	0.03269	469000.	2860000.	89113024
	1990	0.03328	540000.	2848600.	90020724
	1991	0.04626	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10156	473500.	2860000.	87100424
	1988	0.09781	505000.	2832500.	88070424
	1989	0.09189	469000.	2860000.	89123008
	1990	0.09983	540000.	2848600.	90020708
	1991	0.09327	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.20284	545000.	2848600.	87031421
	1988	0.21237	464000.	2860000.	88110821
	1989	0.18645	530000.	2848600.	89101509
	1990	0.26623	540000.	2848600.	90020706
	1991	0.23889	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.54187	548600.	2837500.	87091322
	1988	0.51953	543500.	2824600.	88042207
	1989	0.55936	530000.	2848600.	89101507
	1990	0.56071	540000.	2848600.	90012223
	1991	0.55965	550300.	2848600.	91070707
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.00104	545000.	2848600.	87123124
	1988	0.00121	540000.	2848600.	88123124
	1989	0.00144	550300.	2848600.	89123124
	1990	0.00162	545000.	2848600.	90123124
	1991	0.00120	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05627	473500.	2860000.	87100424
	1988	0.03750	505000.	2832500.	88070424
	1989	0.03649	469000.	2860000.	89113024
	1990	0.03530	540000.	2848600.	90020724
	1991	0.05546	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10590	473500.	2860000.	87100424
	1988	0.10260	505000.	2832500.	88070424
	1989	0.09884	469000.	2860000.	89123008
	1990	0.10590	540000.	2848600.	90020708
	1991	0.10058	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.21277	545000.	2848600.	87031421
	1988	0.22834	464000.	2860000.	88110821
	1989	0.20098	530000.	2848600.	89101509
	1990	0.28239	540000.	2848600.	90020706
	1991	0.25781	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.58286	548600.	2837500.	87091322
	1988	0.55730	543500.	2824600.	88042207
	1989	0.60295	530000.	2848600.	89101507
	1990	0.60431	540000.	2848600.	90012223
	1991	0.60346	550300.	2848600.	91070707
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.00105	545000.	2848600.	87123124
	1988	0.00121	540000.	2848600.	88123124
	1989	0.00145	550300.	2848600.	89123124
	1990	0.00164	545000.	2848600.	90123124
	1991	0.00120	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05651	473500.	2860000.	87100424
	1988	0.03766	505000.	2832500.	88070424
	1989	0.03659	469000.	2860000.	89113024
	1990	0.03551	540000.	2848600.	90020724
	1991	0.05601	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10634	473500.	2860000.	87100424
	1988	0.10308	505000.	2832500.	88070424

	1989	0.09957	469000.	2860000.	89123008
	1990	0.10652	540000.	2848600.	90020708
	1991	0.10133	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.21380	545000.	2848600.	87031421
	1988	0.23002	464000.	2860000.	88110821
	1989	0.20249	530000.	2848600.	89101509
	1990	0.28406	540000.	2848600.	90020706
	1991	0.25978	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.58708	548600.	2837500.	87091322
	1988	0.56124	543500.	2824600.	88042207
	1989	0.60746	530000.	2848600.	89101507
	1990	0.60886	540000.	2848600.	90012223
	1991	0.60795	550300.	2848600.	91070707
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.00108	545000.	2848600.	87123124
	1988	0.00124	540000.	2848600.	88123124
	1989	0.00150	550300.	2848600.	89123124
	1990	0.00167	545000.	2848600.	90123124
	1991	0.00123	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05718	473500.	2860000.	87100424
	1988	0.03840	505000.	2832500.	88070424
	1989	0.03688	469000.	2860000.	89113024
	1990	0.03609	540000.	2848600.	90020724
	1991	0.05758	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.10757	473500.	2860000.	87100424
	1988	0.10444	505000.	2832500.	88070424
	1989	0.10162	469000.	2860000.	89123008
	1990	0.10827	540000.	2848600.	90020708
	1991	0.10344	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.21665	545000.	2848600.	87031421
	1988	0.23475	464000.	2860000.	88110821
	1989	0.20672	530000.	2848600.	89101509
	1990	0.28873	540000.	2848600.	90020706
	1991	0.26536	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.59900	548600.	2837500.	87091322
	1988	0.57229	543500.	2824600.	88042207
	1989	0.62015	530000.	2848600.	89101507
	1990	0.62163	540000.	2848600.	90012223
	1991	0.62065	550300.	2848600.	91070707
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.00114	545000.	2848600.	87123124
	1988	0.00133	540000.	2848600.	88123124
	1989	0.00160	550300.	2848600.	89123124
	1990	0.00178	545000.	2848600.	90123124
	1991	0.00135	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05922	473500.	2860000.	87100424
	1988	0.03978	505000.	2832500.	88070424
	1989	0.03776	469000.	2860000.	89113024
	1990	0.03787	540000.	2848600.	90020724
	1991	0.06261	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.11126	473500.	2860000.	87100424
	1988	0.10870	475000.	2854000.	88070224
	1989	0.10789	469000.	2860000.	89123008
	1990	0.11795	545000.	2848600.	90030424
	1991	0.11003	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22521	545000.	2848600.	87031421
	1988	0.25417	540000.	2848600.	88120803
	1989	0.21983	530000.	2848600.	89101509
	1990	0.30292	540000.	2848600.	90020706
	1991	0.28285	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.63583	548600.	2837500.	87091322
	1988	0.60612	543500.	2824600.	88042207
	1989	0.65948	530000.	2848600.	89101507
	1990	0.66100	540000.	2848600.	90012223
	1991	0.66016	550300.	2848600.	91070707

SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.00115	545000.	2848600.	87123124
	1988	0.00133	540000.	2848600.	88123124
	1989	0.00161	550300.	2848600.	89123124
	1990	0.00180	545000.	2848600.	90123124
	1991	0.00136	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05948	473500.	2860000.	87100424
	1988	0.03987	505000.	2832500.	88070424
	1989	0.03783	469000.	2860000.	89113024
	1990	0.03800	540000.	2848600.	90020724
	1991	0.06298	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.11152	473500.	2860000.	87100424
	1988	0.10932	475000.	2854000.	88070224
	1989	0.10835	469000.	2860000.	89123008
	1990	0.11872	545000.	2848600.	90030424
	1991	0.11050	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22584	545000.	2848600.	87031421
	1988	0.25608	540000.	2848600.	88120803
	1989	0.22078	530000.	2848600.	89101509
	1990	0.30396	540000.	2848600.	90020706
	1991	0.28414	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.63852	548600.	2837500.	87091322
	1988	0.60862	543500.	2824600.	88042207
	1989	0.66235	530000.	2848600.	89101507
	1990	0.66391	540000.	2848600.	90012223
	1991	0.66301	550300.	2848600.	91070707
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.00117	545000.	2848600.	87123124
	1988	0.00137	540000.	2848600.	88123124
	1989	0.00163	550300.	2848600.	89123124
	1990	0.00184	545000.	2848600.	90123124
	1991	0.00138	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.06012	473500.	2860000.	87100424
	1988	0.04031	505000.	2832500.	88070424
	1989	0.03811	469000.	2860000.	89113024
	1990	0.03857	540000.	2848600.	90020724
	1991	0.06467	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.11269	473500.	2860000.	87100424
	1988	0.11212	475000.	2854000.	88070224
	1989	0.11040	469000.	2860000.	89123008
	1990	0.12214	545000.	2848600.	90030424
	1991	0.11264	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.22859	545000.	2848600.	87031421
	1988	0.26462	540000.	2848600.	88120803
	1989	0.22505	530000.	2848600.	89101509
	1990	0.30854	540000.	2848600.	90020706
	1991	0.28991	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.65050	548600.	2837500.	87091322
	1988	0.61964	543500.	2824600.	88042207
	1989	0.67516	530000.	2848600.	89101507
	1990	0.67677	540000.	2848600.	90012223
	1991	0.67587	550300.	2848600.	91070707
SOURCE GROUP ID:	HPM35				
Annual					
	1987	0.00088	454000.	2863200.	87123124
	1988	0.00103	540000.	2848600.	88123124
	1989	0.00117	550300.	2848600.	89123124
	1990	0.00136	545000.	2848600.	90123124
	1991	0.00103	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05201	473500.	2860000.	87100424
	1988	0.03469	505000.	2832500.	88070424
	1989	0.02740	495000.	2832500.	89042224
	1990	0.03175	540000.	2848600.	90020724
	1991	0.04259	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09821	473500.	2860000.	87100424

	1988	0.09417	505000.	2832500.	88070424
	1989	0.08671	469000.	2860000.	89123008
	1990	0.09526	540000.	2848600.	90020708
	1991	0.08790	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19559	473500.	2857000.	87100424
	1988	0.20066	464000.	2860000.	88110821
	1989	0.17573	530000.	2848600.	89101509
	1990	0.25401	540000.	2848600.	90020706
	1991	0.22514	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.51155	548600.	2837500.	87091322
	1988	0.49136	543500.	2824600.	88042207
	1989	0.52720	530000.	2848600.	89101507
	1990	0.52843	540000.	2848600.	90012223
	1991	0.52742	550300.	2848600.	91070707
SOURCE GROUP ID:	HPM59				
Annual					
	1987	0.00090	545000.	2848600.	87123124
	1988	0.00105	540000.	2848600.	88123124
	1989	0.00119	550300.	2848600.	89123124
	1990	0.00137	545000.	2848600.	90123124
	1991	0.00104	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05232	473500.	2860000.	87100424
	1988	0.03489	505000.	2832500.	88070424
	1989	0.02765	495000.	2832500.	89042224
	1990	0.03201	540000.	2848600.	90020724
	1991	0.04318	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09877	473500.	2860000.	87100424
	1988	0.09477	505000.	2832500.	88070424
	1989	0.08757	469000.	2860000.	89123008
	1990	0.09602	540000.	2848600.	90020708
	1991	0.08878	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19669	473500.	2857000.	87100424
	1988	0.20259	464000.	2860000.	88110821
	1989	0.17749	530000.	2848600.	89101509
	1990	0.25604	540000.	2848600.	90020706
	1991	0.22738	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.51652	548600.	2837500.	87091322
	1988	0.49602	543500.	2824600.	88042207
	1989	0.53247	530000.	2848600.	89101507
	1990	0.53374	540000.	2848600.	90012223
	1991	0.53267	550300.	2848600.	91070707
SOURCE GROUP ID:	HPM95				
Annual					
	1987	0.00092	545000.	2848600.	87123124
	1988	0.00107	540000.	2848600.	88123124
	1989	0.00121	550300.	2848600.	89123124
	1990	0.00141	545000.	2848600.	90123124
	1991	0.00106	550300.	2848600.	91123124
HIGH 24-Hour					
	1987	0.05287	473500.	2860000.	87100424
	1988	0.03525	505000.	2832500.	88070424
	1989	0.02811	495000.	2832500.	89042224
	1990	0.03246	540000.	2848600.	90020724
	1991	0.04425	491500.	2841000.	91101924
HIGH 8-Hour					
	1987	0.09976	473500.	2860000.	87100424
	1988	0.09584	505000.	2832500.	88070424
	1989	0.08911	469000.	2860000.	89123008
	1990	0.09738	540000.	2848600.	90020708
	1991	0.09036	550300.	2848600.	91070708
HIGH 3-Hour					
	1987	0.19878	545000.	2848600.	87031421
	1988	0.20605	464000.	2860000.	88110821
	1989	0.18065	530000.	2848600.	89101509
	1990	0.25967	540000.	2848600.	90020706
	1991	0.23142	469000.	2860000.	91102721
HIGH 1-Hour					
	1987	0.52546	548600.	2837500.	87091322
	1988	0.50438	543500.	2824600.	88042207
	1989	0.54195	530000.	2848600.	89101507
	1990	0.54329	540000.	2848600.	90012223

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                 1991     0.54213       550300.    2848600.     91070707
 All receptor computations reported with respect to a user-specified origin
GRID            0.00          0.00
DISCRETE        0.00          0.00
```

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CO STARTING
CO TITLEONE 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS          2/7/00
CO TITLETWO SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FUEL OIL
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF   .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** MODELING ORIGIN IS 71.02 M EAST OF PROPOSED SOUTH CT STACK
** RECEPTOR GRID IS CENTERED ON MIDPOINT BETWEEN PROPOSED CT STACKS
**  BYPASS STACK LETTER CODE
** ------------------------
**  A -  BYPS 1
**  B -  BYPS 2
**          SRCID SRCTYP          XS          YS        ZS
**   UTM                          (m)         (m)       (m)
SO LOCATION  BASE35A  POINT     -71.02        0.00     0.0
SO LOCATION  BASE35B  POINT     -71.02       44.81     0.0

SO LOCATION  BASE59A  POINT     -71.02        0.00     0.0
SO LOCATION  BASE59B  POINT     -71.02       44.81     0.0

SO LOCATION  BASE95A  POINT     -71.02        0.00     0.0
SO LOCATION  BASE95B  POINT     -71.02       44.81     0.0

SO LOCATION  LD7535A  POINT     -71.02        0.00     0.0
SO LOCATION  LD7535B  POINT     -71.02       44.81     0.0

SO LOCATION  LD7559A  POINT     -71.02        0.00     0.0
SO LOCATION  LD7559B  POINT     -71.02       44.81     0.0

SO LOCATION  LD7595A  POINT     -71.02        0.00     0.0
SO LOCATION  LD7595B  POINT     -71.02       44.81     0.0

SO LOCATION  LD5035A  POINT     -71.02        0.00     0.0
SO LOCATION  LD5035B  POINT     -71.02       44.81     0.0

SO LOCATION  LD5059A  POINT     -71.02        0.00     0.0
SO LOCATION  LD5059B  POINT     -71.02       44.81     0.0

SO LOCATION  LD5095A  POINT     -71.02        0.00     0.0
SO LOCATION  LD5095B  POINT     -71.02       44.81     0.0

** Source Parameter Cards:
** POINT:   SRCID          QS      HS        TS         VS        DS
**                        (g/s)    (m)       (K)       (m/s)      (m)
SO SRCPARAM   BASE35A      5.0     18.3      852.0      37.64     6.71
SO SRCPARAM   BASE35B      5.0     18.3      852.0      37.64     6.71

SO SRCPARAM   BASE59A      5.0     18.3      865.4      36.55     6.71
SO SRCPARAM   BASE59B      5.0     18.3      865.4      36.55     6.71

SO SRCPARAM   BASE95A      5.0     18.3      883.7      33.95     6.71
SO SRCPARAM   BASE95B      5.0     18.3      883.7      33.95     6.71

SO SRCPARAM   LD7535A      5.0     18.3      878.2      30.33     6.71
SO SRCPARAM   LD7535B      5.0     18.3      878.2      30.33     6.71

SO SRCPARAM   LD7559A      5.0     18.3      887.0      26.76     6.71
SO SRCPARAM   LD7559B      5.0     18.3      887.0      26.76     6.71

SO SRCPARAM   LD7595A      5.0     18.3      903.2      28.62     6.71
SO SRCPARAM   LD7595B      5.0     18.3      903.2      28.62     6.71

SO SRCPARAM   LD5035A      5.0     18.3      904.3      25.63     6.71
SO SRCPARAM   LD5035B      5.0     18.3      904.3      25.63     6.71

SO SRCPARAM   LD5059A      5.0     18.3      912.0      25.36     6.71
SO SRCPARAM   LD5059B      5.0     18.3      912.0      25.36     6.71

SO SRCPARAM   LD5095A      5.0     18.3      922.0      24.54     6.71
SO SRCPARAM   LD5095B      5.0     18.3      922.0      24.54     6.71
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SO BUILDHGT BASE35A-BASE95A       0.00   0.00   0.00   0.00   6.71   6.71
SO BUILDHGT BASE35A-BASE95A      16.76  16.76  16.76  16.76  16.76   6.71
SO BUILDHGT BASE35A-BASE95A      16.76  16.76  16.76   0.00   0.00   0.00
SO BUILDHGT BASE35A-BASE95A       0.00   0.00   0.00   0.00   6.71   6.71
SO BUILDHGT BASE35A-BASE95A      16.76   6.71   6.71   6.71  16.76   6.71
SO BUILDHGT BASE35A-BASE95A       6.71   0.00   0.00   0.00   0.00   0.00
SO BUILDWID BASE35A-BASE95A       0.00   0.00   0.00   0.00  14.06  13.41
SO BUILDWID BASE35A-BASE95A      15.58  15.47  14.63  15.47  15.58  13.41
SO BUILDWID BASE35A-BASE95A      15.13  14.07  12.59   0.00   0.00   0.00
SO BUILDWID BASE35A-BASE95A       0.00   0.00   0.00   0.00  14.06  13.41
SO BUILDWID BASE35A-BASE95A      15.58  10.91   9.14  10.91  15.58  13.41
SO BUILDWID BASE35A-BASE95A      14.06   0.00   0.00   0.00   0.00   0.00

SO BUILDHGT LD5035A-LD7595A       0.00   0.00   0.00   0.00   6.71   6.71
SO BUILDHGT LD5035A-LD7595A      16.76  16.76  16.76  16.76  16.76   6.71
SO BUILDHGT LD5035A-LD7595A      16.76  16.76  16.76   0.00   0.00   0.00
SO BUILDHGT LD5035A-LD7595A       0.00   0.00   0.00   0.00   6.71   6.71
SO BUILDHGT LD5035A-LD7595A      16.76   6.71   6.71   6.71  16.76   6.71
SO BUILDHGT LD5035A-LD7595A       6.71   0.00   0.00   0.00   0.00   0.00
SO BUILDWID LD5035A-LD7595A       0.00   0.00   0.00   0.00  14.06  13.41
SO BUILDWID LD5035A-LD7595A      15.58  15.47  14.63  15.47  15.58  13.41
SO BUILDWID LD5035A-LD7595A      15.13  14.07  12.59   0.00   0.00   0.00
SO BUILDWID LD5035A-LD7595A       0.00   0.00   0.00   0.00  14.06  13.41
SO BUILDWID LD5035A-LD7595A      15.58  10.91   9.14  10.91  15.58  13.41
SO BUILDWID LD5035A-LD7595A      14.06   0.00   0.00   0.00   0.00   0.00

SO BUILDHGT BASE35B-BASE95B       0.00   0.00  16.76  16.76  16.76   6.71
SO BUILDHGT BASE35B-BASE95B      16.76  16.76  16.76  16.76  16.76   6.71
SO BUILDHGT BASE35B-BASE95B       6.71   0.00   0.00   0.00   0.00   0.00
SO BUILDHGT BASE35B-BASE95B       0.00   0.00   0.00   0.00   6.71   6.71
SO BUILDHGT BASE35B-BASE95B      16.76   6.71   6.71   6.71  16.76   6.71
SO BUILDHGT BASE35B-BASE95B       6.71   0.00   0.00   0.00   0.00   0.00
SO BUILDWID BASE35B-BASE95B       0.00   0.00  12.59  14.07  15.13  13.41
SO BUILDWID BASE35B-BASE95B      15.58  15.47  14.63  15.47  15.58  13.41
SO BUILDWID BASE35B-BASE95B      14.06   0.00   0.00   0.00   0.00   0.00
SO BUILDWID BASE35B-BASE95B       0.00   0.00   0.00   0.00  14.06  13.41
SO BUILDWID BASE35B-BASE95B      15.58  10.91   9.14  10.91  15.58  13.41
SO BUILDWID BASE35B-BASE95B      14.06   0.00   0.00   0.00   0.00   0.00

SO BUILDHGT LD5035B-LD7595B       0.00   0.00  16.76  16.76  16.76   6.71
SO BUILDHGT LD5035B-LD7595B      16.76  16.76  16.76  16.76  16.76   6.71
SO BUILDHGT LD5035B-LD7595B       6.71   0.00   0.00   0.00   0.00   0.00
SO BUILDHGT LD5035B-LD7595B       0.00   0.00   0.00   0.00   6.71   6.71
SO BUILDHGT LD5035B-LD7595B      16.76   6.71   6.71   6.71  16.76   6.71
SO BUILDHGT LD5035B-LD7595B       6.71   0.00   0.00   0.00   0.00   0.00
SO BUILDWID LD5035B-LD7595B       0.00   0.00  12.59  14.07  15.13  13.41
SO BUILDWID LD5035B-LD7595B      15.58  15.47  14.63  15.47  15.58  13.41
SO BUILDWID LD5035B-LD7595B      14.06   0.00   0.00   0.00   0.00   0.00
SO BUILDWID LD5035B-LD7595B       0.00   0.00   0.00   0.00  14.06  13.41
SO BUILDWID LD5035B-LD7595B      15.58  10.91   9.14  10.91  15.58  13.41
SO BUILDWID LD5035B-LD7595B      14.06   0.00   0.00   0.00   0.00   0.00

SO EMISUNIT    .100000E+07 (GRAMS/SEC)        (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE35 BASE35A BASE35B
SO SRCGROUP BASE59 BASE59A BASE59B
SO SRCGROUP BASE95 BASE95A BASE95B
SO SRCGROUP LD7535 LD7535A LD7535B
SO SRCGROUP LD7559 LD7559A LD7559B
SO SRCGROUP LD7595 LD7595A LD7595B
SO SRCGROUP LD5035 LD5035A LD5035B
SO SRCGROUP LD5059 LD5059A LD5059B
SO SRCGROUP LD5095 LD5095A LD5095B
SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG  -71.02   22.40
RE GRIDPOLR POL DIST   200 300 500 700 1000 1200 1500 2000 2500 3000 3500 4000
RE GRIDPOLR POL DIST   5000 6000 8000 10000 12000 14000 16000 18000 20000 22000
RE GRIDPOLR POL DIST   24000 27000 30000
RE GRIDPOLR POL GDIR   36  10.00  10.00
RE GRIDPOLR POL END
RE FINISHED

ME STARTING
ME INPUTFIL D:\MET\PBIPBI87.MET
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ME ANEMHGHT     33  FEET
ME SURFDATA  12844  1987           WEST-PALM-BCH
ME UAIRDATA  12844  1987           WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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CO STARTING
CO TITLEONE 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS          2/7/00
CO TITLETWO SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, NAT GAS
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF   .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** MODELING ORIGIN IS 71.02 M EAST OF PROPOSED SOUTH CT STACK
** RECEPTOR GRID IS CENTERED ON MIDPOINT BETWEEN PROPOSED CT STACKS
**  BYPASS STACK LETTER CODE
** -----------------------
**  A -  BYPS 1
**  B -  BYPS 2
**          SRCID SRCTYP        XS          YS        ZS
**   UTM                        (m)         (m)       (m)
SO LOCATION  BASE35A  POINT    -71.02       0.00    0.0
SO LOCATION  BASE35B  POINT    -71.02      44.81    0.0

SO LOCATION  BASE59A  POINT    -71.02       0.00    0.0
SO LOCATION  BASE59B  POINT    -71.02      44.81    0.0

SO LOCATION  BASE95A  POINT    -71.02       0.00    0.0
SO LOCATION  BASE95B  POINT    -71.02      44.81    0.0

SO LOCATION  LD7535A  POINT    -71.02       0.00    0.0
SO LOCATION  LD7535B  POINT    -71.02      44.81    0.0

SO LOCATION  LD7559A  POINT    -71.02       0.00    0.0
SO LOCATION  LD7559B  POINT    -71.02      44.81    0.0

SO LOCATION  LD7595A  POINT    -71.02       0.00    0.0
SO LOCATION  LD7595B  POINT    -71.02      44.81    0.0

SO LOCATION  LD5035A  POINT    -71.02       0.00    0.0
SO LOCATION  LD5035B  POINT    -71.02      44.81    0.0

SO LOCATION  LD5059A  POINT    -71.02       0.00    0.0
SO LOCATION  LD5059B  POINT    -71.02      44.81    0.0

SO LOCATION  LD5095A  POINT    -71.02       0.00    0.0
SO LOCATION  LD5095B  POINT    -71.02      44.81    0.0

SO LOCATION  HPM35A   POINT    -71.02       0.00    0.0
SO LOCATION  HPM35B   POINT    -71.02      44.81    0.0

SO LOCATION  HPM59A   POINT    -71.02       0.00    0.0
SO LOCATION  HPM59B   POINT    -71.02      44.81    0.0

SO LOCATION  HPM95A   POINT    -71.02       0.00    0.0
SO LOCATION  HPM95B   POINT    -71.02      44.81    0.0

** Source Parameter Cards:
** POINT:   SRCID          QS     HS        TS        VS        DS
**                        (g/s)   (m)       (K)       (m/s)     (m)
SO SRCPARAM   BASE35A     5.0    18.3      863.7     36.48      6.71
SO SRCPARAM   BASE35B     5.0    18.3      863.7     36.48      6.71

SO SRCPARAM   BASE59A     5.0    18.3      875.4     35.45      6.71
SO SRCPARAM   BASE59B     5.0    18.3      875.4     35.45      6.71

SO SRCPARAM   BASE95A     5.0    18.3      890.4     33.38      6.71
SO SRCPARAM   BASE95B     5.0    18.3      890.4     33.38      6.71

SO SRCPARAM   LD7535A     5.0    18.3      878.7     29.84      6.71
SO SRCPARAM   LD7535B     5.0    18.3      878.7     29.84      6.71

SO SRCPARAM   LD7559A     5.0    18.3      888.2     29.32      6.71
SO SRCPARAM   LD7559B     5.0    18.3      888.2     29.32      6.71

SO SRCPARAM   LD7595A     5.0    18.3      905.4     28.07      6.71
SO SRCPARAM   LD7595B     5.0    18.3      905.4     28.07      6.71
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SO SRCPARAM   LD5035A    5.0    18.3     904.3     25.30     6.71
SO SRCPARAM   LD5035B    5.0    18.3     904.3     25.30     6.71

SO SRCPARAM   LD5059A    5.0    18.3     913.2     24.99     6.71
SO SRCPARAM   LD5059B    5.0    18.3     913.2     24.99     6.71

SO SRCPARAM   LD5095A    5.0    18.3     922.0     24.05     6.71
SO SRCPARAM   LD5095B    5.0    18.3     922.0     24.05     6.71

SO SRCPARAM   HPM35A     5.0    18.3     871.5     36.91     6.71
SO SRCPARAM   HPM35B     5.0    18.3     871.5     36.91     6.71

SO SRCPARAM   HPM59A     5.0    18.3     883.2     36.12     6.71
SO SRCPARAM   HPM59B     5.0    18.3     883.2     36.12     6.71

SO SRCPARAM   HPM95A     5.0    18.3     898.7     34.87     6.71
SO SRCPARAM   HPM95B     5.0    18.3     898.7     34.87     6.71

SO BUILDHGT BASE35A-BASE95A     0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35A-BASE95A    16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35A-BASE95A    16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT BASE35A-BASE95A     0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35A-BASE95A    16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT BASE35A-BASE95A     6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35A-BASE95A     0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35A-BASE95A    15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID BASE35A-BASE95A    15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID BASE35A-BASE95A     0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35A-BASE95A    15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID BASE35A-BASE95A    14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT LD5035A-LD7595A     0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035A-LD7595A    16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035A-LD7595A    16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT LD5035A-LD7595A     0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035A-LD7595A    16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT LD5035A-LD7595A     6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035A-LD7595A     0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035A-LD7595A    15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID LD5035A-LD7595A    15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID LD5035A-LD7595A     0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035A-LD7595A    15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID LD5035A-LD7595A    14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT BASE35B-BASE95B     0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35B-BASE95B    16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35B-BASE95B     6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT BASE35B-BASE95B     0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35B-BASE95B    16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT BASE35B-BASE95B     6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35B-BASE95B     0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID BASE35B-BASE95B    15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID BASE35B-BASE95B    14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35B-BASE95B     0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35B-BASE95B    15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID BASE35B-BASE95B    14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT LD5035B-LD7595B     0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035B-LD7595B    16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035B-LD7595B     6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT LD5035B-LD7595B     0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035B-LD7595B    16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT LD5035B-LD7595B     6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035B-LD7595B     0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID LD5035B-LD7595B    15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID LD5035B-LD7595B    14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035B-LD7595B     0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035B-LD7595B    15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID LD5035B-LD7595B    14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT HPM35A-HPM95A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT HPM35A-HPM95A      16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT HPM35A-HPM95A      16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT HPM35A-HPM95A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT HPM35A-HPM95A      16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT HPM35A-HPM95A       6.71    0.00    0.00    0.00    0.00    0.00
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SO BUILDWID HPM35A-HPM95A          0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID HPM35A-HPM95A         15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID HPM35A-HPM95A         15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID HPM35A-HPM95A          0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID HPM35A-HPM95A         15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID HPM35A-HPM95A         14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT HPM35B-HPM95B          0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT HPM35B-HPM95B         16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT HPM35B-HPM95B          6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT HPM35B-HPM95B          0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT HPM35B-HPM95B         16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT HPM35B-HPM95B          6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID HPM35B-HPM95B          0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID HPM35B-HPM95B         15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID HPM35B-HPM95B         14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID HPM35B-HPM95B          0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID HPM35B-HPM95B         15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID HPM35B-HPM95B         14.06    0.00    0.00    0.00    0.00    0.00

SO EMISUNIT    .100000E+07 (GRAMS/SEC)          (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE35 BASE35A BASE35B
SO SRCGROUP BASE59 BASE59A BASE59B
SO SRCGROUP BASE95 BASE95A BASE95B
SO SRCGROUP LD7535 LD7535A LD7535B
SO SRCGROUP LD7559 LD7559A LD7559B
SO SRCGROUP LD7595 LD7595A LD7595B
SO SRCGROUP LD5035 LD5035A LD5035B
SO SRCGROUP LD5059 LD5059A LD5059B
SO SRCGROUP LD5095 LD5095A LD5095B
SO SRCGROUP HPM35 HPM35A HPM35B
SO SRCGROUP HPM59 HPM59A HPM59B
SO SRCGROUP HPM95 HPM95A HPM95B
SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG  -71.02   22.40
RE GRIDPOLR POL DIST   200 300 500 700 1000 1200 1500 2000 2500 3000 3500 4000
RE GRIDPOLR POL DIST   5000 6000 8000 10000 12000 14000 16000 18000 20000 22000
RE GRIDPOLR POL DIST   24000 27000 30000
RE GRIDPOLR POL GDIR   36  10.00  10.00
RE GRIDPOLR POL END
RE FINISHED

ME STARTING
ME INPUTFIL D:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844  1987           WEST-PALM-BCH
ME UAIRDATA  12844  1987           WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

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CO STARTING
CO TITLEONE 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS          2/7/00
CO TITLETWO PSD CLASS I SIGN. IMPACT ANALYSIS,EVERGLADES NP, GEN 10G/S,FUEL OIL
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF   .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** MODELING ORIGIN IS 71.02 M EAST OF PROPOSED SOUTH CT STACK
** RECEPTOR GRID IS CENTERED ON MIDPOINT BETWEEN PROPOSED CT STACKS
**  BYPASS STACK LETTER CODE
** -----------------------
**  A -  BYPS 1
**  B -  BYPS 2
**          SRCID SRCTYP         XS          YS       ZS
**   UTM                         (m)         (m)      (m)
SO LOCATION  BASE35A  POINT     543100      2992900  0.0
SO LOCATION  BASE35B  POINT     543100      2992900  0.0

SO LOCATION  BASE59A  POINT     543100      2992900  0.0
SO LOCATION  BASE59B  POINT     543100      2992900  0.0

SO LOCATION  BASE95A  POINT     543100      2992900  0.0
SO LOCATION  BASE95B  POINT     543100      2992900  0.0

SO LOCATION  LD7535A  POINT     543100      2992900  0.0
SO LOCATION  LD7535B  POINT     543100      2992900  0.0

SO LOCATION  LD7559A  POINT     543100      2992900  0.0
SO LOCATION  LD7559B  POINT     543100      2992900  0.0

SO LOCATION  LD7595A  POINT     543100      2992900  0.0
SO LOCATION  LD7595B  POINT     543100      2992900  0.0

SO LOCATION  LD5035A  POINT     543100      2992900  0.0
SO LOCATION  LD5035B  POINT     543100      2992900  0.0

SO LOCATION  LD5059A  POINT     543100      2992900  0.0
SO LOCATION  LD5059B  POINT     543100      2992900  0.0

SO LOCATION  LD5095A  POINT     543100      2992900  0.0
SO LOCATION  LD5095B  POINT     543100      2992900  0.0

** Source Parameter Cards:
** POINT:   SRCID          QS      HS       TS        VS       DS
**                        (g/s)    (m)      (K)      (m/s)     (m)
SO SRCPARAM    BASE35A     5.0     18.3     852.0     37.64     6.71
SO SRCPARAM    BASE35B     5.0     18.3     852.0     37.64     6.71

SO SRCPARAM    BASE59A     5.0     18.3     865.4     36.55     6.71
SO SRCPARAM    BASE59B     5.0     18.3     865.4     36.55     6.71

SO SRCPARAM    BASE95A     5.0     18.3     883.7     33.95     6.71
SO SRCPARAM    BASE95B     5.0     18.3     883.7     33.95     6.71

SO SRCPARAM    LD7535A     5.0     18.3     878.2     30.33     6.71
SO SRCPARAM    LD7535B     5.0     18.3     878.2     30.33     6.71

SO SRCPARAM    LD7559A     5.0     18.3     887.0     26.76     6.71
SO SRCPARAM    LD7559B     5.0     18.3     887.0     26.76     6.71

SO SRCPARAM    LD7595A     5.0     18.3     903.2     28.62     6.71
SO SRCPARAM    LD7595B     5.0     18.3     903.2     28.62     6.71

SO SRCPARAM    LD5035A     5.0     18.3     904.3     25.63     6.71
SO SRCPARAM    LD5035B     5.0     18.3     904.3     25.63     6.71

SO SRCPARAM    LD5059A     5.0     18.3     912.0     25.36     6.71
SO SRCPARAM    LD5059B     5.0     18.3     912.0     25.36     6.71

SO SRCPARAM    LD5095A     5.0     18.3     922.0     24.54     6.71
SO SRCPARAM    LD5095B     5.0     18.3     922.0     24.54     6.71
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SO BUILDHGT BASE35A-BASE95A      0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35A-BASE95A     16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35A-BASE95A     16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT BASE35A-BASE95A      0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35A-BASE95A     16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT BASE35A-BASE95A      6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35A-BASE95A      0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35A-BASE95A     15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID BASE35A-BASE95A     15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID BASE35A-BASE95A      0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35A-BASE95A     15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID BASE35A-BASE95A     14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT LD5035A-LD7595A      0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035A-LD7595A     16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035A-LD7595A     16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT LD5035A-LD7595A      0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035A-LD7595A     16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT LD5035A-LD7595A      6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035A-LD7595A      0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035A-LD7595A     15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID LD5035A-LD7595A     15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID LD5035A-LD7595A      0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035A-LD7595A     15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID LD5035A-LD7595A     14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT BASE35B-BASE95B      0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35B-BASE95B     16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35B-BASE95B      6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT BASE35B-BASE95B      0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35B-BASE95B     16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT BASE35B-BASE95B      6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35B-BASE95B      0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID BASE35B-BASE95B     15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID BASE35B-BASE95B     14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35B-BASE95B      0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35B-BASE95B     15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID BASE35B-BASE95B     14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT LD5035B-LD7595B      0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035B-LD7595B     16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035B-LD7595B      6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT LD5035B-LD7595B      0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035B-LD7595B     16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT LD5035B-LD7595B      6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035B-LD7595B      0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID LD5035B-LD7595B     15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID LD5035B-LD7595B     14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035B-LD7595B      0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035B-LD7595B     15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID LD5035B-LD7595B     14.06    0.00    0.00    0.00    0.00    0.00

SO EMISUNIT    .100000E+07 (GRAMS/SEC)          (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE35 BASE35A BASE35B
SO SRCGROUP BASE59 BASE59A BASE59B
SO SRCGROUP BASE95 BASE95A BASE95B
SO SRCGROUP LD7535 LD7535A LD7535B
SO SRCGROUP LD7559 LD7559A LD7559B
SO SRCGROUP LD7595 LD7595A LD7595B
SO SRCGROUP LD5035 LD5035A LD5035B
SO SRCGROUP LD5059 LD5059A LD5059B
SO SRCGROUP LD5095 LD5095A LD5095B
SO FINISHED

RE STARTING
RE DISCCART   557000.00 2789000.00
RE DISCCART   556600.00 2792000.00
RE DISCCART   556000.00 2796000.00
RE DISCCART   553000.00 2796500.00
RE DISCCART   548000.00 2796500.00
RE DISCCART   542700.00 2796500.00
RE DISCCART   542700.00 2800000.00
RE DISCCART   542700.00 2805000.00
RE DISCCART   542700.00 2810000.00
RE DISCCART   542000.00 2811000.00
RE DISCCART   541300.00 2814000.00
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RE DISCCART   542700.00 2816000.00
RE DISCCART   544100.00 2820000.00
RE DISCCART   543500.00 2824600.00
RE DISCCART   545000.00 2829000.00
RE DISCCART   545700.00 2832200.00
RE DISCCART   546200.00 2835700.00
RE DISCCART   548600.00 2837500.00
RE DISCCART   550300.00 2839000.00
RE DISCCART   545000.00 2839000.00
RE DISCCART   540000.00 2839000.00
RE DISCCART   550500.00 2844000.00
RE DISCCART   545000.00 2844000.00
RE DISCCART   540000.00 2844000.00
RE DISCCART   550300.00 2848600.00
RE DISCCART   545000.00 2848600.00
RE DISCCART   540000.00 2848600.00
RE DISCCART   535000.00 2848600.00
RE DISCCART   530000.00 2848600.00
RE DISCCART   525000.00 2848600.00
RE DISCCART   520000.00 2848600.00
RE DISCCART   514500.00 2848600.00
RE DISCCART   514500.00 2843000.00
RE DISCCART   514500.00 2838000.00
RE DISCCART   514500.00 2832500.00
RE DISCCART   510000.00 2832500.00
RE DISCCART   505000.00 2832500.00
RE DISCCART   500000.00 2832500.00
RE DISCCART   495000.00 2832500.00
RE DISCCART   494500.00 2837000.00
RE DISCCART   491500.00 2841000.00
RE DISCCART   488500.00 2845500.00
RE DISCCART   483000.00 2848500.00
RE DISCCART   480000.00 2852500.00
RE DISCCART   475000.00 2854000.00
RE DISCCART   473500.00 2857000.00
RE DISCCART   473500.00 2860000.00
RE DISCCART   469000.00 2860000.00
RE DISCCART   464000.00 2860000.00
RE DISCCART   459500.00 2863200.00
RE DISCCART   454000.00 2863200.00
RE FINISHED

ME STARTING
ME INPUTFIL D:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844  1987          WEST-PALM-BCH
ME UAIRDATA  12844  1987          WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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CO STARTING
CO TITLEONE 1987 FPL MARTIN PROPOSED SIMPLE CYCLE CTS          2/7/00
CO TITLETWO PSD CLASS I SIGN. IMPACT ANALYSIS, EVERGLADES NP, GEN 10G/S, NAT GAS
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF   .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** MODELING ORIGIN IS 71.02 M EAST OF PROPOSED SOUTH CT STACK
** RECEPTOR GRID IS CENTERED ON MIDPOINT BETWEEN PROPOSED CT STACKS
**  BYPASS STACK LETTER CODE
** ------------------------
**  A -  BYPS 1
**  B -  BYPS 2
**          SRCID SRCTYP         XS          YS       ZS
**   UTM                         (m)         (m)      (m)
SO LOCATION  BASE35A  POINT     543100      2992900  0.0
SO LOCATION  BASE35B  POINT     543100      2992900  0.0

SO LOCATION  BASE59A  POINT     543100      2992900  0.0
SO LOCATION  BASE59B  POINT     543100      2992900  0.0

SO LOCATION  BASE95A  POINT     543100      2992900  0.0
SO LOCATION  BASE95B  POINT     543100      2992900  0.0

SO LOCATION  LD7535A  POINT     543100      2992900  0.0
SO LOCATION  LD7535B  POINT     543100      2992900  0.0

SO LOCATION  LD7559A  POINT     543100      2992900  0.0
SO LOCATION  LD7559B  POINT     543100      2992900  0.0

SO LOCATION  LD7595A  POINT     543100      2992900  0.0
SO LOCATION  LD7595B  POINT     543100      2992900  0.0

SO LOCATION  LD5035A  POINT     543100      2992900  0.0
SO LOCATION  LD5035B  POINT     543100      2992900  0.0

SO LOCATION  LD5059A  POINT     543100      2992900  0.0
SO LOCATION  LD5059B  POINT     543100      2992900  0.0

SO LOCATION  LD5095A  POINT     543100      2992900  0.0
SO LOCATION  LD5095B  POINT     543100      2992900  0.0

SO LOCATION  HPM35A   POINT     543100      2992900  0.0
SO LOCATION  HPM35B   POINT     543100      2992900  0.0

SO LOCATION  HPM59A   POINT     543100      2992900  0.0
SO LOCATION  HPM59B   POINT     543100      2992900  0.0

SO LOCATION  HPM95A   POINT     543100      2992900  0.0
SO LOCATION  HPM95B   POINT     543100      2992900  0.0

** Source Parameter Cards:
** POINT:   SRCID         QS      HS        TS        VS        DS
**                      (g/s)    (m)       (K)      (m/s)      (m)
SO SRCPARAM   BASE35A    5.0     18.3     863.7     36.48     6.71
SO SRCPARAM   BASE35B    5.0     18.3     863.7     36.48     6.71

SO SRCPARAM   BASE59A    5.0     18.3     875.4     35.45     6.71
SO SRCPARAM   BASE59B    5.0     18.3     875.4     35.45     6.71

SO SRCPARAM   BASE95A    5.0     18.3     890.4     33.38     6.71
SO SRCPARAM   BASE95B    5.0     18.3     890.4     33.38     6.71

SO SRCPARAM   LD7535A    5.0     18.3     878.7     29.84     6.71
SO SRCPARAM   LD7535B    5.0     18.3     878.7     29.84     6.71

SO SRCPARAM   LD7559A    5.0     18.3     888.2     29.32     6.71
SO SRCPARAM   LD7559B    5.0     18.3     888.2     29.32     6.71

SO SRCPARAM   LD7595A    5.0     18.3     905.4     28.07     6.71
SO SRCPARAM   LD7595B    5.0     18.3     905.4     28.07     6.71
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SO SRCPARAM    LD5035A     5.0    18.3     904.3     25.30     6.71
SO SRCPARAM    LD5035B     5.0    18.3     904.3     25.30     6.71

SO SRCPARAM    LD5059A     5.0    18.3     913.2     24.99     6.71
SO SRCPARAM    LD5059B     5.0    18.3     913.2     24.99     6.71

SO SRCPARAM    LD5095A     5.0    18.3     922.0     24.05     6.71
SO SRCPARAM    LD5095B     5.0    18.3     922.0     24.05     6.71

SO SRCPARAM    HPM35A      5.0    18.3     871.5     36.91     6.71
SO SRCPARAM    HPM35B      5.0    18.3     871.5     36.91     6.71

SO SRCPARAM    HPM59A      5.0    18.3     883.2     36.12     6.71
SO SRCPARAM    HPM59B      5.0    18.3     883.2     36.12     6.71

SO SRCPARAM    HPM95A      5.0    18.3     898.7     34.87     6.71
SO SRCPARAM    HPM95B      5.0    18.3     898.7     34.87     6.71

SO BUILDHGT BASE35A-BASE95A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35A-BASE95A      16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35A-BASE95A      16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT BASE35A-BASE95A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35A-BASE95A      16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT BASE35A-BASE95A       6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35A-BASE95A       0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35A-BASE95A      15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID BASE35A-BASE95A      15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID BASE35A-BASE95A       0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35A-BASE95A      15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID BASE35A-BASE95A      14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT LD5035A-LD7595A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035A-LD7595A      16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035A-LD7595A      16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT LD5035A-LD7595A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035A-LD7595A      16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT LD5035A-LD7595A       6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035A-LD7595A       0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035A-LD7595A      15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID LD5035A-LD7595A      15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID LD5035A-LD7595A       0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035A-LD7595A      15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID LD5035A-LD7595A      14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT BASE35B-BASE95B       0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35B-BASE95B      16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT BASE35B-BASE95B       6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT BASE35B-BASE95B       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT BASE35B-BASE95B      16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT BASE35B-BASE95B       6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35B-BASE95B       0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID BASE35B-BASE95B      15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID BASE35B-BASE95B      14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID BASE35B-BASE95B       0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID BASE35B-BASE95B      15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID BASE35B-BASE95B      14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT LD5035B-LD7595B       0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035B-LD7595B      16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT LD5035B-LD7595B       6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT LD5035B-LD7595B       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT LD5035B-LD7595B      16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT LD5035B-LD7595B       6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035B-LD7595B       0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID LD5035B-LD7595B      15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID LD5035B-LD7595B      14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5035B-LD7595B       0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID LD5035B-LD7595B      15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID LD5035B-LD7595B      14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT HPM35A-HPM95A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT HPM35A-HPM95A      16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT HPM35A-HPM95A      16.76   16.76   16.76    0.00    0.00    0.00
SO BUILDHGT HPM35A-HPM95A       0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT HPM35A-HPM95A      16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT HPM35A-HPM95A       6.71    0.00    0.00    0.00    0.00    0.00
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SO BUILDWID HPM35A-HPM95A          0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID HPM35A-HPM95A         15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID HPM35A-HPM95A         15.13   14.07   12.59    0.00    0.00    0.00
SO BUILDWID HPM35A-HPM95A          0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID HPM35A-HPM95A         15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID HPM35A-HPM95A         14.06    0.00    0.00    0.00    0.00    0.00

SO BUILDHGT HPM35B-HPM95B          0.00    0.00   16.76   16.76   16.76    6.71
SO BUILDHGT HPM35B-HPM95B         16.76   16.76   16.76   16.76   16.76    6.71
SO BUILDHGT HPM35B-HPM95B          6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT HPM35B-HPM95B          0.00    0.00    0.00    0.00    6.71    6.71
SO BUILDHGT HPM35B-HPM95B         16.76    6.71    6.71    6.71   16.76    6.71
SO BUILDHGT HPM35B-HPM95B          6.71    0.00    0.00    0.00    0.00    0.00
SO BUILDWID HPM35B-HPM95B          0.00    0.00   12.59   14.07   15.13   13.41
SO BUILDWID HPM35B-HPM95B         15.58   15.47   14.63   15.47   15.58   13.41
SO BUILDWID HPM35B-HPM95B         14.06    0.00    0.00    0.00    0.00    0.00
SO BUILDWID HPM35B-HPM95B          0.00    0.00    0.00    0.00   14.06   13.41
SO BUILDWID HPM35B-HPM95B         15.58   10.91    9.14   10.91   15.58   13.41
SO BUILDWID HPM35B-HPM95B         14.06    0.00    0.00    0.00    0.00    0.00

SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE35 BASE35A BASE35B
SO SRCGROUP BASE59 BASE59A BASE59B
SO SRCGROUP BASE95 BASE95A BASE95B
SO SRCGROUP LD7535 LD7535A LD7535B
SO SRCGROUP LD7559 LD7559A LD7559B
SO SRCGROUP LD7595 LD7595A LD7595B
SO SRCGROUP LD5035 LD5035A LD5035B
SO SRCGROUP LD5059 LD5059A LD5059B
SO SRCGROUP LD5095 LD5095A LD5095B
SO SRCGROUP HPM35 HPM35A HPM35B
SO SRCGROUP HPM59 HPM59A HPM59B
SO SRCGROUP HPM95 HPM95A HPM95B
SO FINISHED

RE STARTING
RE DISCCART   557000.00 2789000.00
RE DISCCART   556600.00 2792000.00
RE DISCCART   556000.00 2796000.00
RE DISCCART   553000.00 2796500.00
RE DISCCART   548000.00 2796500.00
RE DISCCART   542700.00 2796500.00
RE DISCCART   542700.00 2800000.00
RE DISCCART   542700.00 2805000.00
RE DISCCART   542700.00 2810000.00
RE DISCCART   542000.00 2811000.00
RE DISCCART   541300.00 2814000.00
RE DISCCART   542700.00 2816000.00
RE DISCCART   544100.00 2820000.00
RE DISCCART   543500.00 2824600.00
RE DISCCART   545000.00 2829000.00
RE DISCCART   545700.00 2832200.00
RE DISCCART   546200.00 2835700.00
RE DISCCART   548600.00 2837500.00
RE DISCCART   550300.00 2839000.00
RE DISCCART   545000.00 2839000.00
RE DISCCART   540000.00 2839000.00
RE DISCCART   550500.00 2844000.00
RE DISCCART   545000.00 2844000.00
RE DISCCART   540000.00 2844000.00
RE DISCCART   550300.00 2848600.00
RE DISCCART   545000.00 2848600.00
RE DISCCART   540000.00 2848600.00
RE DISCCART   535000.00 2848600.00
RE DISCCART   530000.00 2848600.00
RE DISCCART   525000.00 2848600.00
RE DISCCART   520000.00 2848600.00
RE DISCCART   514500.00 2848600.00
RE DISCCART   514500.00 2843000.00
RE DISCCART   514500.00 2838000.00
RE DISCCART   514500.00 2832500.00
RE DISCCART   510000.00 2832500.00
RE DISCCART   505000.00 2832500.00
RE DISCCART   500000.00 2832500.00
RE DISCCART   495000.00 2832500.00
RE DISCCART   494500.00 2837000.00
RE DISCCART   491500.00 2841000.00
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RE DISCCART   488500.00 2845500.00
RE DISCCART   483000.00 2848500.00
RE DISCCART   480000.00 2852500.00
RE DISCCART   475000.00 2854000.00
RE DISCCART   473500.00 2857000.00
RE DISCCART   473500.00 2860000.00
RE DISCCART   469000.00 2860000.00
RE DISCCART   464000.00 2860000.00
RE DISCCART   459500.00 2863200.00
RE DISCCART   454000.00 2863200.00
RE FINISHED

ME STARTING
ME INPUTFIL D:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844  1987              WEST-PALM-BCH
ME UAIRDATA  12844  1987              WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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APPENDIX E

IWAQM PHASE II CALPUFF PARAMETER SETTINGS USED IN THE REGIONAL HAZE ANALYSIS

Table E-1. IWAQM Phase II Calpuff Parameter Settings Used in the Regional Haze Analysis
FPL Martin Two Proposed Simple-Cycle CTs

Number	Input Group Description	Variable	Seq	Description	Default Value	Modeled Value
1	Run Control	METRUN	1	Do we run all periods (1) or a subset (0)?	0	0
1		IBYR	2	Beginning year	User Defined	87
1		IBMO	3	Beginning month	User Defined	1
1		IBDY	4	Beginning day	User Defined	1
1		IBHR	5	Beginning hour	User Defined	1
1		IRLG	5	Length of run (hours)	User Defined	8760
1		NSPEC	5	Number of species modeled (for MESOPUFF II chemistry)	5	6
1		NSE	7	Number of species emitted	3	3
1		ITEST	8		2	2
1		MRESTART	9	Restart options (0 = no restart) allows splitting runs into smaller segments	0	0
1		NRESPD	10		0	0
1		METFM	11	Format of input meteorology (1 = CALMET, 2 = ISC)	1	2
1		AVET	12	Averaging time lateral dispersion parameters (minutes)	60	60
2	Tech Options	MGAUSS	1	Near-field vertical distribution (1 = Gaussian)	1	1
2		MCTADJ	2	Terrain adjustments to plume path (3 = Plume path)	3	3
2		MCTSG	3	Do we have subgrid hills? (0 = No) allows CTDM-like treatment for subgrid scale hills	0	0
2		MSLUG	4	Near-field puff treatment (0 = No slugs)	0	0
2		MTRANS	5	Model transitional plume rise? (1 = Yes)	1	1
2		MTIP	6	Treat stack tip downwash? (1 = Yes)	1	1
2		MSHEAR	7	Treat vertical wind shear? (0 = No)	0	1
2		MSPLIT	8	Allow puffs to split? (0 = No)	0	0
2		MCHEM	9	MESOPUFF-II Chemistry? (1 = Yes)	1	1
2		MWET	10	Model wet deposition? (1 = Yes)	1	1
2		MDRY	11	Model dry deposition? (1 = Yes)	1	1
2		MDISP	12	Method for dispersion coefficients (3 = PG & MP)	3	3
2		MTURBVW	13	Turbulence characterization? (Only if MDISP = 1 or 5)	3	0
2		MDISP2	14	Backup coefficients (Only if MDISP = 1 or 5)	3	4
2		MROUGH	15	Adjust PG for surface roughness? (0 = No)	0	0
2		MPARTL	16	Model partial plume penetration? (0 = No)	1	1
2		MTINV	17	Elevated inversion strength (0 = compute from data)	0	0
2		MPDF	18	Use PDF for convective dispersion? (0 = No)	0	0
2		MSGTIBL	19	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	0
2		MREG	20	Regulatory default checks? (1 = Yes)	1	0
3	Species List	CSPECn		Names of species modeled (for MESOPUFF II must be SO2-SO4-NOX-HNO3-NO3, PM10	User Defined	ALL 6
3		Specie Groups		Grouping of species if any	User Defined	NA
3		Specie Names		Manner species will be modeled	User Defined	
4	Grid Control	NX	1	Number of east-west grids of input meteorology	User Defined	2
4		NY	2	Number of north-south grids of input meteorology	User Defined	2
4		NZ	3	Number of vertical layers of input meteorology	User Defined	1
4		DGRIDKM	4	Meteorology grid spacing (km)	User Defined	224
4		ZFACE	5	Vertical cell face heights of input meteorology	User Defined	0.,5000.

Table E-1. IWAQM Phase II Calpuff Parameter Settings Used in the Regional Haze Analysis FPL Martin Two Proposed Simple-Cycle CTs						
Number	Input Group Description	Variable	Seq	Description	Default Value	Modeled Value
4		XORIGKM	6	Southwest comer (east-west) of input User	Defined meteorology	-224
4		YORIGIM	7	Southwest corner (north-south) of input User	Defined meteorology	-224
4		IUTMZN	8	UTM zone	User Defined	17
4		XLAT	9	Latitude of center of meteorology domain	User Defined	27.06
4		XLONG	10	Longitude of center of meteorology domain	User Defined	80.57
4		XTZ	11	Base time zone of input meteorology	User Defined	5
4		IBCOMP	12	Southwest X-index of computational domain	User Defined	1
4		JBCOMP	13	Southwest Y-index of computational domain	User Defined	1
4		IECOMP	14	Northeast X-index of computational domain	User Defined	2
4		JECOMP	15	Northeast Y-index of computational domain	User Defined	2
4		LSAMP	16	Use gridded receptors? (T = Yes)	F	F
4		IBSAMP	17	Southwest X-index of receptor grid	User Defined	0
4		JBSAMP	18	Southwest Y-index of receptor grid	User Defined	0
4		IESAMP	19	Northeast X-index of receptor grid	User Defined	0
4		JESAMP	20	Northeast Y-index of receptor grid	User Defined	0
4		MESHDN	21	Gridded recpetor spacing = DGRIDKM/MESHDN	1	1
5	Output Options	ICON	1	Output concentrations? (1 = Yes)	1	1
5		IDRY	2	Output dry deposition flux? (1 = Yes)	1	0
5		IWET	3	Output west deposition flux? (1 = Yes)	1	0
5		IVIS	4	Output RH for visibility calculations (1 = Yes)	1	0
5		LCOMPRS	5	Use compression option in output? (T = Yes)	T	T
5		ICPRT	6	Print concentrations? (0 = No)	0	1
5		IDPRT	7	Print dry deposition fluxes (0 = No)	0	0
5		IWPRT	8	Print wet deposition fluxes (0 = No)	0	0
5		ICFRQ	9	Concentration print interval (1 = hourly)	1	24
5		IDFRQ	10	Dry deposition flux print interval (1 = hourly)	1	1
5		IWFRQ	11	West deposition flux print interval (1 = hourly)	1	1
5		IPRTU	12	Print output units (1 = g/m**3; g/m**2/s; 3 = ug/m3, ug/m2/s)	1	3
5		IMESG	13	Status messages to screen? (1 = Yes)	1	1
5		LDEBUG	14	Turn on debug tracking? (F = No)	F	F
5		NPFDEB	15	(Number of puffs to track)	(1)	1
5		NN1	16	(Met. Period to start output)	(1)	1
5		NN2	17	(Met. Period to end output)	(10)	10
7	Dry Dep Chem	Dry Gas Dep		Chemical parameters of gaseous deposition species	User Defined	NOX,HNO3
						SO2
8	Dry Dep Size	Dry Part. Dep		Chemical parameters of particulate deposition species	User Defined	SO4,NO3
						PM10
9	Dry Dep Misc	RCUTR	1	Reference cuticle resistance (s/cm)	30	30
9		RGR	2	Reference ground resistance (s/cm)	10	10
9		REACTR	3	Reference reactivity	8	8
9		NINT	4	Number of particle-size intervals	9	9
9		IVEG	5	Vegetative state (1 = active and unstressed)	1	1

Table E-1. IWAQM Phase II Calpuff Parameter Settings Used in the Regional Haze Analysis						
	FPL Martin Two Proposed Simple-Cycle CTs					
Number	Input Group Description	Variable	Seq	Description	Default Value	Modeled Value
12		SL2PF	35	Maximum Sy/puff length	10	10
12		NSPLIT	36	Number of puffs when puffs split	3	3
12		IRESPLIT	37	Hours when puff are eligible to split	User Defined	HR 17=1
12		ZISPLIT	38	Previous hour's mixing height(minimum)(m)	100	100
12		ROLDMAX	39	Previous Max mix ht/current mix ht ratio must be less then this value for puff to split	0.25	0.25
12		EPSSLUG	40	Convergence criterion for slug sampling integration	1.00E-04	1.0E-04
12		EPSAREA	41	Convergence criterion for area source integration	1.00E-06	1.0E-06
13	Point Source	NPT1	1	Number of point sources	User Defined	1
13		IPTU	2	Units of emission rates (1 = g/s)	1	1
13		NSPT1	3	Number of point source-species combinations	0	0
13		NPT2	4	Number of point sources with fully variable emission rates	0	0
13		Point Sources		Point sources characteristics	User Defined	VAR
14	Area Source	Area Sources		Area sources characteristics	User Defined	NA
15	Volume Source	Volume		Volume sources characteristics	User Defined Sources	NA
16	Line Source	Line Sources		Buoyant lines source characteristics	User Defined	NA
17	Receptors	NREC		Number of user defined receptors	User Defined	180
17		Receptor Data		Location and elevation (MSL) of receptors	User Defined	VAR
Legend						
	DEPOS.	With Deposition				
	DEFAULT	Uses defaults				
	VAR	Variable Input				
	NA	Not Applicable				
	SAME	Same as recommended				

Table E-1. IWAQM Phase II Calpuff Parameter Settings Used in the Regional Haze Analysis						
	FPL Martin Two Proposed Simple-Cycle CTs					
Number	Input Group Description	Variable	Seq	Description	Default Value	Modeled Value
10	Wet Dep	Wet Dep		Wet deposition parameters	User Defined	Var
11	Chemistry	MOZ	1	Ozone background? (0 = constant background value; 1 = read from ozone.dat)	1	0
11		BCKO3	2	Ozone default (ppb) (Use only for missing data)	80	80
11		BCKNH3	3	Ammonia background (ppb)	10	10
11		RNITE1	4	Nighttime SO2 loss rate (%/hr)	0.2	0.2
11		RNITE2	5	Nighttime NOx loss rate (%/hr)	2	2
11		RNITE3	6	Nighttime HNO3 loss rate (%/hr)	2	2
12	Dispersion	SYTDEP	1	Horizontal size (m) to switch to time dependence	550	550
12		MHFTSZ	2	Use Heffter for vertical dispersion? (0 = No)	0	0
12		JSUP	3	PG Stability class above mixed layer	5	5
12		CONK1	4	Stable dispersion constant (Eq 2.7-3)	0.01	0.01
12		CONK2	5	Neutral dispersion constant (Eq 2.7-4)	0.1	0.1
12		TBD	6	Transition for downwash algorithms (0.5 = ISC)	0.5	0.5
12		IURB1	7	Beginning urban landuse type	10	10
12		IURB2	8	Ending urban landuse type	19	19
12		ILANDUIN	9	Land use type (20 = Unirrigated agricultural land)	(20)	20
12		ZOIN	10	Roughness length (m)	(0.25)	0.25
12		XLAIIN	11	Leaf area index	(3)	3
12		ELEVIN	12	Met. Station elevation (m above MSL)	(0)	0
12		XLATIN	13	Met. Station North latitude (degrees)	(-999)	-999
12		XLONIN	14	Met. Station West longitude (degrees)	(-999)	-999
12		ANEMHT	15	Anemometer height of ISC meteorological data (m)	(10)	10.1
12		ISIGMAV	16	Lateral turbulence (Not used with ISC meteorology)	(1)	NA
12		IMIXCTDM	17	Mixing heights (Not used with ISC meteorology)	(1)	NA
12		XMXLEN	18	Maximum slug length in units of DGRIDKM	1	1
12		XSAMLEN	19	Maximum puff travel distance per sampling step (units of DGRIDKM)	1	1
12		MXNEW	20	Maximum number of puffs per hour	99	99
12		MXSAM	21	Maximum sampling steps per hour	99	99
12		NCOUNT	22	Iterations when computing Transport Wind (Calmet & Profile Winds)	(2)	2
12		SYMIN	23	Minimum lateral dispersion of new puff (m)	1	1
12		SZMIN	24	Minimum vertical dispersion of new puff (m)	1	1
12		SVMIN	25	Array of minimum lateral turbulence (m/s)	6 * 0.50	6*0.50
12		SWMIN	26	Array of minimum vertical turbulence (m/s)	0.20,0.12,0.08,0.06,0.03,0.016	SAME
12		CDIV (1), (2)	27	Divergence criterion for dw/dz (1/s)	0.01 (0.0,0.0)	0.0,0.0
12		WSCALM	28	Minimum non-calm wind speed (m/s)	0.5	0.5
12		XMAXZI	29	Maximum mixing height (m)	3000	3000
12		XMINZI	30	Minimum mixing height (m)	50	50
12		WSCAT	31	Upper bounds 1st 5 wind speed classes (m/s)	1.54,3.09,5.14,8. 23,10.8	SAME
12		PLX0	32	Wind speed power-law exponents	0.07,0.07,0.10,0.15,0.35,0.55	SAME
12		PTGO	33	Potential temperature gradients PG E and F (deg/km)	0.020,0.035	SAME
12		PPC	34	Plume path coefficients (only if MCTADJ = 3)	0.5,0.5,0.5,0.5,0.35,0.35	SAME

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

June 6, 2001

Richard Piper, Licensing Manager
Environmental Services Department
Florida Power and Light Company
P.O. Box 14000
Juno Beach, FL 33408

Re: FPL Martin Plant
Air Permit No. PSD-FL-286
Martin Peaking Units 8A and 8B

Dear Mr. Piper:

I received your letter informing the Department that FPL does not intend to perform emissions testing on the Martin peaking units in either power augmentation mode or high temperature peaking mode. The site does not have steam capability to provide steam injection for power augmentation. In addition, operating the units in high temperature peaking mode is predicted to shorten the maintenance interval for the units. As I recall, each unit was restricted to 400 hours per year for power augmentation and 60 hours per year of high temperature peaking mode.

I agree that, without the required testing, FPL is not authorized to operate these units in either power augmentation mode or high temperature peaking mode. During submittal of the Title V permit revision to incorporate Units 8A and 8B, please request removal of the conditions associated with these methods of operation. Otherwise, you will need to include a Compliance Plan that outlines a proposed schedule for testing each unit and demonstrating compliance with the standards.

If you have any questions, please contact me at 850/921-9536.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner

New Source Review Section

cc: Al Linero
Scott Sheplak
Isidore Goldman, SED

FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

May 22, 2001

RECEIVED
MAY 29 2001
BUREAU OF AIR REGULATION

Mr. Jeff Koerner, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: FPL Martin Plant
PSD Permit #PSD-FL-286

Dear Mr. Koerner:

Per our discussion, this correspondence is to inform the Department that FPL does not at this time intend to perform emissions testing on the Martin peaking units 8A and 8B in either power augmentation mode or in high temperature peaking mode.

Currently, the site does not have excess steam capability with which to provide power augmentation capability. In addition, the operation of the new units in high temperature peaking mode is predicted to shorten the maintenance interval for the equipment.

FPL recognizes that we will be unable to operate in either of the two referenced operating modes unless and until the emissions testing is performed.

If you should have any questions, please do not hesitate to contact me at (561) 691-7058 or via email at rich_piper@fpl.com.

Very truly yours,

Richard Piper

Richard Piper
Licensing Manager
Florida Power & Light Company

cc:

Tom Tittle - DEP Southeast District Office

7001 0320 0001 3692 8376

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City, State, ZIP+4 Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions

July 3, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Florida Power and Light Company
Martin Power Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

Re: FPL Martin Power Plant, Units 8A and 8B
Extension of Air Construction Permit Expiration Date
Air Permit No. PSD-FL-286

Dear Mr. Lindsay:

In a letter dated June 28, 2002, Florida Power and Light Company (FPL) requested an extension of the expiration date for the above permit. The units have been constructed and are in operation. FPL requests additional time to complete the process of obtaining the Title V air operation permit. The Department approves this request.

The expiration date is hereby extended from **July 1, 2002** to **January 1, 2003** to provide the necessary time to obtain the Title V air operation permit. This permitting action does not authorize any new construction. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code (F.A.C.)

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this action will not be effective until further order of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/9/02 to the person(s) listed:

Mr. John M. Lindsay, FPL*
Mr. John Hampp, FPL
Mr. Buck Oven, PPSO
Mr. Tom Tittle, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson July 9, 2002
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

I signed for Howard as he is out of office —

TO: Howard Rhodes

THRU: Clair Fancy aaf for CHF
Al Linero aaf

FROM: Jeff Koerner JK

DATE: July 3, 2002

SUBJECT: FPL Martin Power Plant, Units 8A and 8B
Extension of Air Construction Permit Expiration Date
Air Permit No. PSD-FL-286

Attached for your approval and signature is a permit modification that extends the permit expiration date for the above referenced project. Day 74 is September 13, 2002. I recommend your approval and signature.

Attachments

CHF/AAL/jfk

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach,FL 33408

FPL

RECEIVED
JUL 02 2002
BUREAU OF AIR REGULATION

June 28, 2002

Clair Fancy
Bureau of Air Regulation
State of Florida
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Re:Martin Power Plant Construction Permit Extension Request, 0850001-008-AC:

Dear Clair,

Florida Power & Light Company is requesting an extension to the Construction Permit for the Simple Cycle CT's 8A and 8B. This request for the extension is to provide additional time to resolve operating conditions through simultaneous changes in the Martin Plant Construction and Title V Operating Permits. The Martin Combustion Turbines are GE Frame 7FA "Hot Nozzle" units which are not currently able to operate as designed under the current Construction and Operating Permits. Specifically the conditions for exempted excess emissions for these very low emitting units will not allow the units to operate fully as peaking units without exceeding permit limits during startup, shutdown, and oil to natural gas fuel switches.

The Martin Plant is providing additional test and operating data to the Department to assist in the development of acceptable permit conditions for the operation of Units 8A and 8B. Upon development of the new conditions for excess emissions, FPL will provide the required application for the simultaneous change in the permits.

Thanks for your assistance in this matter, and, if you should have any questions, please do not hesitate to contact me at (561) 691-2894.

Sincerely,

John Hampp
Senior Environmental Specialist
Florida Power and Light Company

7001 0320 0001 3692 8376

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City, State, ZIP+4 Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions

FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

May 22, 2001

RECEIVED

MAY 29 2001

BUREAU OF AIR REGULATION

Mr. Jeff Koerner, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: FPL Martin Plant
PSD Permit #PSD-FL-286

Dear Mr. Koerner:

Per our discussion, this correspondence is to inform the Department that FPL does not at this time intend to perform emissions testing on the Martin peaking units 8A and 8B in either power augmentation mode or in high temperature peaking mode.

Currently, the site does not have excess steam capability with which to provide power augmentation capability. In addition, the operation of the new units in high temperature peaking mode is predicted to shorten the maintenance interval for the equipment.

FPL recognizes that we will be unable to operate in either of the two referenced operating modes unless and until the emissions testing is performed.

If you should have any questions, please do not hesitate to contact me at (561) 691-7058 or via email at rich_piper@fpl.com.

Very truly yours,

Richard Piper

Richard Piper
Licensing Manager
Florida Power & Light Company

cc:

Tom Tittle - DEP Southeast District Office

Florida Power & Light Company, P. O. Box 14000, Juno Beach, FL 33408-0420

FPL

RECEIVED
MAY 21 2001
BUREAU OF AIR REGULATION

May 17, 2001

Clair Fancy, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

PSD-FL-286

Re: Initial Startup "First Fire" of Martin Plant
Simple Cycle Combustion Turbine Unit PMR8B

Dear Clair:

This correspondence is to serve as notification to the Department, in accordance with 40 CFR 60.7(a)(3), that Florida Power & Light Company first fired Martin Plant Simple Cycle Combustion Turbine Unit PMR8B on May 16, 2001.

Please feel free to contact me at (561) 691-2438, if you have any questions.

Very truly yours,

Mary Kay For Dave Knutson

David W. Knutson
Designated Representative
Florida Power & Light Company

cc:

Tom Tittle	FDEP Southeast District Office
Lynn Haynes	EPA Region 4
Joseph Kahn	FDEP Bureau of Air Resource Management
File	

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

FPL

RECEIVED

AUG 14 2000

BUREAU OF AIR REGULATION

August 10, 2000

Mr. Al Linero, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Notification of Construction Start
FPL Martin Peaking Unit Project

Dear Mr. Linero:

Pursuant to the requirements of 40 CFR 60.7(a)(1), please note that the Martin Peaking Unit construction project is scheduled to commence construction on or about August 14th, 2000.

Thank you and your staff for your assistance with permitting this project. I look forward to working with you in the future.

Very truly yours,

Richard Piper

Richard Piper
Licensing Manager
Florida Power & Light Company

cc: G. Kaumer
B. Oven
L. Goldman
EPA
NPS

Memorandum

Florida Department of Environmental Protection

TO:	Howard L. Rhodes
THRU:	Clair Fancy Al Linero
FROM:	Jeff Koerner
DATE:	July 19, 2000
SUBJECT:	Project No. 0850001-008-AC (PSD Permit No. PSD-FL-286) FPL Martin Power Plant Addition of Two 170 MW Simple Cycle Combustion Turbines

I signed Howard out

The Final Permit is attached for your approval and signature for a project that will add 340 MW of electric power to the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The permit authorizes the installation of two simple cycle 170 MW General Electric Model PG7241(FA) combustion turbines with electrical generator sets, two gas fired fuel heaters, and a distillate oil storage tank. The primary fuel is pipeline-quality natural gas with very low sulfur distillate oil as a backup fuel. The permit limits fuel consumption to an equivalent of 3390 hours per year of which no more than 500 hours per year may be gas firing. The Department determined dry low-NOx combustion technology to represent the Best Available Control Technology (BACT) for emissions of nitrogen oxides. For CO, PM/PM_{10}, and SO_2 emissions, BACT is the efficient combustion of clean fuels.

The Public Notice of Intent to Issue was published in the Stuart News on June 13, 2000. The Department received the proof of publication on June 19, 2000. No comments were received from the public, the Southeast District Office, or National Park Service regarding the Draft Permit. EPA Region 4 provided minor written comments prior to the publication date. The applicant provided additional information regarding emissions of hazardous air pollutants. A brief description of the comments and the Department's responses are summarized in the attached Final Determination.

I recommend your approval and signature. Day 90 is September 8, 2000.

Attachments

CHF/AAL/jfk

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911
Expires:	July 1, 2002

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality. The permit authorizes installation at the existing power plant of two simple cycle, 170 MW combustion turbines with electrical generator sets fired primarily with natural gas.

The project will be constructed at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46".

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

APPENDICES

The following Appendices are attached as part of this permit.

- Appendix A - Terminology
- Appendix BD - Department's BACT Determinations
- Appendix E - Emissions Standards Summary
- Appendix GC - Construction Permit General Conditions
- Appendix GG - NSPS Subpart GG Requirements for Gas Turbines
- Appendix XS - CEMS Excess Emissions Report

HR
Howard L. Rhodes, Director
Division of Air Resources Management

Date: 7/21/00

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1. Article Addressed to:

Mr. John M. Lindsay
Plant General Mgr.
FPL - Martin Plant
P. O. Box 176
Indiantown, FL 34956

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 7-27-00

C. Signature

X Michael Spahr ☐ Agent ☐ Addressee

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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

Permit No. PSD-FL-286
Project No. 0850001-008-AC
Two New 170 MW Combustion Turbines
FPL Martin Power Plant
Martin County, Florida

Enclosed is Final Permit No. PSD-FL-286 for Project No. 0850001-008-AC. This permit authorizes FPL to construct two new 170 MW combustion turbines at FPL's Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. As noted in the Final Determination (attached), the Department made only minor changes to the Final Permit. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/24/00 to the persons listed:

Mr. John M. Lindsay, FPL*
Mr. Richard G. Piper, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 7/24/00
(Clerk) (Date)

The Department distributed a public notice package on June 9, 2000 for a project that will add 340 MW of electric power generating capacity to the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The applicant, Florida Power and Light, proposes to install two simple cycle, 170 MW General Electric Model PG7241(FA) simple cycle combustion turbines with electrical generator sets. The Public Notice of Intent to Issue was published in the Stuart News on June 13, 2000. The Department received the proof of publication on June 19, 2000.

COMMENTS FROM THE PUBLIC, DISTRICT OFFICE, AND NPS

The Department received no comments from the public, the Department's Southeast District Office, or the National Park Service during the comment period.

COMMENTS FROM THE APPLICANT

On June 6, 2000, the Department received comments from the applicant in response to an earlier question regarding emissions of hazardous air pollutants, particularly formaldehyde. The applicant explained that the emission factor used in the initial application was based on a report from EPRI and was believed to be the most technically accurate for estimating HAP emissions from large utility combustion turbines. The applicant suggests that large combustion turbines are not appropriately represented in the newly finalized AP-42 emission factors. However, calculation of the potential HAP emissions based on the emission factor for operation greater than 80% of base load indicates that this project is not a major source of HAP emissions, in and of itself. The Department's separate analysis confirms this conclusion. The Department estimates potential emissions of 4.5 tons of formaldehyde per year and 7.4 tons of combined HAPs per year.

COMMENTS FROM EPA REGION 4

On May 19, 2000, EPA Region 4 provided the following comments regarding the initial Draft Permit for this project.

1. EPA requested that the Department verify the potential emissions estimate for formaldehyde.

   Response: The applicant responded as indicated above and the Department confirmed that this project is expected to be minor with respect to HAP emissions.

2. EPA stated that it has a policy regarding automatic exemptions for excess emissions due to startup and shutdown. BACT should apply during all normal operations of the equipment. Also, the permit condition allowing excess emissions is unclear regarding the exclusion of "two hourly averages" from the CEMS data.

   Response: The Department reviewed the operational design of the General Electric Model PG7241(FA) gas turbine. To achieve the lean, premix steady state operation resulting in single digit NOx emissions, the automated gas turbine control system stages the air and fuel mixtures in various combinations of combustors. For startup, this may result in higher pollutant concentrations for approximately 30 minutes, but might not result in higher mass emission rates because less fuel is typically fired during these periods. Shutdown generally lasts less than 20 minutes and may or may not result in higher emissions. Many control systems require a period of time to reach appropriate temperatures or other parameters before emission reductions can be guaranteed. The Department believes the permit condition is reasonable because of the short period of excess emissions allowed and because it is in the permittee's best interest to achieve steady state operation as soon as possible. In addition, the Department's rules provide this authority as approved by EPA in the State Implementation Plan. The condition has been revised to clarify the exclusion of CEM emissions data from the compliance determination.

3. EPA commented that the Department's revised cost analysis better reflected the true costs of installing a selective catalytic reduction system and an oxidation catalyst system.

   Response: No response necessary.

   In June, EPA Region 4 also provide verbal comments that a few other states were requiring initial performance tests for formaldehyde and other HAP emissions.

   Response: The Department notes this comment and may consider it for future projects.

CONCLUSION

The final action of the Department is to issue the final permit with the changes mentioned above and to correct minor typographical errors.

FACILITY DESCRIPTION

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's and are fired with low sulfur residual oil and natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	Emission Unit Description
011	Simple Cycle Unit No. 8A: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
012	Simple Cycle Unit No. 8B: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 8A and 8B.

REGULATORY CLASSIFICATION

HAPs: Based on the Title V permit, the existing facility is a major source of hazardous air pollutants (Title III). This project is not, in and of itself, major for HAPs.

Acid Rain: The existing facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: The existing facility is a Title V major source of air pollution because potential emissions of at least one pollutant such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceed 100 tons per year.

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, each new project requires a PSD applicability review. For each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C., a determination of Best Available Control Technology (BACT) is required. For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: Emissions units are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 02/19/00 and all related correspondence.
- Initial Draft Permit issued on May 5, 2000 and subsequent correspondence regarding revisions.

The following conditions apply to all emissions units and activities defined for this project.

GENERAL REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, 400 North Congress Avenue, P.O. Box 15425, West Palm Beach, Florida 33416-5425. The phone number is 561/681-6600 and the fax number is 561/681-6755.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.

4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for routine operation of the permitted emissions units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Applicable Test Procedures

    (a) *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)1. and 2., F.A.C.]

(b) *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

(c) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

20. Determination of Process Variables

(a) *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

21. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS

22. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

REPORTS

23. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

24. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

COMBUSTION TURBINES

This section of the permit addresses the following new emissions units.

EU ID No.	Common Emission Unit Description
011 012	Simple Cycle Units Nos. 8A and 8B: Each unit consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 80 feet tall and 20.5 feet in diameter, and associated support equipment. Natural gas is the primary fuel with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10}, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. The capacities by fuel and method of operation are: *Natural Gas* • Normal Firing: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,461,000 acfm at 1095° F. • Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,380,000 acfm at 1115° F. • Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,488,000 acfm at 1110° F. *Distillate Oil*: At a compressor inlet air temperature of 35° F and firing 2000 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW. The water injection rate for NOx control will be approximately 131,000 pounds per hour. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,539,000 acfm at 1075° F. Note: All heat input values are based on the higher heating values (HHV) of the fuels.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}) and sulfur dioxide (SO_2): [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (a) *Subpart A, General Provisions*, incuding:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

(b) *Subpart GG, Standards of Performance for Stationary Gas Turbines* are identified in *Appendix GG* of this permit. These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

PERFORMANCE RESTRICTIONS

3. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines with electrical generator sets, each designed to produce a nominal 170 MW of electrical power. [Applicant Request; Design]

4. Permitted Capacity: The heat input rates (HHV) to each combustion turbine shall not exceed the following:

   (a) *Normal Gas Firing*: 1860 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 182 MW.

   (b) *Gas Firing With Power Augmentation (Steam Injection)*: 1800 mmBTU per hour of natural gas with a compressor inlet air temperature of 59° F and producing a maximum 180 MW.

   (c) *Gas Firing With Peaking*: 1920 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 190 MW.

   (d) *Distillate Oil Firing*: 2008 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 191 MW.

   The heat input rates are based on the higher heating values (HHV) of 23,127 BTU/lbm for natural gas and 19,490 BTU/lbm for distillate oil. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

5. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

6. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by this permit. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in this permit. [Application; Rule 62-210.200(PTE), F.A.C.]

7. Alternate Gas Firing Methods of Operation

   (a) *Power Augmentation Mode*: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 400 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Power augmentation when firing distillate oil is prohibited.

   (b) *High Temperature Peaking Mode*: In accordance with the manufacturer's recommendations, each combustion turbine may be operated in a high temperature peaking mode when firing natural gas to provide additional power during periods of peak electrical power demands. Peaking is achieved through the automated gas turbine control system by allowing slightly higher exhaust temperatures, calculating a new combustion reference temperature for the peak load, and adjusting the fuel distribution between the fuel nozzles to maintain lean pre-mix firing. During the transfer from base load to peak load and during peak load operation, each unit will remain in the lean pre-mix steady state mode. Each unit shall not exceed 60 hours of peaking during any consecutive 12 months. To qualify as "peaking mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the peaking mode, the operator shall log the date, time, and new mode of operation. Peaking when firing distillate oil is prohibited.

   [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

8. Restricted Operation

   (a) *Gas Firing*: Each combustion turbine shall fire no more than 5,902,588,000 standard cubic feet of natural gas during any consecutive 12 months (equivalent to 3390 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° F).

   (b) *Oil Firing*: Each combustion turbine shall fire no more than 7,358,350 gallons of distillate oil during any consecutive 12 months (equivalent to 500 hours per year at the maximum firing rate for a compressor inlet temperature of 59° F). If oil is fired, the natural gas consumption limit shall be reduced by 127.4 standard cubic feet of gas for every gallon of distillate oil fired.

   The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each method of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

9. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS CONTROLS

10. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion

process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, exhaust temperatures, heat input, and fully automated startup and shutdown. [Design; 62-212.400(BACT), F.A.C.]

11. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine . [Design; Rule 62-212.400(BACT), F.A.C.]

12. Tuning: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. The permittee shall provide at least 5 days advance notice prior to any tuning session. [Design; Rule 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix E of this permit.}

13. Carbon Monoxide (CO)

(a) *Gas Firing, Normal and Peaking*: When firing natural gas under normal operating conditions and in the high temperature peaking mode, CO emissions from each combustion turbine shall not exceed 32.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load.

(c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

14. Nitrogen Oxides (NOx)

(a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(c) *Gas Firing With Peaking*: When firing natural gas with high temperature peaking, NOx emissions from each combustion turbine shall not exceed 105.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(d) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332]

15. Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2)

(a) *Particulate Matter*: When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load.

(b) *Fuel Specifications*. Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

(c) *VE Standard*. When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

16. Volatile Organic Compounds (VOC)

(a) *Gas Firing*: When firing natural gas under any method of operation, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

(b) *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such

emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

18. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

    (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

    (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

    (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

    (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    (e) If the permittee provides at least 5 days advance notice prior to tuning in accordance with the manufacturer's recommendations, up to three 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each gas turbine due to excess NOx emissions resulting from tuning. *{Permitting Note: It is expected that no more than two tuning sessions would occur each year.}*

    [Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR 60.40a(b)]

20. Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C.

    (a) EPA Method 5 or 17 - Determination of Particulate Matter Emissions from Stationary Sources

    (b) EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources

    (c) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources

    (d) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources

    (e) EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

    (f) EPA Methods 25 or 25A - Determination of Volatile Organic Concentrations *{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.}*

    No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [40 CFR 60, Appendix A; Rule 62-204.800, F.A.C.]

21. Initial Tests Required: Initial performance tests to demonstrate compliance with each emission standard for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup distillate oil firing shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of each emissions unit. Initial performance tests shall be conducted for CO, NOx, PM, VOC and visible emissions. Tests for CO, NOx, and VOC shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. NOx performance tests shall be conducted in accordance with the requirements of 40 CFR 60, Subpart GG. For the initial performance tests, emissions data shall be presented in units of the BACT standards as well as the units specified in the Subpart GG emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

22. Annual Performance Tests: Annual performance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup distillate oil firing. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). CO and NOx performance tests shall be conducted concurrently. If conducted at permitted capacity, NOx emissions data collected during the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test.

    (a) For each combustion turbine that fires distillate oil for less than 200 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required.

    (b) For each combustion turbine that operates with power augmentation for less than 200 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.

    [Rule 62-297.310(7)(a)4., F.A.C.]

23. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for each combustion turbine to demonstrate compliance with the CO, NOx, PM, VOC and visible emissions standards for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup oil firing. Tests for CO, NOx, and VOC emissions shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. All tests shall be conducted within the 12 months prior to renewing the air operation permit. [Rule 62-297.310(7)(a)3., F.A.C.]

24. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment, including the replacement of dry low-NOx combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine. This does not apply to routine maintenance. [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

25. Combustion Turbine Testing Capacity

    (a) Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines.

    (b) Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity for each method of operation. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.

(c) For performance tests conducted when gas firing under the power augmentation mode and under the high temperature peaking mode, the permittee shall document that the combustion turbine was operating under "peak load" for the given ambient conditions. For power augmentation, the steam injection rate shall be no less than 100,000 pounds of steam per hour.

[Rule 62-297.310(2), F.A.C.; 40 CFR 60.335]

CONTINUOUS MONITORING REQUIREMENTS

26. NOx CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack to meet the requirements of the Acid Rain program and to demonstrate compliance with the NOx standards specified in this permit. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NOx monitoring devices shall comply with the certification requirements, quality assurance procedures, and all other provisions of the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of the following information: CEM equipment specifications, manufacturer, model, type, calibration and maintenance needs, and the proposed location.

(a) *Installation.* Each CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 75.62.

(b) *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Each valid 1-hour average shall be calculated using at least two valid data points at least 15 minutes apart.

(c) *Data Reporting.* Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 3-hour average. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of three valid 1-hour emission rates. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. Notification shall include either a written letter, a phone call, or a fax transmittal to the Compliance Authority. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required by this permit.

(d) *Data Exclusion for Compliance.* Unless prohibited by Rule 62-210.700(4), F.A.C., valid 1-hour monitoring averages shall not include periods of excess emissions due to startup, shutdown, documented malfunction, or the result of tuning as described and limited under Specific Condition 18 of this permit. Because such data may be excluded, the 3-hour average to determine compliance need not consist of *consecutive* 1-hour averages.

(e) *Alternate Methods of Operation.* Each 1-hour monitoring average consisting of any data collected during an alternate method of operation (oil firing, power augmentation, or peaking) shall be attributed entirely to the alternate method of operation. For each 3-hour average consisting of more than one method of operation, compliance shall be determined by prorating each emission standard based on the number of 1-hour averages represented. In event of a CEMS malfunction or occurrence of excess emissions while operating in the power augmentation or peaking modes, the permittee shall immediately cease power augmentation or peaking and revert to normal gas firing or shut down the combustion turbine.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-212.400(BACT), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

RECORDS

27. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

(a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan), natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance with the monitoring requirements of 40 CFR 60, Subpart GG.

(a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

(c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2), provided:

(1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

(2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

(3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d). [40 CFR 60, Subpart GG; Applicant Request]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of each mode of operation and the fuel consumption for each combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three (3) days of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

30. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, periods of startup, shutdown and malfunction shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. Within 30 days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

This section of the permit addresses the following new emissions units.

EU ID No.	Emission Unit Description
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 8A and 8B.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE RESTRICTIONS

3. Equipment: The permittee is authorized to install, operate, and maintain the following emissions units and supporting equipment: two gas fuel heaters fired solely with natural gas (23.71 mmBTU per hour) designed to heat the natural gas supplied to simple cycle combustion turbines 8A and 8B; and one 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to simple cycle combustion turbines 8A and 8B. [Applicant Request]

4. Hours of Operation: The hours of operation for the gas fuel heaters and distillate oil storage tank are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Good Combustion: Visible emissions of 5% opacity or less from the gas fuel heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

RECORDS

6. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual amount of natural gas fired in the gas fuel heaters and the annual throughput of distillate oil for the storage tank . [Rule 62-210.370(3), F.A.C.]

7. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

°F	- Degrees Fahrenheit
DEP	- State of Florida, Department of Environmental Protection
DARM	- Division of Air Resource Management
EPA	- United States Environmental Protection Agency
F.A.C.	- Florida Administrative Code
F.S.	- Florida Statute
SOA	- Specific Operating Agreement
UTM	- Universal Transverse Mercator
CT	- Combustion Turbine
HRSG	- Heat Recovery Steam Generator
DLN	- Dry Low-NOx Combustion Technology
SCR	- Selective Catalytic Reduction
OC	- Oxidation Catalyst Technology for CO Control

RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example:	[Rule 62-213.205, F.A.C.]	
Where:	62	- identifies the specific Title of the F.A.C.
	62-213	- identifies the specific Chapter of the F.A.C.
	62-213.205	- identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example:	Facility ID No. 099-0001	
Where:	099	- identifies the specific county location
	0221	- identifies the specific facility

New Permit Numbers:

Example:	Permit No. 099-2222-001-AC or 099-2222-001-AV	
Where:	AC	- identifies the permit as an Air Construction Permit
	AV	- identifies the permit as a Title V Major Source Air Operation Permit
	099	- identifies the specific county that project is located in
	2222	- identifies the specific facility
	001	- identifies the specific permit project

Old Permit Numbers:

Example:	Permit No. AC50-123456 or AO50-123456	
Where:	AC	- identifies the permit as an Air Construction Permit
	AO	- identifies the permit as an Air Operation Permit
	123456	- identifies the specific permit project

FPL MARTIN POWER PLANT - MARTIN COUNTY
Project No. 0850001-008-AC (PSD-FL-286)
New EUs 011 - 014: Addition of Two New Simple-Cycle Gas Turbines

1.0 EXISTING FACILITY

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

2.0 PROJECT DESCRIPTION

The applicant, Florida Power and Light, proposes to install two new simple cycle combustion turbines, two gas-fired natural gas fuel heaters, a common distillate oil storage tank, and associated equipment at the existing FPL Martin Power Plant. Each combustion turbine consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 60 feet tall and 22 feet in diameter. Each unit is designed to produce a nominal 170 MW of electrical power fired with natural gas as the primary fuel and low sulfur distillate oil as a backup fuel. The applicant proposes to limit use of the gas turbines as "peaking units" by restricting the allowable operation to no more than 3390 hours per year per unit. Of this total, no more than 500 hours per year would occur when firing low sulfur distillate oil as a backup fuel. In addition, the applicant requests approval for "power augmentation" and "peaking" as authorized high power modes of operation when firing natural gas. The high power modes result in higher CO and NOx emissions than those for normal gas firing and are discussed in more detail under the NOx BACT Determination. Of the allowable 3390 hours per year, no more than 500 hours per year would occur when operating in the high power modes. The applicant proposes dry low-NOx (DLN) combustion technology to control nitrogen oxide emissions and combustion design with clean fuels to minimize emissions of other pollutants.

As a result of fuel combustion, this project will emit emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of CO, NOx, PM/PM_{10}, and SO_2 exceed the Significant Emissions Rates established in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, the Department must establish emissions standards that represent a determination of Best Available Control Technology (BACT) for these pollutants. The permit will also include emissions standards for VOC as a PSD-synthetic minor pollutant. This document presents a detailed description of the PSD applicability analysis and BACT determination. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanied the Department's Intent to Issue Permit package.

An initial Intent to Issue Permit package was mailed to the applicant on May 5, 2000. The applicant requested several changes and provided additional supporting information. The primary changes were the addition of high temperature peaking for 60 hours per year, a reduction of power augmentation to 400 hours per year, revised stack dimensions, NOx compliance demonstrated with Acid Rain CEMS data, fuel consumption limits equivalent to hours of operation limits, addition of a particulate matter limit with testing, a visible emissions limit of 10% opacity for both gas and oil firing, and minor revisions to the maximum heat input and power output based on General Electric data. Revisions of the BACT determination are noted with the revision date.

3.0 PSD APPLICABILITY REVIEW

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program as approved by the EPA and defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with a National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. An existing facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and it falls under one of the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C.

The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because potential emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. For new projects at PSD major sources, each pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant in accordance with Rule 62-212.400, F.A.C. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to implement BACT for several "significant" regulated pollutants.

This project will be located in Martin County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The following table summarizes the potential emissions increases and PSD applicability for this new project based on information provided by the applicant.

Pollutant	Project Potential Emissions[a] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	Subject To BACT?
CO	170	100	Yes	Yes
NOx	423	40	Yes	Yes
PM	38	25	Yes	Yes
PM_{10}	38	15	Yes	Yes
SAM	5	7	No	No
SO_2	64	40	Yes	Yes
VOC	13	40	No	No

[a] - For each gas turbine, potential emissions were estimated by the applicant based on 2390 hours per year of normal gas firing, 500 hours per year of gas firing with high power mode, and 500 hours per year of distillate oil firing as a backup fuel. Potential emissions also include emissions from two gas fuel heaters and a distillate oil tank.

Therefore, the proposed combustion turbine project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM/PM_{10}, and SO_2.

4.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination and shall also give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants). The combustion turbine project is subject to 40 CFR 60, Subpart GG, a New Source Performance Standards (NSPS) which regulates Stationary Gas Turbines, adopted by reference in Rule 62-204.800, F.A.C. There are no applicable NESHAP regulations.

The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

5.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

For this project, the following pollutants are subject to a BACT determination: CO, NOx, PM/PM_{10}, and SO_2. The applicant proposed control strategies for these pollutants in the PSD permit application. Besides the information submitted by the applicant, the Department also relied on the following information:

- The National Park Service made no adverse comments on the application;
- EPA Region 4 provided comments on the initial Draft Permit on May 19, 2000;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical product literature regarding DLN emissions and the gas turbine control system;
- Englehard equipment cost quotes for a CO oxidation catalyst and selective catalytic NOx reduction;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- Proposed AP-42 changes to Section 3.1 for gas turbines (10/96 draft and 5/98 revision);
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;
- Goal Line Environmental Technology Website: http://www.glet.com; and
- Catalytica Website – www.catalytica-inc.com

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. The following table provides a summary of the most recent determinations similar projects in the United States.

Brief Summary of Recent CO, NOx, and PM BACT Determinations for Similar Simple Cycle, Gas Fired Units

Project Location	Unit MW	Date	Technology	CO Limit ppmvd @ 15% O2	NOx Limit Ppmvd @ 15% O2	PM Limit	Comments
FPL Martin Plant, FL	170	04/00, D	DLN	9 15 w/PA	10, 3-hr CEMS 12 w/PA, 3-hr CEMS	5% Opacity	500 hr/yr oil firing 500 hr/yr PA mode
Palmetto Power, FL	170 MW WH 501FD	03/00, D	DLN	Initial: 25 (12 months) Final: 15	15, 3-hr CEMS	10% opacity	No oil firing
Desoto Power, FL	170 MW GE 7FA	03/00, D	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Shady Hills Pasco, FL	170 MW GE 7FA	01/00, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Vandolah Hardee, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Oleander Brevard, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
JEA Baldwin, FL	170 MW GE 7FA	10/99, P	DLN	12	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Reliant Osceola, FL	170 MW GE 7FA	11/99, P	DLN	10.5	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
TEC Polk Power, FL	165 MW GE 7FA	10/99, P	DLN	15	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Dynegy Heard, GA	170 MW WH 501F	10/99, P	DLN	25	15	10% opacity	No oil firing
Tenaska Heard, GA	170 MW GE 7FA	12/98, P	DLN	15	15	Unknown	720 hr/yr oil firing
Calvert City, KY	170 MW GE 7FA	1999, D	WI	30, base load 90, other	25	Unknown	? hr/yr oil firing
Mid-GA Cogen	119 MW WH 501D5A	06/98, O	DLN, SCR	10	9	18 lb/hr	? hr/yr oil firing
Dynegy Reidsville, NC	180 MW WH 501F	06/99, P	DLN	25	Initial: 25 Final: 15 (by 2002)	6 lb/hr	1000 hr/yr oil firing
Lyondell Harris, TX	160 MW WH 501F	11/99, P	DLN	25	25	Unknown	No oil firing
Southern Energy, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
RockGen Cristiana, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
Lakeland, FL	250 MW WH 501G	07/98, P	DLN, HSCR	25	Initial: 25 Final: 9 (by 2002)	10% opacity	250 hr/yr oil firing

Abbreviations:

Manufacturer
GE – General Electric
WH – Westinghouse
ABB – Asea Brown Boyan

Date
D – Draft
O – Operating
P – Permitted

Controls
DLN – Dry Low-NOx
HSCR – Hot Selective Catalytic Reduction
SCR - Selective Catalytic Reduction
WI = Water or Steam Injection

Other
LAER – Lowest Achievable Emission Rate
CEMS – Continuous Emissions Monitoring System
PA – Power Augmentation (Steam Injection)

Notes: All data presented is for > 100 MW simple cycle units firing natural gas. The Lakeland project is permitted for combined cycle operation with separate limits for simple cycle mode. The remaining projects are restricted to intermittent simple cycle operation.

5.1 NITROGEN OXIDES (NOx)

{Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NOx Emissions from Stationary Gas Turbines. Specific project information is included where applicable.}

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures associated with combustion turbines, the primary pollutant of concern is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @ 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions in the range of 150 ppmvd @ 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from stationary gas turbines is 75 ppmvd corrected to 15% oxygen and ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically-bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures due to the inherently lower thermal NOx portion. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Most new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to 100% of base load. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, usually less than 32° F.

<u>Identification of Control Technologies</u>

The following technologies were identified as potentially applicable for the control of NOx from combustion turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd @15% O_2.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the

same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for dry low-NOx combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%. DLN technology research for oil firing continues.

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850°F. SCR is a commercially available, demonstrated control technology currently employed on several combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd) with control efficiencies up to 98%.

"Hot" Selective Catalytic Reduction (SCR): Due to temperature limitations of conventional SCR catalysts, vendors have developed specially formulated catalysts designed to further the reduction reaction at temperatures up to 1025°F. Also, cooling air can be added to reduce the gas temperatures to the appropriate design range. Hot SCR can deliver NOx control efficiencies of 70% to 95%.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For boilers, SNCR has achieved control efficiencies in the 40% to 60% range.

Non-Selective Catalytic Reduction (NSCR): NSCR uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor in exhaust gas streams containing less than 3% oxygen. This technology has only been applied to automobiles and stationary reciprocating engines with variable control efficiencies.

SCONOx™: This technology is a NOx and CO control system offered by Goal Line Environmental Technologies and ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. The required operating

temperature range is between 300°F and 700°F which requires a HRSG for use with a gas turbine. SCONOx™ can achieve control efficiencies in the 90% to98% range.

XONON™: This is an emerging technology that partially burns fuel in a low temperature pre-combustor and completes combustion in a catalytic combustor.* The result is partial combustion with a lower temperature and NOx formation followed by flame-less catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but will be specific to each manufacturer and model of gas turbine. It is anticipated that control efficiencies will be in the 80% to 95% range.

<u>**Applicant's Proposed NOx Controls**</u>

For a simple cycle gas turbine, the applicant recognized "hot" selective catalytic reduction as the top control option followed by dry low-NOx (DLN) combustion technology and water injection. For this project, General Electric guaranteed NOx emissions of 9 ppmvd @ 15% oxygen with DLN technology for gas firing and 42 ppmvd @ 15% oxygen for oil firing with water injection. The applicant estimated that hot SCR could reduce these emissions rates to 4 ppmvd @ 15% oxygen for gas firing with DLN and 16 ppmvd @ 15% oxygen for oil firing with water injection. However, the applicant makes the following claims regarding additional adverse impacts.

Energy Impacts: Hot SCR would result in a pressure loss across the catalyst resulting in an energy penalty of approximately 0.5%. Significant energy costs are associated with operating the hot SCR system. The lost energy would be equivalent to 370,000 mmBTU per year or about 37 mmCF per year of natural gas.

Environmental Impacts: The maximum predicted NOx concentrations resulting from DLN technology are well below the PSD increment of 25 ug/m^3 (annual average), the AAQS of 100 ug/m^3 and less than 20% of the significant impact level. Additional NOx reduction from requiring hot SCR would not be significant. Hot SCR would generate additional emissions of ammonia (> 47.7 tons per year per unit) and ammonium sulfates (>6.6 tons per year per unit). Power lost to the hot SCR system would have to be generated by other less efficient units resulting in increased emissions. CO_2 emissions would greatly increase as a result of hot SCR. Spent catalyst may have to be handled and treated as hazardous wastes. Ammonia handling and storage involves inherent risks and safety issues.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of hot SCR would result in capital costs of $5,189,813 and annualized costs of $1,640,906 per year. The applicant assumed a hot SCR system would remove an additional 127 tons of NOx per year (4 ppmvd @ 15% O_2 and 61% control efficiency) over a DLN only system at 10.5 ppmvd @15% O_2. This resulted in an incremental cost effectiveness for hot SCR of $12,943 per ton of NOx removed.

The applicant rejected hot SCR primarily based on unreasonable costs associated with controlling the low available tonnage of NOx emissions available from this project. This is primarily due to the inherently low emissions of the General Electric Model PG7241(FA) gas turbine as well as the applicant's request to restrict operation to that of a peaking unit (3390 hours per year). Therefore, the applicant proposed the following NOx limit as BACT for this project:

<u>Applicant's Proposed NOx BACT</u>

Normal Gas Firing Mode: 10.5 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 42.0 ppmvd @ 15% O_2 achieved by water injection

The applicant concludes by stating that DLN combustion provides the most cost effective alternative, is pollution preventing, results in low ambient impacts, and is consistent with recent BACT determinations for similar simple cycle combustion turbines made by Florida and other states.

Department's NOx BACT Determination (Revised 06/06/00)

The Department rejected several previously mentioned control options for the following reasons.

- *Conventional Selective Catalytic Reduction (SCR)* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (850° F) for this technology.
- *Selective Non-Catalytic Reduction (SNCR)* was rejected because the gas turbine exhaust temperature of 1100°F is below the design limit (1600° F) for this technology.
- *Non-Selective Catalytic Reduction (NSCR)* was rejected because the oxygen content of the combustion turbine exhaust (13% to 15%) is above the design limit (3%) for this technology.
- *SCONOx™* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (700° F) for new technology.
- *XONON™* because this emerging technology is model-specific and not yet commercially available for the General Electric Model PG7241(FA).

The Department also recognizes hot selective catalytic reduction (hot SCR) combined with dry low-NOx (DLN) combustion technology as the top control option followed DLN technology alone, and water injection for oil firing. However, the Department disagrees with several of the applicant's statements regarding adverse impacts.

Energy Impacts: Installation of hot SCR *would* result in a total energy penalty of approximately 0.5% mostly due to the pressure drop across the catalyst bed. For SCR systems, EPA (1993) bases energy consumption to operate the SCR system on the pressure drop, neglecting other energy costs.

Environmental Impacts: The Department gives no consideration to the applicant's comment that there is no environmental benefit from add-on controls because NOx levels are already below the PSD increments, significant impact levels and AAQS. Ambient impacts from the project are only considered in the air quality analysis and carry no weight in making a BACT determination. Hot SCR would result in some ammonia "slip" or emissions of unreacted ammonia. However, estimating ammonia, ammonia sulfate, and PM_{10} emissions based on 9-10 ppm is misleading. Manufacturers of SCR systems typically design and guarantee systems with a 9 to 10 ppm of ammonia slip, but this is based on the end of the catalyst life and is not representative of actual emissions. An operator would attempt to reduce ammonia slip whenever possible to reduce operating costs. Storage and handling of ammonia does present additional risks, but these risks can be safely managed as evidenced by the numerous existing SCR systems, industrial ammonia refrigeration systems, fertilizer plants, etc.

Economic Impacts: In general, the Department agrees that adding hot SCR to the General Electric Model PG7241(FA) gas turbine with DLN controls would result in a cost effectiveness in the range of $10,000 to $13,000 per ton of NOx removed. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also recognizes that the analysis is significantly influenced by three critical constraints: the applicant's request for simple cycle operation only, the applicant's request for restricted operation as peaking units (3390 hours per year per gas turbine), and the inherently low emissions of the General Electric Model PG7241(FA) gas turbine. Should the applicant ever request operation of these gas turbines as base load units, conversion to combined cycle operation, or the substitution of a another gas turbine model, it is essential that the NOx BACT determination be reevaluated.

Based on the above discussion, the Department also rejects hot SCR as not cost effective for the project as limited by the applicant's requests. Therefore, the dry low-NOx combustion technology designed into the General Electric Model PG7241(FA) is determined to represent the best available control technology for this project. Dry low NOx combustion is pollution preventing in nature, avoids emissions of several non-regulated pollutants such as ammonia, and is consistent with recent BACT determinations made in Florida and other states.

The Department evaluated the applicant's request for two "high power modes" of operation when firing natural gas, which included steam injection for power augmentation and raising the combustion reference temperature for additional peaking power. The high power modes can result in NOx emissions that are higher than the normal gas-firing mode. Initially, the Department accepted the request for limited steam injection, but rejected the request for high temperature peaking primarily due to the high number of operating hours requested, and the potential for degradation of the unit. However, as part of the request for a revised Draft Permit, the applicant provided additional information from General Electric regarding the emissions performance and adjustments made by the automated gas turbine control system to achieve high temperature peaking. Also, the applicant reduced the request for peaking to 60 hours per year and power augmentation to 400 hours per year, which results in no increase in annual emissions. High temperature peaking is expected to result in lower CO and VOC emissions.

After consideration of the new information provided, the Department establishes the following NOx standards as BACT for this project:

NOx BACT Determination

Normal Gas Firing: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average (to ensure that the units remain tuned for maximum NOx reduction). NOx emissions shall also not exceed 10.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (The slightly higher continuous emissions limit with a short-term average was established to compensate for operation as a peaking unit. The mass emissions limit will be based on 10 ppmvd @15% O_2 and the most recent projects for the Model PG7241(FA) gas turbine.)

Gas Firing With Power Augmentation: 12.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the power augmentation mode to allow maximum power generation during the hot summer months of high demand. Operation in this mode will be restricted to no more than 400 hours per year.)

Gas Firing With Peaking: 15.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the peaking mode to provide limited short-term peaking power. Operation in this mode will be restricted to no more than 60 hours per year.)

Distillate Oil Firing: 42.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by water injection. (DLN combustion technology is ineffective when firing distillate oil as a backup fuel. Operation when oil firing with water injection will be restricted to no more than 500 hours per year.)

Corresponding mass emission limits will also be established for each method of operation. The Department will include specific conditions in the permit to address the following items:

- Each combustion turbine shall operate only in simple cycle mode. Conversion to combined cycle operation will require a permit modification.
- Each combustion turbine shall operate no more than 3390 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not fire oil for more than 500 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not operate in the power augmentation mode for more than 400 hours during any consecutive 12 months. Alternatively, the Department may establish equivalent amounts of fuel consumption limits based on the maximum heat inputs at a compressor inlet air temperature of 59° F, which was the basis of the potential emissions for this project. To relax any of these conditions will require a permit modification.
- Each combustion turbine shall operate below 50% base load for no more than two hours per day.

This BACT determination is much more stringent than the standards of NSPS, Subpart GG. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. In addition, the permittee shall install, calibrate, operate, and maintain a certified NOx continuous emissions monitor (CEMS) to demonstrate continuous compliance with the BACT limits.

5.2 CARBON MONOXIDE (CO)

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion while operating the combustion turbine. In general, CO emissions are inversely proportional to NOx emissions for gas turbines. However, new advanced combustor designs have also been able to lower CO emissions concurrently with NOx emissions. It is noted that General Electric has guaranteed CO emissions performance for the Model PG7241(FA) at 9.0 ppmvd @ 15% O_2 for several projects.

Applicant's Proposed CO BACT

The applicant identified two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and efficient combustor design. An oxidation catalyst consists of a noble metal catalyst section incorporated into the combustion turbine exhaust. The catalyst promotes oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than under normal conditions. The control efficiency is primarily a function of gas residence time and can exceed 90%. For this project, the exhaust gas temperature of 1100°F is in the proper design range. The applicant recognized an oxidation catalyst as the top control. However, the applicant asserts that an oxidation catalyst would result in the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of approximately 2 inches of water column. The lost energy is equivalent to approximately 11,000 mmBTU per year.

Environmental Impacts: The air quality impacts of a DLN system are well below the significant impact levels for CO. There is no additional environmental benefit gained by installing an oxidation catalyst. The air quality impacts of a DLN system alone are well below the PSD significant levels and less than 0.1% of the AAQS.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of an oxidation catalyst would result in capital cost of $1,673,295 per unit. The annualized cost was estimated to be $561,759 per year. It was assumed that the catalytic system could remove an additional 74 tons of CO per year (90% control efficiency) over a DLN only system at 12 ppmvd @ 15% O_2. This results in a cost effectiveness for the oxidation catalyst of $7595 per ton of CO removed. No such costs would be associated with the efficient combustion of the Model PG7241(FA) gas turbine.

The applicant rejected the oxidation catalyst as not being cost effective and not producing any measurable reductions in air quality impacts. The applicant proposed the following as the best available controls:

Applicant's Proposed CO BACT

Normal Gas Firing Mode: 12.0 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 20.0 ppmvd @ 15% O_2 achieved by water injection

Department's CO BACT Determination

The Department also recognizes an oxidation catalyst as the top control for CO emissions. However, the Department disagrees with many of the applicant's assumptions as summarized below.

Energy Impacts: The Department agrees that installation of an oxidation catalyst *would* result in an energy penalty due to the pressure drop across the catalyst.

Environmental Impacts: The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination.

Economic Impacts: In general, the Department agrees that the addition of an oxidation catalyst would result in a cost effectiveness in the range of $6000 to $8000. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, and energy consumption. Similar to the discussion for NOx controls, the Department recognizes that the cost analysis has been significantly constrained for this project by the applicant's requested operation.

The Department also rejects the addition of an oxidation catalyst as not being cost effective for the project as limited by the applicant's requests. Therefore, the Department establishes the following CO standards as BACT for this project:

CO BACT Determination

Gas Firing, Normal and Peaking: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Gas Firing With Power Augmentation: 15.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Distillate Oil Firing: 20.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by water injection.

Corresponding mass emission limits will also be established for each mode of operation. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. The Department will include the specific conditions identified under NOx controls to ensure that a switch to based loaded units, conversion to combined cycle operation, or substitution with a different make or model of gas turbine will trigger the appropriate permitting actions.

5.3 PARTICULATE MATTER (PM/PM_{10}) AND SULFUR DIOXIDE (SO_2)

Discussion of PM, PM_{10} and SO_2 Emissions

Emissions of particulate matter and sulfur dioxide will result from the combustion of the natural gas and low sulfur distillate fuel. Limited testing indicates that most of the particulate matter emitted from the combustion turbine will be less than 10 microns in diameter (PM_{10}). Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants.

Applicant's Proposed PM, PM_{10}, and SO_2 BACT

The applicant indicated that a review of the EPA RACT/BACT/LAER Clearinghouse did not reveal any post-combustion controls were required for any gas/oil fired combustion turbine projects. Uncontrolled particulate matter emissions are estimated to be less than 0.01 grain per dscf of exhaust gas, which is typically specified as controlled emissions from a baghouse. The use of natural gas as the primary fuel and the restricted use (500 hours per year or less) of very low sulfur (0.05% sulfur by weight or less) distillate oil will result in very low emissions of SO_2.

Applicant's Proposal for PM, PM_{10}, and SO_2 BACT

Each combustion turbine shall be fired primarily with pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF. Low sulfur distillate oil containing no more than 0.05% sulfur by weight shall be fired only as a backup fuel for no more than 500 hours per year.

The applicant indicated that recent BACT determinations for large combustion turbine projects specified such clean fuels as BACT.

Department's PM, PM_{10}, and SO_2 BACT Determination (Revised 06/06/00)

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. Similarly, there are scrubbers available to further reduce SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas as the primary fuel and to fire a restricted amount of very low sulfur distillate oil as the backup fuel. The Department agrees that further control of particulate matter and sulfur dioxide emissions with one of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case. In addition, a fuel specification for sulfur limits the maximum potential emissions that the gas turbine could emit. The Department establishes the following work practice standards as BACT for PM, PM_{10}, and SO_2.

PM, PM_{10}, and SO_2 BACT

EPA Region 4 commented that the BACT standard for particulate matter should include a mass emissions limit and at least an initial test. The applicant requested that the visible emissions rate for gas firing with the dual fueled combustion be raised to 10%. At this time, the Department is unable to adequately document that the measurement of particulate matter emissions from large gas turbines is technically infeasible. Therefore, the Department revised the initial Draft Permit to include the following standards.

Particulate Matter. When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load. The permittee shall demonstrate compliance by conducting tests in accordance with EPA Method 5 (or 17, if applicable).

Fuel Specifications. Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. Because the maximum potential SO_2 emissions are limited by the fuel sulfur specification, no emissions performance testing will be required. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit.

VE Standard. When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit.

5.4 PSD SYNTHETIC MINOR LIMITS

Volatile Organic Compounds: VOC emissions result from incomplete combustion when firing natural gas and low sulfur distillate fuel oil. Large combustion turbines such as the Model PG7241(PA) offer high temperatures with very efficient combustion resulting in low levels of volatile organic compounds. Therefore, the Department establishes the following standards as PSD synthetic minor limits for VOC:

Gas Firing, All Modes: 1.5 ppmvw
Oil Firing, Backup Fuel: 3.0 ppmvw

Corresponding mass emission limits will also be established for each mode of operation. These standards limit the potential annual emissions of VOC to less than the Significant Emission Rate of 40 tons per year. Initial compliance with the VOC emissions standard shall be demonstrated by conducting performance tests in accordance with EPA Methods 25 or 25A. EPA Method 18 may be used as an optional method to account for the non-regulated methane fraction of the measured VOC emissions. Compliance shall also be demonstrated during the fiscal year prior to renewing each operation permit.

6.0 OTHER EMISSIONS UNITS

6.1 TWO NATURAL GAS FUEL HEATERS

Each fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas. For continuous operation, total emissions of PM/PM_{10}, SO_2 and VOC are each less than 1 ton per year and emissions of CO and NOx are each less than 10 tons per year. These emissions represent much less than 3% of the total controlled emissions for this project. For these small emissions units, the Department determines that efficient combustion and the firing of natural gas to be BACT.

6.2 OIL STORAGE TANK

A common storage tank (2.1 million gallon) supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbines Nos. 8A and 8B. Because VOC emissions are estimated to be less than 1 ton per year, the Department determines BACT to be the storage of only distillate fuel oil in this tank and compliance with NSPS Subpart Kb which requires the permittee to keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. These records shall be retained for the life of the facility.

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

The following table summarizes the BACT standards determined by the Department for this project. Similar limits will be specified as conditions of the permit.

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal And Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Peak load; initial and annual tests All loads, certified CEM data

NOx (Cont'd)	Gas W/Peaking	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg. 15.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Peak load; initial/renewal tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr CEMS avg.	Base load; initial and annual tests All loads, certified CEM data
SO_2, PM/PM_{10}	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
Synthetic Minor Emission Standard			
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits

Note: PA means "power augmentation". The mass emission limits were based on 100% base load, maximum heat input, the fuel higher heating values, compressor inlet conditions of 35° F and 20% RH for normal gas and oil firing, and compressor inlet conditions of 80-95° F and 60% RH for gas firing with power augmentation.

According to the applicant, emissions data from General Electric was, *"... adjusted to reflect degradation when the units operate over time and performance improvements beyond that provided for by the manufacturer's guarantee."* To account for this overall "degradation", the applicant increased the mass flow rate through the turbine by approximately 11%. This resulted in higher fuel consumption and predicted mass emission rates. However, the Department has reviewed many projects for peaking units as well as projects with power augmentation. The Department believes it is inappropriate to permit emissions increases that result from an applicant's choice to operate under conditions that will significantly degrade the unit such that the manufacturer will no longer guarantee emissions or performance. Therefore, the Department developed mass emission limits based on General Electric's maximum emissions performance estimates, similar limits in recent Department permits for the Model PG7241(FA) gas turbine, and the following conditions:

- For normal gas firing and backup oil firing, mass emission limits were based on operation at base load with a compressor inlet air temperature of 35° F.
- For gas firing with power augmentation, mass emissions limits were based on operation at base load with a compressor inlet air temperature of 95° F for NOx, and a compressor inlet temperature of 80° F for CO (worst-case scenarios).
- Information provided by the applicant did not suggest that the gas turbine would have problems complying with GE's guaranteed CO emissions level of 9 ppmvd @ 15% O_2 for normal gas firing.
- For normal gas firing, General Electric data indicates NOx emissions of 61 lb/hour (9 ppmvd @ 15% O_2) at 35° F. The Department allowed 10 ppmvd @ 15% O_2 with compliance demonstrated by CEMS data on a 3-hour block average as opposed to other Department permits containing long-term 24-hour block averages. The Department believes the slightly higher limit combined with the shorter averaging period better defines peaking operation. To account for the increase, the Department considered the following items in establishing the NOx mass emissions limit: the GE mass emission rate at 59° F is 59 lb/hour; the GE mass emission rate at 35° F is 61 lb/hour; and the mass emission limit for the recent Desoto Power project was 64 lb/hour.

The application indicates that recently issued PSD permits specify emissions limits similar to those requested by the applicant. In support of the Department's BACT determination, the following tables offer a comparison of the Department's emissions limits, the applicant's proposed emission limits, and the emission limits specified for a recent similar project (Desoto Power) consisting of General Electric Model PG7241(FA) gas turbines.

Comparison of FPL Martin With Desoto Power

Emissions Per Unit - Gas/Oil Firing

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	67	82	86
NOx	183	208	252
PM/PM_{10}	17	19	20
SAM	< 3	< 3	4
SO_2	33	32	55
VOC	6	6	11

Emissions Per Unit - Gas Only (Including High Power Modes)

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	56	79	72
NOx	113	144	109
PM/PM_{10}	15	17	17
SAM	< 1	< 1	< 1
SO_2	9	9	8
VOC	5	5	5

Comments:

It should be noted that the Desoto Power project allows up to 3390 hours per year of operation with no more than 1000 hours per year of oil firing. The higher emissions are the result of the increased oil firing. In addition, the Desoto Power project also allows up to 12 ppmvd of CO emissions, but did not permit power augmentation.

The gas only case is presented as more typical of actual operations. The Department's draft permit for the proposed FPL Martin project results in approximately 7 tons of NOx per year more than the Desoto Power project. About half of this is the result of limited power augmentation and about half from the slightly higher hourly emission limit. Lower CO emissions are the result of the 9 ppmvd limit established for the FPL Martin project compared to the 12 ppmvd limit specified for the Desoto Power project.

7.2 BACT EXCESS EMISSIONS ALLOWED

1. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

2. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

   (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

   (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

   (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

   (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

[Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

8.0 RECOMMENDATION AND APPROVAL

The permit project engineer is Jeff Koerner. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer at 850/414-7268 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Determination By:

Jeffery J. Koerner 7-18-00

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

C. H. Fancy 7/21/00

C. H. Fancy, P.E., Chief (Date)
Bureau of Air Regulation

Approved By:

C. H. Fancy 7/21/00

Howard L. Rhodes, Director (Date)
for Division of Air Resources Management

APPENDIX E - EMISSIONS STANDARDS SUMMARY

For informational purposes only, the following table summarizes the emissions standards specified in this permit. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines (8A and 8B)

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal and Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O_2, 3-hr avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O_2, 3-hr avg.	Peak load; initial and annual tests All loads, certified CEM data
	Gas, Peaking	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg. 15.0 ppmvd @ 15% O_2, 3-hr avg.	Peak load; initial/renewal tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr avg.	Base load; initial and annual tests All loads, certified CEM data
PM/PM_{10}, SO_2	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests

<u>Note</u>: The mass emission limits for were based on the following:

- Gas Firing, Normal: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW.
- Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW.
- Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW.
- *Distillate Oil*: At a compressor inlet air temperature of 35° F and firing 2000 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW.

Note: All heat input values are based on the higher heating values (HHV) of the fuels.

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

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

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

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

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

(b) Determination of Prevention of Significant Deterioration (X); and

(c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

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

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

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

APPENDIX GG - NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, Subpart A, General Provisions, including:

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Máintenance Requirements
- 40 CFR '60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

This emissions unit is subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. The following conditions follow the original NSPS rule language and numbering scheme. Regulations that are not applicable were omitted for clarity. Because this emissions units is subject to an NSPS, it is also subject to the following federal provisions: 40 CFR 60, Subpart A, General Provisions for sources subject to an NSPS, adopted by reference in Rule 62-204.800(7)(d), F.A.C.; 40 CFR 60, Appendix A - Test Methods, Appendix B - Performance Specifications, Appendix C - Determination of Emission Rate Change, Appendix D - Required Emissions Inventory Information, Appendix F - Quality Assurance Procedures, adopted by reference in Rule 62-204.800(7)(e).

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10 million BTU per hour, based on the lower heating value of the fuel fired.

40 CFR 60.331 DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

60.332 STANDARD FOR NITROGEN OXIDES.

(a) On and after the date of the performance test required by Sec. 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b) of this section shall comply with one of the following, except as provided in paragraphs (e) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

Where:

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

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

F = NO emission allowance for fuel-bound nitrogen as defined in the following table:

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (Percent By Weight)	"F" (NOx Percent By Volume)
$N < 0.015$	0
$0.015 < N < 0.1$	0.04(N)
$0.1 < N < 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

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

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 100 million Btu per hour based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(f) Stationary gas turbines using water or steam injection for control of NOx emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

On and after the date on which the performance test required to be conducted by Sec. 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

40 CFR 60.334 MONITORING OF OPERATIONS.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within +/- 5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under Sec. 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with Sec. 60.332 by the performance test required in Sec. 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in Sec. 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under Sec. 60.335(a).

(2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) Ice fog. Each period during which an exemption provided in Sec. 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be

reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR 60.335 TEST METHODS AND PROCEDURES.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in Sec. 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Secs. 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(P_r/P_o)^{0.5}\,(e^{19\,(H_o - 0.00633)})\,(288°K/T_a)^{1.53}$$

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

(2) The monitoring device of Sec. 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Sec. 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference--see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some

fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

(e) To meet the requirements of Sec. 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT

FIGURE 1 – QUARTERLY PERFORMANCE SUMMARY REPORT
GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEMS

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NOx TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ________________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ____________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [a]: ________________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Title

____ ____________________
Signature *Date*

FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

RECEIVED

JUN 19 2000

BUREAU OF AIR REGULATION

June 15, 2000

Mr. Jeff Koerner, P.E.
State of Florida
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: FPL Martin Peaking Project
Proof of Publication – Permit #0850001-008-AC (PSD-FL-286)

Dear Jeff:

Enclosed for your use please find the subject Proof of Publication for the PSD permit for the Martin Peaking Units. The notice appeared in the Stuart News on June 13th.

I would be pleased to answer any questions you may have regarding this project. At your convenience, please feel free to contact me at (561) 691-7058 or via email at rich_piper@fpl.com.

Very truly yours,

Richard Piper
Licensing Manager
Florida Power & Light Company

cc:
FDEP Southeast District Office
Hamilton S. Oven, P.E.
EPA
NPS

SCRIPPS HOWARD

STUART NEWS
PORT ST. LUCIE NEWS

(an edition of the Stuart News)

Martin County and St. Lucie County, Florida

1939 S. Federal Highway, Stuart, FL 34994

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF MARTIN; COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, Mary T. Byrne, who on oath says that she is Classified Legal Advertising Representative of the Stuart News and the Port St. Lucie News, a daily newspaper published at Stuart in Martin County, Florida: that the attached copy of advertisement was published in the Stuart/Port St. Lucie News in the following issues below. Affiant further says that the said Stuart/Port St. Lucie News is a newspaper published in Stuart in said Martin County, Florida, with offices and paid circulation in Martin County and St. Lucie County, Florida, and that said newspapers have heretofore been continuously published in said Martin County, Florida, daily and distributed in Martin and St. Lucie County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the securing this advertisement for publication in the said newspaper. The Stuart News has been entered as second class matter at the Post Offices in Stuart, Martin County, Florida and Ft. Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Date	Copyline	PO #
1917205	06/13/2000	DEP PERMIT	

Subscribed and sworn to me before this date:

06/13/2000

Mary T. Byrne

Catherine Hudson

Notary Public

CATHERINE HUDSON
Notary Public, State of Florida
My comm. exp. Apr. 19, 2004
Comm. No. CC927458

BEST AVAILABLE COPY

NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
FPL Martin Power Plant - Martin County
Draft Permit No. 0850001-008-AC (PSD-FL-286)
Two New Simple Cycle Combustion Turbines
New Emissions Units 011-014

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power and Light (FPL) Company to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County, approximately seven miles north of Indiantown on State Road 710. The applicant proposes to install of two simple cycle gas turbines, two natural gas fired fuel heaters, and a distillate oil storage tank. Each gas turbine is a General Electric Model PG7241(FA) combustion turbine-electrical generator set with a nominal generating capacity of 170 MW. A determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), and sulfur dioxide (SO2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. Although this property is located at a plant subject to the Power Plant Siting Act, it provides for no expansion in steam generating capacity. The applicant's authorized representative is John M. Lindsay, Plant General Manager, for the FPL Martin Power Plant. The applicant's mailing address is P.O. Box 176, Indiantown, FL 34956.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry-low NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to an equivalent fuel consumption limit of 3390 hours of maximum natural gas firing during any consecutive 12 months, of which no more than an equivalent 500 hours may be distillate oil firing. The draft permit authorizes steam injection for power augmentation (400 hours per year) and high temperature peaking (60 hours per year) when firing natural gas during periods of peak electrical power demand, typically summer. During power augmentation, the draft permit limits CO and NOx emissions to 15 and 12 ppmvd corrected to 15% oxygen, respectively. During high temperature peaking, the draft permit limits CO and NOx emissions to 9 and 15 ppmvd corrected to 15% oxygen, respectively.

e following table summarizes the final project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

ollutant	Project Potential Annual Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
O	138.5	100	Yes	Yes
Ox	374.5	40	Yes	Yes
M/PM10	35.0	15	Yes	Yes
AM	5.1	7	No	No
O2	66.5	40	Yes	Yes
OC	13.7	40	No	No

An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue (P.O. Box 15425)
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6755

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Pub.: June 13, 2000

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

June 9, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

John M. Lindsay, Plant General Manager
Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: DEP File No. 0850001-008-AC (PSD-FL-286)
FPL Martin Plant – Revised Draft Permit
Addition of Two 170 MW Simple Cycle Peaking Combustion Turbines

Dear Mr. Lindsay:

Enclosed is one copy of the Revised Draft Permit to install two new simple cycle combustion turbines at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Department's Technical Evaluation and Preliminary Determination, Intent to Issue Air Construction Permit, and the Public Notice of Intent to Issue Air Construction Permit are also included. This is a revision of the Draft Permit previously issued on May 5, 2000. Changes were made to accommodate several requests made by FPL.

The Public Notice of Intent to Issue Air Construction Permit must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

CH Fancy

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/jfk

Enclosures

In the Matter of an
Application for Permit by:

John M. Lindsay, Plant General Manager
Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

ARMS Project No. 0850001-008-AC
PSD Permit No. PSD-FL-286
FPL Martin Power Plant - Martin County
Emission Units 011 – 014
Revised Draft Permit

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of draft permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. This is a revision of the Draft Permit previously issued on May 5, 2000. Changes were made to accommodate several requests made by FPL. The Department withdraws the initial Draft Permit and issues this Revised Draft Permit in its place.

The applicant, Florida Power and Light, applied on February 19, 2000 to the Department for an air construction permit to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Draft Permit authorizes the installation of two simple cycle, dual-fuel, General Electric Model PG7241(FA) combustion turbines-electrical generator sets, each having a generating capacity of 170 MW.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's

Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6-9-00 to the person(s) listed:

Mr. John M. Lindsay, FPL*
Mr. Richard G. Piper, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 6-9-00
(Date)

BEST AVAILABLE COPY

Z 341 355 309

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to John Lindsay	
Street & Number FPL - Martin	
Post Office, State, & ZIP Code Indiantown Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 6-9-00 0850001-008-AC PSD-FI-086	

PS Form **3800**, April 1995

SENDE[R] ... [COMPLETE THIS SECTIO]**N ON DELIVERY**

- Complete items 1, ... item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

John Lindsay
FPL - Martin Plant
PO Box 176
Indiantown, Fl
34956

A. Received by ... Clearly)
B. Date of Delivery 6-12-00

C. Signature
X [signature]
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* Z 341 355 309

PS Form **3811**, July 1999 Domestic Return Receipt 102595-99-M-1789

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

FPL Martin Power Plant - Martin County

Draft Permit No. 0850001-008-AC (PSD-FL-286)
Two New Simple Cycle Combustion Turbines
New Emissions Units 011 - 014

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power and Light (FPL) Company to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The applicant proposes to install of two simple cycle gas turbines, two natural gas fired fuel heaters, and a distillate oil storage tank. Each gas turbine is a General Electric Model PG7241(FA) combustion turbine-electrical generator set with a nominal generating capacity of 170 MW. A determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. Although this project is located at a plant subject to the Power Plant Siting Act, it provides for no expansion in steam generating capacity. The applicant's authorized representative is John M. Lindsay, Plant General Manager, for the FPL Martin Power Plant. The applicant's mailing address is P.O. Box 176, Indiantown, FL 34956.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry low-NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to an equivalent fuel consumption limit of 3390 hours of maximum natural gas firing during any consecutive 12 months, of which no more than an equivalent 500 hours may be distillate oil firing. The draft permit authorizes steam injection for power augmentation (400 hours per year) and high temperature peaking (60 hours per year) when firing natural gas during periods of peak electrical power demand, typically summer. During power augmentation, the draft permit limits CO and NOx emissions to 15 and 12 ppmvd corrected to 15% oxygen, respectively. During high temperature peaking, the draft permit limits CO and NOx emissions to 9 and 15 ppmvd corrected to 15% oxygen, respectively

The following table summarizes the final project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	Project Potential Annual Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	138.5	100	Yes	Yes
NOx	374.5	40	Yes	Yes
PM/PM_{10}	35.0	15	Yes	Yes
SAM	5.1	7	No	No
SO_2	66.5	40	Yes	Yes
VOC	13.7	40	No	No

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An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road. Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue (P.O. Box 15425)
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6755

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

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TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Florida Power and Light Company – Martin Plant

Addition of Two Simple Cycle Combustion Turbines
Emissions Units 011 - 014

Martin County

ARMS Facility ID No. 0850001

Project No. 0850001-008-AC

Permit No. PSD-FL-286

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

June 9, 2000
(Revised)

This document describes the overall project, discusses rule applicability, summarizes the determination of Best Available Control Technology, reports the air quality impacts, and makes a preliminary determination on the requested permitting action. It is organized in the following sections:

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

1.2 Reviewing and Processing Schedule

02/19/00 Department received the PSD air pollution construction permit application.

02/23/00 Department mailed copies to EPA Region 4 and the National Park Service

03/10/00 Department requested additional information (No. 1).

03/24/00 Department received additional information (No. 1).

04/06/00 Department requested additional information (No. 2).

04/10/00 Department received additional information (partial No. 2).

04/14/00 Department received additional information (remaining No. 2) from the applicant making application complete.

05/05/00 Department issued initial Draft Permit package.

05/16/00 Department received several requests for substantial changes to the initial Draft permit including revised stack dimensions, an alternate method of operation, revised heat input, and equivalent fuel consumption limits to replace hours of operation restrictions. The Department considered additional supporting information, including modeling, in this Revised Draft Permit.

2.0 FACILITY INFORMATION

2.1 Facility Description

The existing FPL Martin Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the requested project will add two 170 MW simple cycle combustion turbines increasing the total nominal generating capacity to 2940 MW.

2.2 Facility Location

The existing facility is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46". This site is approximately 144 kilometers north of the Everglades National Park, a PSD Class I Area.

2.3 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.4 Regulatory Categories

Power Plant Siting: The existing facility is regulated pursuant to the Electric Power Plant and Transmission Line Siting Act. However, because no steam will be generated by this project, it is not subject to requirements of Chapter 403, Part II, F.S. or Chapter 62-17, F.A.C.

Title III – HAP: The existing facility is a major source of hazardous air pollutants. Emissions solely from the project do not exceed the major source thresholds for hazardous air pollutants. Therefore, a Section 112(g) case-by-case determination of Maximum Available Control Technology does not apply.

Title IV - Acid Rain: The existing facility is subject to Title IV, the federal Acid Rain program. The gas turbines will also be subject to the acid rain provisions.

Title V – Major Source: The existing facility is classified as a Title V major source of air pollution because emissions of at least one regulated air pollutant, such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, new projects must be reviewed for PSD applicability. Each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. requires a determination of Best Available Control Technology (BACT). For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: This project includes emissions units that are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

3.0 PROPOSED PROJECT

3.1 Project Description

The applicant, Florida Power and Light Company, proposes to install two new simple cycle combustion turbines, two gas-fired natural gas fuel heaters, a common distillate oil storage tank, and associated equipment at the existing FPL Martin Power Plant. Each combustion turbine consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 80 feet tall and 20.5 feet in diameter. Each unit is designed to produce a nominal 170 MW of electrical power fired with natural gas as the primary fuel and low sulfur distillate oil as a backup fuel. The applicant proposes to limit use of the gas turbines as "peaking units" by restricting the fuel consumption to an equivalent of 3390 hours per year per unit. Of this total, no more than an equivalent 500 hours per year would occur when firing low sulfur distillate oil as a backup fuel. In addition, the applicant requests approval for "power augmentation" and "high temperature peaking" as authorized methods of operation when firing natural gas. The high power modes result in higher CO and NOx emissions than those for normal gas firing and are discussed in more detail under the NOx BACT Determination. Of the allowable 3390 hours per year, power augmentation would be limited to no more than 400 hours per year and peaking to no more than 60 hours per year. To control nitrogen oxide emissions, the applicant proposes dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. Combustion design with clean fuels will minimize emissions of other pollutants.

As a result of fuel combustion, this project will emit emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of CO, NOx, PM/PM_{10}, and SO_2 exceed the Significant Emissions Rates established in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, the Department must establish emissions standards that represent a determination of Best

Available Control Technology (BACT) for these pollutants. The permit will also include emissions standards for VOC as a PSD-synthetic minor pollutant. This document presents a detailed description of the PSD applicability analysis and BACT determination. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanying the Department's Intent to Issue Permit package.

3.2 Project Emissions

Table 3.2 This table summarizes potential emissions increases and the resulting PSD applicability.

Pollutant	Proposed[a,c] PTE (Tons Per Year)	Draft Permit[b,c] PTE (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	170	139	100	Yes	Yes
NOx	423	375	40	Yes	Yes
PM	38	35	25	Yes	Yes
PM_{10}	38	35	15	Yes	Yes
SAM	5	5	7	No	No
SO_2	64	67	40	Yes	Yes
VOC	13	14	40	No	No

a - For each gas turbine, the potential emissions were based on: 2390 hours per year of normal gas firing, 500 hours per year of gas firing in the "high power modes", 500 hours per year of distillate oil firing as a backup fuel, and the "annual" hourly emission rates (applicant's initial request).

b - For each gas turbine, the potential emissions were based on: 2390 hours per year of normal gas firing, 400 hours per year of gas firing in the power augmentation mode, 60 hours per year of high temperature peaking, 500 hours per year of distillate oil firing as a backup fuel, and the maximum mass emission rates specified in the draft permit.

c - Potential emissions also include minor emissions from two gas fuel heaters and a distillate oil tank.

As shown, the proposed combustion turbine project is subject to PSD review and determinations of Best Available Control Technology (BACT) for CO, NOx, PM/PM_{10} and SO_2.

4.0 RULE APPLICABILITY

4.1 PSD Review

As previously discussed, the existing facility is considered a PSD major source and is located in Martin County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). Therefore, the project is subject to a review for the Prevention of Significant Deterioration of Air Quality accordance with Rule 62-212.400, F.A.C. The PSD review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each significant pollutant exceeding the Significant Emission Rates defined in Table 212.400-2, F.A.C. For this project, a BACT determination is required for CO, NOx, PM/PM_{10} and SO_2. The second part requires an Air Quality Analysis consisting of: air dispersion modeling to estimate the resulting ambient pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4.2 State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following state rules and regulations of the Florida Administrative Code.

Citation	Description
Chapter 62-4	Permitting Requirements
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution
Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

4.3 Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Citation	Description
40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 52.166	Prevention of Significant Deterioration
40 CFR 60	NSPS Subpart Kb - Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984
40 CFR 60	NSPS Subpart GG – Stationary Gas Turbines
40 CFR 60	Subpart A, General Provisions for NSPS Sources
40 CFR 60	Applicable Appendices
40 CFR 72	Acid Rain Permits
40 CFR 73	Allowances
40 CFR 75	Monitoring
40 CFR 77	Acid Rain Program - Excess Emissions

5.0 SUMMARY OF BACT DETERMINATION

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry low-NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to an equivalent fuel consumption limit of 3390 hours of maximum natural gas firing during any consecutive 12 months, of which no more than an equivalent 500 hours may be distillate oil firing. The draft permit authorizes steam injection for power augmentation (400 hours per year) and high temperature peaking (60 hours per year) when firing natural gas during periods of peak electrical power demand, typically summer. During power augmentation, the draft permit limits CO and NOx emissions to 15 and 12 ppmvd corrected to 15% oxygen, respectively. During high temperature peaking, the draft permit limits CO and NOx emissions to 9 and 15 ppmvd corrected to 15% oxygen, respectively. A detailed analysis of the BACT Determination is presented in Appendix BD of the draft permit included with the Department's Intent to Issue Permit. The following table summarizes the resulting emissions standards.

Table 5-A. Summary of Emissions Standards

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines (8A and 8B)

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal and Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O_2, 3-hr avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O_2, 3-hr avg.	Peak load; initial and annual tests All loads, certified CEM data
	Gas, Peaking	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg. 15.0 ppmvd @ 15% O_2, 3-hr avg.	Peak load; initial/renewal tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr avg.	Base load; initial and annual tests All loads, certified CEM data
PM/PM_{10}, SO_2	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests

6.0 AIR QUALITY ANALYSIS

6.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: CO, NOx, PM_{10} and SO_2. NOx, PM_{10} and SO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

The applicant's initial CO, NOx, PM_{10} and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for CO, NOx, PM_{10} and SO_2; and
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model 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 West Palm Beach, Florida (surface and upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

6.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst load conditions the ISCST3 model was used to evaluate dispersion of emissions from the simple cycle facility for three loads (50, 75% and 100%) and three seasonal operating conditions (summer, winter, and average) for each fuel type. Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If modeling at worst load conditions shows significant impacts, additional multi-facility modeling is required to determine the project's impacts on existing air quality and any applicable AAQS or PSD increments.

Receptors were placed around the facility, which is located in a PSD Class II area. The receptor grid for predicting maximum concentrations in the vicinity of the project was a polar receptor grid that contained 24 rings with each ring containing 36 radial receptors spaced 10° apart. The dimensions of the grid were centered upon the proposed combustion turbines. Along each radial, receptors were located at distances ranging from 200 m out to 30 km. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility. For the Class I analysis, the maximum concentrations were predicted at 53 receptors surrounding the PSD Class I area of the Everglades National Park (ENP). These receptors have been provided by the FDEP for use in previous applications. The table below shows the results of the significant impact modeling.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.04	1	NO
	24-hour	0.5	5	NO
	3-hour	4.0	25	NO
PM_{10}	Annual	0.009	1	NO
	24-hour	0.12	5	NO
CO	8-hour	2	500	NO
	1-hour	13	2000	NO
NO_2	Annual	0.14	1	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (ENP)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.004	0.1	NO
	24-hour	0.13	0.2	NO
	3-hour	0.64	1.0	NO
PM_{10}	Annual	0.001	0.2	NO
	24-hour	0.02	0.3	NO
NO_2	Annual	0.012	0.1	NO

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project.

6.4 Impacts Analysis

Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with a conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for SO_2, PM_{10}, CO and NOx, as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels, which are in turn less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NOx and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species.

A regional haze analysis that used the CALPUFF modeling system in a screening mode otherwise known as CALPUFF Lite was performed. CALPUFF is a long-range transport model recommended by the National Park Service (NPS) for use in regional haze analyses because of its ability to handle atmospheric chemical transformations as well as wet and dry deposition. The results of the CALPUFF Lite modeling analysis indicated a predicted change in visibility of 4.83%, which is less than the NPS threshold of 5%. Therefore, the proposed project is not predicted to have an adverse impact on visibility and regional haze in the ENP.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require few new permanent employees, which will cause no significant impact on the local area.

6.5 Revised Analysis

The applicant requested revised stack dimensions of 20.5 feet in diameter and 80 feet tall. This would usually result in better dispersion and lower ambient impacts. However, the Department requested additional modeling to support this supposition. As expected, the additional modeling indicates that the requested stack dimensions would result in little, if any, changes to the previous Air Quality Analysis.

7.0 CONCLUSION

The Public Service Commission has determined that a number of power projects will be needed over the next few years to meet the rising electrical power needs throughout the State of Florida. This project is a response to predicted statewide growth and an effort to meet the required reserve capacity. The proposed project has a small overall physical "footprint," low water requirements, and low air emissions per unit of electric power generated compared to similar projects with intermittent operation.

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. This determination is based on the technical review of the complete PSD application, reasonable assurances provided by the applicant, the preliminary determination of Best Available Control Technology (BACT), and the conditions specified in the Draft Permit. Jeff Koerner is the permitting engineer responsible for reviewing the application, recommending the BACT determination, and drafting the permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for this project.

(REVISED DRAFT)

PERMITTEE:

Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911
Expires:	July 1, 2002

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality. The permit authorizes installation at the existing power plant of two simple cycle, 170 MW combustion turbines with electrical generator sets fired primarily with natural gas.

The project will be constructed at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46".

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A - Terminology
Appendix BD - Department's BACT Determinations
Appendix E - Emissions Standards Summary
Appendix GC - Construction Permit General Conditions
Appendix GG - NSPS Subpart GG Requirements for Gas Turbines
Appendix XS - CEMS Excess Emissions Report

(DRAFT)

____
Howard L. Rhodes, Director
Division of Air Resources Management

Date: __________________

FACILITY DESCRIPTION

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's and are fired with low sulfur residual oil and natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	Emission Unit Description
011	Simple Cycle Unit No. 8A: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
012	Simple Cycle Unit No. 8B: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 8A and 8B.

REGULATORY CLASSIFICATION

HAPs: Based on the Title V permit, the existing facility is a major source of hazardous air pollutants (Title III). This project is not, in and of itself, major for HAPs.

Acid Rain: The existing facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: The existing facility is a Title V major source of air pollution because potential emissions of at least one pollutant such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceed 100 tons per year.

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, each new project requires a PSD applicability review. For each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C., a determination of Best Available Control Technology (BACT) is required. For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: Emissions units are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 02/19/00 and all related correspondence.
- Initial Draft Permit issued on May 5, 2000 and subsequent correspondence on revisions

The following conditions apply to all emissions units and activities defined for this project.

GENERAL REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.
2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, 400 North Congress Avenue, P.O. Box 15425, West Palm Beach, Florida 33416-5425. The phone number is 561/681-6600 and the fax number is 561/681-6755.
3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.
4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
5. Applicable Regulations. Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]
8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]
9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for routine operation of the permitted emissions units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Applicable Test Procedures

    (a) *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)1. and 2., F.A.C.]

(b) *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

(c) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

20. Determination of Process Variables

(a) *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

21. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS

22. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

REPORTS

23. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

24. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

This section of the permit addresses the following new emissions units.

EU ID No.	Common Emission Unit Description
011 012	<u>Simple Cycle Units Nos. 8A and 8B</u>: Each unit consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 80 feet tall and 20.5 feet in diameter, and associated support equipment. Natural gas is the primary fuel with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10}, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. The capacities by fuel and method of operation are: *Natural Gas* • Normal Firing: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,461,000 acfm at 1095° F. • Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,380,000 acfm at 1115° F. • Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,488,000 acfm at 1110° F. *Distillate Oil*: At a compressor inlet air temperature of 35° F and firing 2000 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW. The water injection rate for NOx control will be approximately 131,000 pounds per hour. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,539,000 acfm at 1075° F. Note: All heat input values are based on the higher heating values (HHV) of the fuels.

APPLICABLE STANDARDS AND REGULATIONS

1. <u>BACT Determinations</u>: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}) and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]
2. <u>NSPS Requirements</u>: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (a) *Subpart A, General Provisions*, incuding:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

(b) *Subpart GG, Standards of Performance for Stationary Gas Turbines* are identified in *Appendix GG* of this permit. These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

PERFORMANCE RESTRICTIONS

3. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines with electrical generator sets, each designed to produce a nominal 170 MW of electrical power. [Applicant Request; Design]

4. Permitted Capacity: The heat input rates (HHV) to each combustion turbine shall not exceed the following:

   (a) Normal Gas Firing: 1860 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 182 MW.

   (b) Gas Firing With Power Augmentation (Steam Injection): 1800 mmBTU per hour of natural gas with a compressor inlet air temperature of 59° F and producing a maximum 180 MW.

   (c) Gas Firing With Peaking: 1920 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 190 MW.

   (d) Distillate Oil Firing: 2008 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 191 MW.

   The heat input rates are based on the higher heating values (HHV) of 23,127 BTU/lbm for natural gas and 19,490 BTU/lbm for distillate oil. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

5. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

6. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by this permit. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in this permit. [Application; Rule 62-210.200(PTE), F.A.C.]

7. Alternate Gas Firing Methods of Operation

   (a) Power Augmentation Mode: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 400 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Power augmentation when firing distillate oil is prohibited.

   (b) High Temperature Peaking Mode: In accordance with the manufacturer's recommendations, each combustion turbine may be operated in a high temperature peaking mode when firing natural gas to provide additional power during periods of peak electrical power demands. Peaking is achieved through the automated gas turbine control system by allowing slightly higher exhaust temperatures, calculating a new combustion reference temperature for the peak load, and adjusting the fuel distribution between the fuel nozzles to maintain lean pre-mix firing. During the transfer from base load to peak load and during peak load operation, each unit will remain in the per-mix steady state mode. Each unit shall not exceed 60 hours of peaking during any consecutive 12 months. To qualify as "peaking mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the peaking mode, the operator shall log the date, time, and new mode of operation. Peaking when firing distillate oil is prohibited.

   [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

8. Restricted Operation

   (a) Gas Firing: Each combustion turbine shall fire no more than 5,902,588,000 standard cubic feet of natural gas during any consecutive 12 months (equivalent to 3390 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° F).

   (b) Oil Firing: Each combustion turbine shall fire no more than 7,358,350 gallons of distillate oil during any consecutive 12 months (equivalent to 500 hours per year at the maximum firing rate for a compressor inlet temperature of 59° F). If oil is fired, the natural gas consumption limit shall be reduced by 118 standard cubic feet of gas for every gallon of distillate oil fired.

   The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each method of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

9. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS CONTROLS

10. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion

process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, exhaust temperatures, heat input, and fully automated startup and shutdown. [Design; 62-212.400(BACT), F.A.C.]

11. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine . [Design; Rule 62-212.400(BACT), F.A.C.]

12. Tuning: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. The permittee shall provide at least 5 days advance notice prior to any tuning session. [Design; Rule 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix E of this permit.}

13. Carbon Monoxide (CO)

(a) *Gas Firing, Normal and Peaking*: When firing natural gas under normal operating conditions and in the high temperature peaking mode, CO emissions from each combustion turbine shall not exceed 32.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load.

(c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

14. Nitrogen Oxides (NOx)

(a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(c) *Gas Firing With Peaking*: When firing natural gas with high temperature peaking, NOx emissions from each combustion turbine shall not exceed 105.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(d) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332]

15. Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2)

(a) *Particulate Matter*: When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load.

(b) *Fuel Specifications*. Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

(c) *VE Standard*. When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

16. Volatile Organic Compounds (VOC)

(a) *Gas Firing*: When firing natural gas under any method of operation, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

(b) *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such

emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

18. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:
    (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.
    (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.
    (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.
    (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.
    (e) If the permittee provides at least 5 days advance notice prior to tuning in accordance with the manufacturer's recommendations, up to three 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each gas turbine due to excess NOx emissions resulting from tuning. Note: It is expected that no more than two tuning sessions would occur each year.

    [Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR 60.40a(b)]

20. Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C.
    (a) EPA Method 5 or 17 - Determination of Particulate Matter Emissions from Stationary Sources
    (b) EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources
    (c) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources
    (d) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources
    (e) EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
    (f) EPA Methods 25 or 25A - Determination of Volatile Organic Concentrations *{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.}*

    No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [40 CFR 60, Appendix A; Rule 62-204.800, F.A.C.]

21. Initial Tests Required: Initial performance tests to demonstrate compliance with each emission standard for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup distillate oil firing shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of each emissions unit. Initial performance tests shall be conducted for CO, NOx, PM, VOC and visible emissions. Tests for CO, NOx, and VOC shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. NOx performance tests shall be conducted in accordance with the requirements of 40 CFR 60, Subpart GG. For the initial performance tests, emissions data shall be presented in units of the BACT standards as well as the units specified in the Subpart GG emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

22. Annual Performance Tests: Annual performance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup distillate oil firing. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). CO and NOx performance tests shall be conducted concurrently. If conducted at permitted capacity, NOx emissions data collected during the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test.

    (a) For each combustion turbine that fires distillate oil for less than 200 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required.

    (b) For each combustion turbine that operates with power augmentation for less than 200 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.

    [Rule 62-297.310(7)(a)4., F.A.C.]

23. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for each combustion turbine to demonstrate compliance with the CO, NOx, PM, VOC and visible emissions standards for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup oil firing. Tests for CO, NOx, and VOC emissions shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. All tests shall be conducted within the 12 months prior to renewing the air operation permit. [Rule 62-297.310(7)(a)3., F.A.C.]

24. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment, including the replacement of dry low-NOx combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine. This does not apply to routine maintenance. [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

25. Combustion Turbine Testing Capacity

    (a) Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines.

    (b) Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity for each method of operation. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.

(c) For performance tests conducted when gas firing under the power augmentation mode and under the high temperature peaking mode, the permittee shall document that the combustion turbine was operating under "peak load" for the given ambient conditions. For power augmentation, the steam injection rate shall be no less than 100,000 pounds of steam per hour.

[Rule 62-297.310(2), F.A.C.; 40 CFR 60.335]

CONTINUOUS MONITORING REQUIREMENTS

26. NOx CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack to meet the requirements of the Acid Rain program and to demonstrate compliance with the NOx standards specified in this permit. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NOx monitoring devices shall comply with the certification requirements, quality assurance procedures, and all other provisions of the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of the following information: CEM equipment specifications, manufacturer, model, type, calibration and maintenance needs, and the proposed location.

(a) *Installation.* Each CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 75.62.

(b) *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Each valid 1-hour average shall be calculated using at least two valid data points at least 15 minutes apart.

(c) *Data Reporting.* Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 3-hour average. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of three valid 1-hour emission rates. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. Notification shall include either a written letter, a phone call, or a fax transmittal to the Compliance Authority. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required by this permit.

(d) *Data Exclusion for Compliance.* Unless prohibited by Rule 62-210.700(4), F.A.C., valid 1-hour monitoring averages shall not include periods of excess emissions due to startup, shutdown, documented malfunction, or the result of tuning as described and limited under Specific Condition 18 of this permit. Because such data may be excluded, the 3-hour average to determine compliance need not consist of *consecutive* 1-hour averages.

(e) *Alternate Methods of Operation.* Each 1-hour monitoring average consisting of any data collected during an alternate method of operation (oil firing, power augmentation, or peaking) shall be attributed entirely to the alternate method of operation. For each 3-hour average consisting of more than one method of operation, compliance shall be determined by prorating each emission standard based on the number of 1-hour averages represented. In event of a CEMS malfunction or occurrence of excess emissions while operating in the power augmentation or peaking modes, the permittee shall immediately cease power augmentation or peaking and revert to normal gas firing or shut down the combustion turbine.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-212.400(BACT), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

RECORDS

27. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

(a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan), natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance with the monitoring requirements of 40 CFR 60, Subpart GG.

(a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

(c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2), provided:

(1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

(2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

(3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d). [40 CFR 60, Subpart GG; Applicant Request]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of each mode of operation and the fuel consumption for each combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

30. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, periods of startup, shutdown and malfunction shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. Within 30 days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

This section of the permit addresses the following new emissions units.

EU ID No.	Emission Unit Description
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 8A and 8B.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb : Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE RESTRICTIONS

3. Equipment: The permittee is authorized to install, operate, and maintain the following emissions units and supporting equipment: two gas fuel heaters fired solely with natural gas (23.71 mmBTU per hour) designed to heat the natural gas supplied to simple cycle combustion turbines 8A and 8B; and one 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to simple cycle combustion turbines 8A and 8B. [Applicant Request]

4. Hours of Operation: The hours of operation for the gas fuel heaters and distillate oil storage tank are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Good Combustion: Visible emissions of 5% opacity or less from the gas fuel heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

RECORDS

6. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual amount of natural gas fired in the gas fuel heaters and the annual throughput of distillate oil for the storage tank . [Rule 62-210.370(3), F.A.C.]

7. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

°F	-	Degrees Fahrenheit
DEP	-	State of Florida, Department of Environmental Protection
DARM	-	Division of Air Resource Management
EPA	-	United States Environmental Protection Agency
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
SOA	-	Specific Operating Agreement
UTM	-	Universal Transverse Mercator
CT	-	Combustion Turbine
HRSG	-	Heat Recovery Steam Generator
DLN	-	Dry Low-NOx Combustion Technology
SCR	-	Selective Catalytic Reduction
OC	-	Oxidation Catalyst Technology for CO Control

RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example: [Rule 62-213.205, F.A.C.]
Where:
62 - identifies the specific Title of the F.A.C.
62-213 - identifies the specific Chapter of the F.A.C.
62-213.205 - identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001
Where:
099 - identifies the specific county location
0221 - identifies the specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV
Where:
AC - identifies the permit as an Air Construction Permit
AV - identifies the permit as a Title V Major Source Air Operation Permit
099 - identifies the specific county that project is located in
2222 - identifies the specific facility
001 - identifies the specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456
Where:
AC - identifies the permit as an Air Construction Permit
AO - identifies the permit as an Air Operation Permit
123456 - identifies the specific permit project

FPL MARTIN POWER PLANT - MARTIN COUNTY
Draft Permit No. 0850001-008-AC (PSD-FL-286)
New EUs 011 - 014: Addition of Two New Simple-Cycle Gas Turbines

1.0 EXISTING FACILITY

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

2.0 PROJECT DESCRIPTION

The applicant, Florida Power and Light, proposes to install two new simple cycle combustion turbines, two gas-fired natural gas fuel heaters, a common distillate oil storage tank, and associated equipment at the existing FPL Martin Power Plant. Each combustion turbine consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 60 feet tall and 22 feet in diameter. Each unit is designed to produce a nominal 170 MW of electrical power fired with natural gas as the primary fuel and low sulfur distillate oil as a backup fuel. The applicant proposes to limit use of the gas turbines as "peaking units" by restricting the allowable operation to no more than 3390 hours per year per unit. Of this total, no more than 500 hours per year would occur when firing low sulfur distillate oil as a backup fuel. In addition, the applicant requests approval for "power augmentation" and "peaking" as authorized high power modes of operation when firing natural gas. The high power modes result in higher CO and NOx emissions than those for normal gas firing and are discussed in more detail under the NOx BACT Determination. Of the allowable 3390 hours per year, no more than 500 hours per year would occur when operating in the high power modes. The applicant proposes dry low-NOx (DLN) combustion technology to control nitrogen oxide emissions and combustion design with clean fuels to minimize emissions of other pollutants.

As a result of fuel combustion, this project will emit emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of CO, NOx, PM/PM_{10}, and SO_2 exceed the Significant Emissions Rates established in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, the Department must establish emissions standards that represent a determination of Best Available Control Technology (BACT) for these pollutants. The permit will also include emissions standards for VOC as a PSD-synthetic minor pollutant. This document presents a detailed description of the PSD applicability analysis and BACT determination. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanied the Department's Intent to Issue Permit package.

An initial Intent to Issue Permit package was mailed to the applicant on May 5, 2000. The applicant requested several changes and provided additional supporting information. The primary changes were the addition of high temperature peaking for 60 hours per year, a reduction of power augmentation to 400 hours per year, revised stack dimensions, NOx compliance demonstrated with Acid Rain CEMS data, fuel consumption limits equivalent to hours of operation limits, addition of a particulate matter limit with testing, a visible emissions limit of 10% opacity for both gas and oil firing, and minor revisions to the maximum heat input and power output based on General Electric data. Revisions of the BACT determination are noted with the revision date.

3.0 PSD APPLICABILITY REVIEW

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program as approved by the EPA and defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with a National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. An existing facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and it falls under one of the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C.

The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because potential emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. For new projects at PSD major sources, each pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant in accordance with Rule 62-212.400, F.A.C. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to implement BACT for several "significant" regulated pollutants.

This project will be located in Martin County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The following table summarizes the potential emissions increases and PSD applicability for this new project based on information provided by the applicant.

Pollutant	Project Potential Emissions[a] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	Subject To BACT?
CO	170	100	Yes	Yes
NOx	423	40	Yes	Yes
PM	38	25	Yes	Yes
PM_{10}	38	15	Yes	Yes
SAM	5	7	No	No
SO_2	64	40	Yes	Yes
VOC	13	40	No	No

[a] - For each gas turbine, potential emissions were estimated by the applicant based on 2390 hours per year of normal gas firing, 500 hours per year of gas firing with high power mode, and 500 hours per year of distillate oil firing as a backup fuel. Potential emissions also include emissions from two gas fuel heaters and a distillate oil tank.

Therefore, the proposed combustion turbine project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM/PM_{10}, and SO_2.

4.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination and shall also give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants). The combustion turbine project is subject to 40 CFR 60, Subpart GG, a New Source Performance Standards (NSPS) which regulates Stationary Gas Turbines, adopted by reference in Rule 62-204.800, F.A.C. There are no applicable NESHAP regulations.

The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

5.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

For this project, the following pollutants are subject to a BACT determination: CO, NO_x, PM/PM_{10}, and SO_2. The applicant proposed control strategies for these pollutants in the PSD permit application. Besides the information submitted by the applicant, the Department also relied on the following information:

- The National Park Service made no adverse comments on the application;
- EPA Region 4 provided comments on the initial Draft Permit on May 19, 2000;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical product literature regarding DLN emissions and the gas turbine control system;
- Englehard equipment cost quotes for a CO oxidation catalyst and selective catalytic NO_x reduction;
- Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines (1993);
- Proposed AP-42 changes to Section 3.1 for gas turbines (10/96 draft and 5/98 revision);
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;
- Goal Line Environmental Technology Website: http://www.glet.com; and
- Catalytica Website – www.catalytica-inc.com

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. The following table provides a summary of the most recent determinations similar projects in the United States.

Brief Summary of Recent CO, NOx, and PM BACT Determinations for Similar Simple Cycle, Gas Fired Units

Project Location	Unit MW	Date	Technology	CO Limit ppmvd @ 15% O2	NOx Limit Ppmvd @ 15% O2	PM Limit	Comments
FPL Martin Plant, FL	170	04/00, D	DLN	9 15 w/PA	10, 3-hr CEMS 12 w/PA, 3-hr CEMS	5% Opacity	500 hr/yr oil firing 500 hr/yr PA mode
Palmetto Power, FL	170 MW WH 501FD	03/00, D	DLN	Initial: 25 (12 months) Final: 15	15, 3-hr CEMS	10% opacity	No oil firing
Desoto Power, FL	170 MW GE 7FA	03/00, D	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Shady Hills Pasco, FL	170 MW GE 7FA	01/00, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Vandolah Hardee, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Oleander Brevard, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
JEA Baldwin, FL	170 MW GE 7FA	10/99, P	DLN	12	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Reliant Osceola, FL	170 MW GE 7FA	11/99, P	DLN	10.5	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
TEC Polk Power, FL	165 MW GE 7FA	10/99, P	DLN	15	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Dynegy Heard, GA	170 MW WH 501F	10/99, P	DLN	25	15	10% opacity	No oil firing
Tenaska Heard, GA	170 MW GE 7FA	12/98, P	DLN	15	15	Unknown	720 hr/yr oil firing
Calvert City, KY	170 MW GE 7FA	1999, D	WI	30, base load 90, other	25	Unknown	? hr/yr oil firing
Mid-GA Cogen	119 MW WH 501D5A	06/98, O	DLN, SCR	10	9	18 lb/hr	? hr/yr oil firing
Dynegy Reidsville, NC	180 MW WH 501F	06/99, P	DLN	25	Initial: 25 Final: 15 (by 2002)	6 lb/hr	1000 hr/yr oil firing
Lyondell Harris, TX	160 MW WH 501F	11/99, P	DLN	25	25	Unknown	No oil firing
Southern Energy, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
RockGen Cristiana, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
Lakeland, FL	250 MW WH 501G	07/98, P	DLN, HSCR	25	Initial: 25 Final: 9 (by 2002)	10% opacity	250 hr/yr oil firing

Abbreviations:

Manufacturer	Date	Controls	Other
GE – General Electric	D – Draft	DLN – Dry Low-NOx	LAER – Lowest Achievable Emission Rate
WH – Westinghouse	O – Operating	HSCR – Hot Selective Catalytic Reduction	CEMS – Continuous Emissions Monitoring System
ABB – Asea Brown Boyan	P – Permitted	SCR - Selective Catalytic Reduction	PA – Power Augmentation (Steam Injection)
		WI = Water or Steam Injection	

Notes: All data presented is for > 100 MW simple cycle units firing natural gas. The Lakeland project is permitted for combined cycle operation with separate limits for simple cycle mode. The remaining projects are restricted to intermittent simple cycle operation.

5.1 NITROGEN OXIDES (NOX)

{Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NOx Emissions from Stationary Gas Turbines. Specific project information is included where applicable.}

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures associated with combustion turbines, the primary pollutant of concern is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @ 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions in the range of 150 ppmvd @ 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from stationary gas turbines is 75 ppmvd corrected to 15% oxygen and ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically-bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures due to the inherently lower thermal NOx portion. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Most new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to 100% of base load. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, usually less than 32° F.

<u>Identification of Control Technologies</u>

The following technologies were identified as potentially applicable for the control of NOx from combustion turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd @15% O_2.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the

same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for dry low-NOx combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%. DLN technology research for oil firing continues.

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850°F. SCR is a commercially available, demonstrated control technology currently employed on several combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd) with control efficiencies up to 98%.

"Hot" Selective Catalytic Reduction (SCR): Due to temperature limitations of conventional SCR catalysts, vendors have developed specially formulated catalysts designed to further the reduction reaction at temperatures up to 1025°F. Also, cooling air can be added to reduce the gas temperatures to the appropriate design range. Hot SCR can deliver NOx control efficiencies of 70% to 95%.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For boilers, SNCR has achieved control efficiencies in the 40% to 60% range.

Non-Selective Catalytic Reduction (NSCR): NSCR uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor in exhaust gas streams containing less than 3% oxygen. This technology has only been applied to automobiles and stationary reciprocating engines with variable control efficiencies.

SCONOx™: This technology is a NOx and CO control system offered by Goal Line Environmental Technologies and ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. The required operating

temperature range is between 300°F and 700°F which requires a HRSG for use with a gas turbine. SCONOx™ can achieve control efficiencies in the 90% to98% range.

XONON™: This is an emerging technology that partially burns fuel in a low temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature and NOx formation followed by flame-less catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but will be specific to each manufacturer and model of gas turbine. It is anticipated that control efficiencies will be in the 80% to 95% range.

Applicant's Proposed NOx Controls

For a simple cycle gas turbine, the applicant recognized "hot" selective catalytic reduction as the top control option followed by dry low-NOx (DLN) combustion technology and water injection. For this project, General Electric guaranteed NOx emissions of 9 ppmvd @ 15% oxygen with DLN technology for gas firing and 42 ppmvd @ 15% oxygen for oil firing with water injection. The applicant estimated that hot SCR could reduce these emissions rates to 4 ppmvd @ 15% oxygen for gas firing with DLN and 16 ppmvd @ 15% oxygen for oil firing with water injection. However, the applicant makes the following claims regarding additional adverse impacts.

Energy Impacts: Hot SCR would result in a pressure loss across the catalyst resulting in an energy penalty of approximately 0.5%. Significant energy costs are associated with operating the hot SCR system. The lost energy would be equivalent to 370,000 mmBTU per year or about 37 mmCF per year of natural gas.

Environmental Impacts: The maximum predicted NOx concentrations resulting from DLN technology are well below the PSD increment of 25 ug/m^3 (annual average), the AAQS of 100 ug/m^3 and less than 20% of the significant impact level. Additional NOx reduction from requiring hot SCR would not be significant. Hot SCR would generate additional emissions of ammonia (> 47.7 tons per year per unit) and ammonium sulfates (>6.6 tons per year per unit). Power lost to the hot SCR system would have to be generated by other less efficient units resulting in increased emissions. CO_2 emissions would greatly increase as a result of hot SCR. Spent catalyst may have to be handled and treated as hazardous wastes. Ammonia handling and storage involves inherent risks and safety issues.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of hot SCR would result in capital costs of $5,189,813 and annualized costs of $1,640,906 per year. The applicant assumed a hot SCR system would remove an additional 127 tons of NOx per year (4 ppmvd @ 15% O_2 and 61% control efficiency) over a DLN only system at 10.5 ppmvd @15% O_2. This resulted in an incremental cost effectiveness for hot SCR of $12,943 per ton of NOx removed.

The applicant rejected hot SCR primarily based on unreasonable costs associated with controlling the low available tonnage of NOx emissions available from this project. This is primarily due to the inherently low emissions of the General Electric Model PG7241(FA) gas turbine as well as the applicant's request to restrict operation to that of a peaking unit (3390 hours per year). Therefore, the applicant proposed the following NOx limit as BACT for this project:

Applicant's Proposed NOx BACT

Normal Gas Firing Mode: 10.5 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 42.0 ppmvd @ 15% O_2 achieved by water injection

The applicant concludes by stating that DLN combustion provides the most cost effective alternative, is pollution preventing, results in low ambient impacts, and is consistent with recent BACT determinations for similar simple cycle combustion turbines made by Florida and other states.

Department's NOx BACT Determination (Revised 06/06/00)

The Department rejected several previously mentioned control options for the following reasons.

- *Conventional Selective Catalytic Reduction (SCR)* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (850° F) for this technology.
- *Selective Non-Catalytic Reduction (SNCR)* was rejected because the gas turbine exhaust temperature of 1100°F is below the design limit (1600° F) for this technology.
- *Non-Selective Catalytic Reduction (NSCR)* was rejected because the oxygen content of the combustion turbine exhaust (13% to 15%) is above the design limit (3%) for this technology.
- *SCONOx™* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (700° F) for new technology.
- *XONON™* because this emerging technology is model-specific and not yet commercially available for the General Electric Model PG7241(FA).

The Department also recognizes hot selective catalytic reduction (hot SCR) combined with dry low-NOx (DLN) combustion technology as the top control option followed DLN technology alone, and water injection for oil firing. However, the Department disagrees with several of the applicant's statements regarding adverse impacts.

Energy Impacts: Installation of hot SCR *would* result in a total energy penalty of approximately 0.5% mostly due to the pressure drop across the catalyst bed. For SCR systems, EPA (1993) bases energy consumption to operate the SCR system on the pressure drop, neglecting other energy costs.

Environmental Impacts: The Department gives no consideration to the applicant's comment that there is no environmental benefit from add-on controls because NOx levels are already below the PSD increments, significant impact levels and AAQS. Ambient impacts from the project are only considered in the air quality analysis and carry no weight in making a BACT determination. Hot SCR would result in some ammonia "slip" or emissions of unreacted ammonia. However, estimating ammonia, ammonia sulfate, and PM_{10} emissions based on 9-10 ppm is misleading. Manufacturers of SCR systems typically design and guarantee systems with a 9 to 10 ppm of ammonia slip, but this is based on the end of the catalyst life and is not representative of actual emissions. An operator would attempt to reduce ammonia slip whenever possible to reduce operating costs. Storage and handling of ammonia does present additional risks, but these risks can be safely managed as evidenced by the numerous existing SCR systems, industrial ammonia refrigeration systems, fertilizer plants, etc.

Economic Impacts: In general, the Department agrees that adding hot SCR to the General Electric Model PG7241(FA) gas turbine with DLN controls would result in a cost effectiveness in the range of $10,000 to $13,000 per ton of NOx removed. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also recognizes that the analysis is significantly influenced by three critical constraints: the applicant's request for simple cycle operation only, the applicant's request for restricted operation as peaking units (3390 hours per year per gas turbine), and the inherently low emissions of the General Electric Model PG7241(FA) gas turbine. Should the applicant ever request operation of these gas turbines as base load units, conversion to combined cycle operation, or the substitution of a another gas turbine model, it is essential that the NOx BACT determination be reevaluated.

Based on the above discussion, the Department also rejects hot SCR as not cost effective for the project as limited by the applicant's requests. Therefore, the dry low-NOx combustion technology designed into the General Electric Model PG7241(FA) is determined to represent the best available control technology for this project. Dry low NOx combustion is pollution preventing in nature, avoids emissions of several non-regulated pollutants such as ammonia, and is consistent with recent BACT determinations made in Florida and other states.

The Department evaluated the applicant's request for two "high power modes" of operation when firing natural gas, which included steam injection for power augmentation and raising the combustion reference temperature for additional peaking power. The high power modes can result in NOx emissions that are higher than the normal gas-firing mode. Initially, the Department accepted the request for limited steam injection, but rejected the request for high temperature peaking primarily due to the high number of operating hours requested, and the potential for degradation of the unit. However, as part of the request for a revised Draft Permit, the applicant provided additional information from General Electric regarding the emissions performance and adjustments made by the automated gas turbine control system to achieve high temperature peaking. Also, the applicant reduced the request for peaking to 60 hours per year and power augmentation to 400 hours per year, which results in no increase in annual emissions. High temperature peaking is expected to result in lower CO and VOC emissions.

After consideration of the new information provided, the Department establishes the following NOx standards as BACT for this project:

NOx BACT Determination

Normal Gas Firing: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average (to ensure that the units remain tuned for maximum NOx reduction). NOx emissions shall also not exceed 10.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (The slightly higher continuous emissions limit with a short-term average was established to compensate for operation as a peaking unit. The mass emissions limit will be based on 10 ppmvd @15% O_2 and the most recent projects for the Model PG7241(FA) gas turbine.)

Gas Firing With Power Augmentation: 12.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the power augmentation mode to allow maximum power generation during the hot summer months of high demand. Operation in this mode will be restricted to no more than 400 hours per year.)

Gas Firing With Peaking: 15.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the peaking mode to provide limited short-term peaking power. Operation in this mode will be restricted to no more than 60 hours per year.)

Distillate Oil Firing: 42.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by water injection. (DLN combustion technology is ineffective when firing distillate oil as a backup fuel. Operation when oil firing with water injection will be restricted to no more than 500 hours per year.)

Corresponding mass emission limits will also be established for each method of operation. The Department will include specific conditions in the permit to address the following items:

- Each combustion turbine shall operate only in simple cycle mode. Conversion to combined cycle operation will require a permit modification.
- Each combustion turbine shall operate no more than 3390 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not fire oil for more than 500 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not operate in the power augmentation mode for more than 400 hours during any consecutive 12 months. Alternatively, the Department may establish equivalent amounts of fuel consumption limits based on the maximum heat inputs at a compressor inlet air temperature of 59° F, which was the basis of the potential emissions for this project. To relax any of these conditions will require a permit modification.
- Each combustion turbine shall operate below 50% base load for no more than two hours per day.

This BACT determination is much more stringent than the standards of NSPS, Subpart GG. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. In addition, the permittee shall install, calibrate, operate, and maintain a certified NOx continuous emissions monitor (CEMS) to demonstrate continuous compliance with the BACT limits.

5.2 CARBON MONOXIDE (CO)

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion while operating the combustion turbine. In general, CO emissions are inversely proportional to NOx emissions for gas turbines. However, new advanced combustor designs have also been able to lower CO emissions concurrently with NOx emissions. It is noted that General Electric has guaranteed CO emissions performance for the Model PG7241(FA) at 9.0 ppmvd @ 15% O_2 for several projects.

Applicant's Proposed CO BACT

The applicant identified two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and efficient combustor design. An oxidation catalyst consists of a noble metal catalyst section incorporated into the combustion turbine exhaust. The catalyst promotes oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than under normal conditions. The control efficiency is primarily a function of gas residence time and can exceed 90%. For this project, the exhaust gas temperature of 1100°F is in the proper design range. The applicant recognized an oxidation catalyst as the top control. However, the applicant asserts that an oxidation catalyst would result in the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of approximately 2 inches of water column. The lost energy is equivalent to approximately 11,000 mmBTU per year.

Environmental Impacts: The air quality impacts of a DLN system are well below the significant impact levels for CO. There is no additional environmental benefit gained by installing an oxidation catalyst. The air quality impacts of a DLN system alone are well below the PSD significant levels and less than 0.1% of the AAQS.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of an oxidation catalyst would result in capital cost of $1,673,295 per unit. The annualized cost was estimated to be $561,759 per year. It was assumed that the catalytic system could remove an additional 74 tons of CO per year (90% control efficiency) over a DLN only system at 12 ppmvd @ 15% O_2. This results in a cost effectiveness for the oxidation catalyst of $7595 per ton of CO removed. No such costs would be associated with the efficient combustion of the Model PG7241(FA) gas turbine.

The applicant rejected the oxidation catalyst as not being cost effective and not producing any measurable reductions in air quality impacts. The applicant proposed the following as the best available controls:

Applicant's Proposed CO BACT

Normal Gas Firing Mode: 12.0 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 20.0 ppmvd @ 15% O_2 achieved by water injection

Department's CO BACT Determination

The Department also recognizes an oxidation catalyst as the top control for CO emissions. However, the Department disagrees with many of the applicant's assumptions as summarized below.

Energy Impacts: The Department agrees that installation of an oxidation catalyst *would* result in an energy penalty due to the pressure drop across the catalyst.

Environmental Impacts: The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination.

Economic Impacts: In general, the Department agrees that the addition of an oxidation catalyst would result in a cost effectiveness in the range of $6000 to $8000. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, and energy consumption. Similar to the discussion for NOx controls, the Department recognizes that the cost analysis has been significantly constrained for this project by the applicant's requested operation.

The Department also rejects the addition of an oxidation catalyst as not being cost effective for the project as limited by the applicant's requests. Therefore, the Department establishes the following CO standards as BACT for this project:

CO BACT Determination

Gas Firing, Normal and Peaking: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Gas Firing With Power Augmentation: 15.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Distillate Oil Firing: 20.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by water injection.

Corresponding mass emission limits will also be established for each mode of operation. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. The Department will include the specific conditions identified under NOx controls to ensure that a switch to based loaded units, conversion to combined cycle operation, or substitution with a different make or model of gas turbine will trigger the appropriate permitting actions.

5.3 PARTICULATE MATTER (PM/PM_{10}) AND SULFUR DIOXIDE (SO_2)

Discussion of PM, PM_{10} and SO_2 Emissions

Emissions of particulate matter and sulfur dioxide will result from the combustion of the natural gas and low sulfur distillate fuel. Limited testing indicates that most of the particulate matter emitted from the combustion turbine will be less than 10 microns in diameter (PM_{10}). Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants.

Applicant's Proposed PM, PM_{10}, and SO_2 BACT

The applicant indicated that a review of the EPA RACT/BACT/LAER Clearinghouse did not reveal any post-combustion controls were required for any gas/oil fired combustion turbine projects. Uncontrolled particulate matter emissions are estimated to be less than 0.01 grain per dscf of exhaust gas, which is typically specified as controlled emissions from a baghouse. The use of natural gas as the primary fuel and the restricted use (500 hours per year or less) of very low sulfur (0.05% sulfur by weight or less) distillate oil will result in very low emissions of SO_2.

Applicant's Proposal for PM, PM_{10}, and SO_2 BACT

Each combustion turbine shall be fired primarily with pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF. Low sulfur distillate oil containing no more than 0.05% sulfur by weight shall be fired only as a backup fuel for no more than 500 hours per year.

The applicant indicated that recent BACT determinations for large combustion turbine projects specified such clean fuels as BACT.

Department's PM, PM_{10}, and SO_2 BACT Determination (Revised 06/06/00)

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. Similarly, there are scrubbers available to further reduce SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas as the primary fuel and to fire a restricted amount of very low sulfur distillate oil as the backup fuel. The Department agrees that further control of particulate matter and sulfur dioxide emissions with one of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case. In addition, a fuel specification for sulfur limits the maximum potential emissions that the gas turbine could emit. The Department establishes the following work practice standards as BACT for PM, PM_{10}, and SO_2.

PM, PM_{10}, and SO_2 BACT

EPA Region 4 commented that the BACT standard for particulate matter should include a mass emissions limit and at least an initial test. The applicant requested that the visible emissions rate for gas firing with the dual fueled combustion be raised to 10%. At this time, the Department is unable to adequately document that the measurement of particulate matter emissions from large gas turbines is technically infeasible. Therefore, the Department revised the initial Draft Permit to include the following standards.

Particulate Matter. When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load. The permittee shall demonstrate compliance by conducting tests in accordance with EPA Method 5 (or 17, if applicable).

Fuel Specifications. Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. Because the maximum potential SO_2 emissions are limited by the fuel sulfur specification, no emissions performance testing will be required. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit.

VE Standard. When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit.

5.4 PSD SYNTHETIC MINOR LIMITS

Volatile Organic Compounds: VOC emissions result from incomplete combustion when firing natural gas and low sulfur distillate fuel oil. Large combustion turbines such as the Model PG7241(PA) offer high temperatures with very efficient combustion resulting in low levels of volatile organic compounds. Therefore, the Department establishes the following standards as PSD synthetic minor limits for VOC:

Gas Firing, All Modes: 1.5 ppmvw

Oil Firing, Backup Fuel: 3.0 ppmvw

Corresponding mass emission limits will also be established for each mode of operation. These standards limit the potential annual emissions of VOC to less than the Significant Emission Rate of 40 tons per year. Initial compliance with the VOC emissions standard shall be demonstrated by conducting performance tests in accordance with EPA Methods 25 or 25A. EPA Method 18 may be used as an optional method to account for the non-regulated methane fraction of the measured VOC emissions. Compliance shall also be demonstrated during the fiscal year prior to renewing each operation permit.

6.0 OTHER EMISSIONS UNITS

6.1 TWO NATURAL GAS FUEL HEATERS

Each fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas. For continuous operation, total emissions of PM/PM_{10}, SO_2 and VOC are each less than 1 ton per year and emissions of CO and NOx are each less than 10 tons per year. These emissions represent much less than 3% of the total controlled emissions for this project. For these small emissions units, the Department determines that efficient combustion and the firing of natural gas to be BACT.

6.2 OIL STORAGE TANK

A common storage tank (2.1 million gallon) supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbines Nos. 8A and 8B. Because VOC emissions are estimated to be less than 1 ton per year, the Department determines BACT to be the storage of only distillate fuel oil in this tank and compliance with NSPS Subpart Kb which requires the permittee to keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. These records shall be retained for the life of the facility.

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

The following table summarizes the BACT standards determined by the Department for this project. Similar limits will be specified as conditions of the permit.

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
BACT Emission Standard			
CO	Gas, Normal And Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests

		12.0 ppmvd @ 15% O2, 3-hr CEMS avg.	All loads, certified CEM data
	Gas W/Peaking	15.0 ppmvd @ 15% O2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg. 15.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Peak load; initial/renewal tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Base load; initial and annual tests All loads, certified CEM data
SO_2, PM/PM_{10}	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
Synthetic Minor Emission Standard			
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits

Note: PA means "power augmentation". The mass emission limits were based on 100% base load, maximum heat input, the fuel higher heating values, compressor inlet conditions of 35° F and 20% RH for normal gas and oil firing, and compressor inlet conditions of 80-95° F and 60% RH for gas firing with power augmentation.

According to the applicant, emissions data from General Electric was, "*... adjusted to reflect degradation when the units operate over time and performance improvements beyond that provided for by the manufacturer's guarantee.*" To account for this overall "degradation", the applicant increased the mass flow rate through the turbine by approximately 11%. This resulted in higher fuel consumption and predicted mass emission rates. However, the Department has reviewed many projects for peaking units as well as projects with power augmentation. The Department believes it is inappropriate to permit emissions increases that result from an applicant's choice to operate under conditions that will significantly degrade the unit such that the manufacturer will no longer guarantee emissions or performance. Therefore, the Department developed mass emission limits based on General Electric's maximum emissions performance estimates, similar limits in recent Department permits for the Model PG7241(FA) gas turbine, and the following conditions:

- For normal gas firing and backup oil firing, mass emission limits were based on operation at base load with a compressor inlet air temperature of 35° F.
- For gas firing with power augmentation, mass emissions limits were based on operation at base load with a compressor inlet air temperature of 95° F for NOx, and a compressor inlet temperature of 80° F for CO (worst-case scenarios).
- Information provided by the applicant did not suggest that the gas turbine would have problems complying with GE's guaranteed CO emissions level of 9 ppmvd @ 15% O_2 for normal gas firing.
- For normal gas firing, General Electric data indicates NOx emissions of 61 lb/hour (9 ppmvd @ 15% O_2) at 35° F. The Department allowed 10 ppmvd @ 15% O_2 with compliance demonstrated by CEMS data on a 3-hour block average as opposed to other Department permits containing long-term 24-hour block averages. The Department believes the slightly higher limit combined with the shorter averaging period better defines peaking operation. To account for the increase, the Department considered the following items in establishing the NOx mass emissions limit: the GE mass emission rate at 59° F is 59 lb/hour; the GE mass emission rate at 35° F is 61 lb/hour; and the mass emission limit for the recent Desoto Power project was 64 lb/hour.

The application indicates that recently issued PSD permits specify emissions limits similar to those requested by the applicant. In support of the Department's BACT determination, the following tables offer a comparison of the Department's emissions limits, the applicant's proposed emission limits, and the emission limits specified for a recent similar project (Desoto Power) consisting of General Electric Model PG7241(FA) gas turbines.

Comparison of FPL Martin With Desoto Power

Emissions Per Unit - Gas/Oil Firing

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	67	82	86
NOx	183	208	252
PM/PM_{10}	17	19	20
SAM	< 3	< 3	4
SO_2	33	32	55
VOC	6	6	11

Emissions Per Unit - Gas Only (Including High Power Modes)

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	56	79	72
NOx	113	144	109
PM/PM_{10}	15	17	17
SAM	< 1	< 1	< 1
SO_2	9	9	8
VOC	5	5	5

Comments:

It should be noted that the Desoto Power project allows up to 3390 hours per year of operation with no more than 1000 hours per year of oil firing. The higher emissions are the result of the increased oil firing. In addition, the Desoto Power project also allows up to 12 ppmvd of CO emissions, but did not permit power augmentation.

The gas only case is presented as more typical of actual operations. The Department's draft permit for the proposed FPL Martin project results in approximately 7 tons of NOx per year more than the Desoto Power project. About half of this is the result of limited power augmentation and about half from the slightly higher hourly emission limit. Lower CO emissions are the result of the 9 ppmvd limit established for the FPL Martin project compared to the 12 ppmvd limit specified for the Desoto Power project.

7.2 BACT EXCESS EMISSIONS ALLOWED

1. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

2. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

   (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

   (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

   (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

   (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

[Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

8.0 RECOMMENDATION AND APPROVAL

The permit project engineer is Jeff Koerner. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer at 850/414-7268 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, P.E., Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

SECTION IV.

APPENDIX E - EMISSIONS STANDARDS SUMMARY

For informational purposes only, the following table summarizes the emissions standards specified in this permit. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines (8A and 8B)

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal and Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O_2, 3-hr avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O_2, 3-hr avg.	Peak load; initial and annual tests All loads, certified CEM data
	Gas, Peaking	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg. 15.0 ppmvd @ 15% O_2, 3-hr avg.	Peak load; initial/renewal tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr avg.	Base load; initial and annual tests All loads, certified CEM data
PM/PM_{10}, SO_2	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests

Note: The mass emission limits for were based on the following:

- Gas Firing, Normal: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW.
- Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW.
- Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW.
- *Distillate Oil*: At a compressor inlet air temperature of 35° F and firing 2000 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW.

Note: All heat input values are based on the higher heating values (HHV) of the fuels.

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

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

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

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

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

(b) Determination of Prevention of Significant Deterioration (X); and

(c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

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

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

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

SECTION IV.

APPENDIX GG - NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, Subpart A, General Provisions, including:

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

This emissions unit is subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. The following conditions follow the original NSPS rule language and numbering scheme. Regulations that are not applicable were omitted for clarity. Because this emissions units is subject to an NSPS, it is also subject to the following federal provisions: 40 CFR 60, Subpart A, General Provisions for sources subject to an NSPS, adopted by reference in Rule 62-204.800(7)(d), F.A.C.; 40 CFR 60, Appendix A - Test Methods, Appendix B - Performance Specifications, Appendix C - Determination of Emission Rate Change, Appendix D - Required Emissions Inventory Information, Appendix F - Quality Assurance Procedures, adopted by reference in Rule 62-204.800(7)(e).

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10 million BTU per hour, based on the lower heating value of the fuel fired.

40 CFR 60.331 DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

60.332 STANDARD FOR NITROGEN OXIDES.

(a) On and after the date of the performance test required by Sec. 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b) of this section shall comply with one of the following, except as provided in paragraphs (e) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

Where:

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

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

F = NO emission allowance for fuel-bound nitrogen as defined in the following table:

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (Percent By Weight)	"F" (NOx Percent By Volume)
$N < 0.015$	0
$0.015 < N < 0.1$	0.04(N)
$0.1 < N < 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

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

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 100 million Btu per hour based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(f) Stationary gas turbines using water or steam injection for control of NOx emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

On and after the date on which the performance test required to be conducted by Sec. 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

40 CFR 60.334 MONITORING OF OPERATIONS.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within +/- 5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under Sec. 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with Sec. 60.332 by the performance test required in Sec. 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in Sec. 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under Sec. 60.335(a).

(2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) Ice fog. Each period during which an exemption provided in Sec. 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be

reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR 60.335 TEST METHODS AND PROCEDURES.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in Sec. 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Secs. 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)(P_r/P_o)^{0.5}(e^{19(H_o - 0.00633)})(288°K/T_a)^{1.53}$$

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

H_o = observed humidity of ambient air, g H_2O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

(2) The monitoring device of Sec. 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Sec. 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference--see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some

fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

(e) To meet the requirements of Sec. 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT
FIGURE 1 – QUARTERLY PERFORMANCE SUMMARY REPORT
GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEMS

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NOx TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer and Model No.: ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____________________

Total source operating time in reporting period [a]: ____________________

Emission data summary [a]		**CMS performance summary** [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Title

____________________ ____________________
Signature *Date*

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief – Bureau of Air Regulation

THROUGH Al Linero, Administrator - New Source Review Section

FROM: Jeff Koerner, Project Engineer - New Source Review Section JK

DATE: June 9, 2000

SUBJECT: FPL Martin Plant – Revised Draft Permit
Two Nominal 170 MW Simple Cycle Peaking Combustion Turbines (PSD-FL-286)

Attached is the public notice package to install two new 170 MW simple cycle gas turbines at FPL's existing power plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. Each unit is a General Electric Model PG7241(FA) gas turbine-electrical generator set capable of producing a nominal 170 MW of electricity. Completion of this project will result in a nominal production capacity of 2940 MW for the existing power plant. This is a revision of the Draft Permit previously issued on May 5, 2000.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. Each unit will be restricted to fuel consumption limits equivalent to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for power augmentation and high temperature peaking during high demand periods, typically summer. Power augmentation (PA) is limited to 400 hours per year and only when firing natural gas. High temperature peaking is limited to 60 hours per year and only when firing natural gas. CO and NOx emissions are higher during these alternate methods of operation. The draft permit includes the following BACT standards.

CO Emissions: Achieved by the efficient combustion of clean fuels

- Gas Firing, Normal and Peaking: 9.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
- Gas Firing W/PA: 15.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
- Distillate Oil Firing: 20.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test

NOx Emissions: Achieved by dry low-NOx combustion for gas firing and water injection for oil firing

- Gas Firing, Normal: 9.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
  10.0 ppmvd @ to 15% O_2 based on a 3-hour average, CEMS data
- Gas Firing W/PA: 12.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data
- Gas Firing W/Peaking: 15.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data
- Distillate Oil Firing: 42.0 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data

PM/PM_{10} and SO_2 Emissions: Achieved by the efficient combustion of clean fuels

- Particulate Matter: ≤ 9.0 lb/hour when firing gas and ≤ 17.0 lb/hr when firing oil, initial and renewal tests
- Firing natural gas as the primary fuel and distillate oil as a backup fuel containing ≤ 0.05% sulfur by weight
- Visible emissions ≤ 10% opacity when firing natural gas or oil, annual test

VOC Emissions: Very low emissions do not trigger a BACT determination for this project

Excess Emissions: Operation below 50% of base load shall not exceed 120 minutes per day. During periods of startup and shutdown, visible emissions are limited to 20% opacity for up to ten, 6-minute observation periods per day. NOx emissions must be recorded during startup, shutdown, and malfunction, but the permittee may exclude two 1-hour CEMS averages per day due to excess emissions resulting from these conditions.

The permitting time clock has been stopped by the issuance of the first Draft Permit. We will withdraw the first Draft Permit and replace it with this revised Draft Permit. This project is also a "fast-track modification" of the power plant siting certification. I recommend your approval of the attached Intent to Issue package for this project.

JFK
Attachments

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT (REVISED DRAFT PERMIT)

PERMITTEE

Florida Power and Light – Martin Plant
P.O. Box 176
Indiantown, FL 34956

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911

PROJECT DESCRIPTION

The revised draft permit authorizes installation of two new 170 MW simple cycle combustion turbines at FPL's existing power plant located in Martin County. Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set capable of producing a nominal 170 MW of electricity. Each peaking unit will be fired primarily with natural gas and restricted to a fuel consumption limit equivalent to 3390 hours per consecutive 12 months. Of this total, no more than 500 hours may occur when firing low sulfur distillate oil as a backup fuel. The draft permit authorizes steam injection for power augmentation (PA, 400 hours per year) and high temperature peaking (60 hours per year) to accommodate summer peaking demands. Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I Area (Everglades National Park) and Class II areas. The initial Draft Permit was issued on May 5, 2000. The applicant requested several substantial changes and provided supporting information. The Revised Draft Permit includes the following BACT standards.

CO emissions will be achieved by the efficient combustion design and shall not exceed: 9 ppmvd @ 15% O_2 for normal gas firing and peaking (test); 15 ppmvd @ 15% O_2 for gas firing w/PA (test); and 20 ppmvd @ 15% O_2 for oil firing (test).

NOx emissions will be achieved by dry low-NOx combustion for gas firing, water injection for oil firing and shall not exceed: 9 ppmvd @ 15% O_2 for gas firing (test); 10 ppmvd @ 15% O_2 for gas firing (CEMS); 12 ppmvd @ 15% O_2 for gas firing w/PA (test and CEMS); 15 ppmvd @ 15% O_2 for gas firing w/peaking (test and CEMS); and 42 ppmvd @ 15% O_2 for oil firing (test and CEMS).

PM/PM_{10} and SO_2 emissions will be achieved by efficient combustion, the firing of natural gas as the primary fuel and the firing of distillate oil containing less than 0.05% sulfur by weight as a backup fuel. PM is limited to 9.0 lb/hr for gas firing and 17.0 lb/hr for oil firing. Opacity is limited to 10% or less when firing natural gas or distillate oil.

VOC emissions will be minimized by the use of clean fuels and efficient combustion. The inherently low VOC emissions did not trigger a BACT determination for this project.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery F. Koerner

6-9-00

Jeffery F. Koerner, P.E.
Registration Number: 49441

Date

New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection

"More Protection, Less Process"

INTEROFFICE MEMORANDUM

Date: 06-Jun-2000 01:05pm
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

To: Jeff.Koerner (Jeff.Koerner@dep.state.fl.us)

Subject: Martin Modeling

Jeff,

I spoke with Steve Marks at Golder today regarding the revised stack dimenstions. He's rerun the
model and the impacts are much the same as before. He's been trying to reach Cleve Holladay,
but as of this morning had been unsuccessful.

I'm sure they'll hook up within a day or so and resolve this.

I received your revised permit and am in the process of reviewing. Will be in touch as soon as I
can....hopefully tomorrow if things go the way I want them to.

I really appreciate all the fine work you've done on this.

Regards....

- Rich

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

RECEIVED
JUN 06 2000
BUREAU OF AIR REGULATION

June 5, 2000

9937614A

Jeffery F. Koerner, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Dr., Suite 4
Tallahassee, Florida 32301

RE: Environmental Protection Agency (EPA) Comments
DEP File No. 0850001-001-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Jeff:

This correspondence provides the additional information requested by the Department concerning EPA Region IV's comments on the FPL's Martin Peaking Project. The primary comment that the Department requested information on was related to formaldehyde emissions (i.e., paragraph 1. of the EPA letter). The information requested follows:

1. EPA Comment - We suggest you verify the emission rate used by Golder Associates to estimate potential formaldehyde emissions. The emission factor cited by Golder is only one-fifth of the emission factor cited for formaldehyde from natural gas turbines in the recently revised section 3.1 of AP-42. Additionally, the emission factor used by Golder (cited as "Golder Associates, 2000") is not included in the reference section of the application. A complete reference for this emission factor should be provided by Golder along with an explanation for why this emission factor is more appropriate than the emission factor from AP-42.

   Additional Information - Golder Associates has reviewed the emission factor originally used to estimate formaldehyde in light of the latest AP-42 emission factor recently published as well as the EPA Gas Turbine Data Base used to develop the latest AP-42 emission factors.

   The original emission factor used by Golder Associates in the application was from the Electric Power Research Institute (EPRI) sponsored Electric Utility Trace Substances Synthesis Report. This report was submitted to EPA as part of the requirements of the 1990 Clean Air Act Amendments to study potentially toxic air pollutants from utility sources. Since there was a lack of data available for formaldehyde for large turbines, Golder Associates used the EPRI data. This data is the most technically accurate and complete data available on emissions from utility sources. The emission factor used for the Martin Peaking Units was 34 lb/10^{12} Btu. It should be recognized that there is still limited data on formaldehyde emissions from large (i.e., > 100 MW) gas turbines.

The recent EPA emission factor suggests formaldehyde emissions from gas turbines of 780 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent and 230 lb/10^{12} Btu when firing distillate oil. The EPA suggested emission factor for all loads is 3,100 lb/10^{12} Btu. Since the FPL Martin Peaking Units will fire primarily natural gas, with limited oil firing, the worst case annual emissions would be from natural gas firing. Using the EPA AP-42 emission factor the estimated emissions are 2.35 tons/year/turbine (based on 3,390 hours/year, ISO turbine inlet and 1,776 mmBtu/hr – HHV). Using the EPA suggested emission factor for all loads would produce a calculated emission of 9.3 tons/year/turbine or 18.6 tons/year for the project. Golder Associates believes the emission factors are not appropriate for the General Electric Frame 7FA combustion turbine based on several factors. First, and most importantly, the data used to develop the AP-42 emission factors is not representative of the General Electric Frame 7FA combustion turbine. Second, a review of the data of the pertinent information in the EPA database that relates to the characteristics clearly suggests a much lower emission factor for formaldehyde. Some of the important aspects of the EPA Gas Turbine Database related to formaldehyde emission are as follows.

- The formaldehyde emissions are from small (< 30 MW) gas turbines. The available data is from an average capacity of about 28 MW. More importantly, the median capacity, or the turbine size where an equal number of turbines are above and below that size, is about 15 MW. Data from only 8 large turbines (>30 MW) is included in the EPA database, with a maximum size of 88 MW.
- In contrast to the AP-42 emission factors for formaldehyde which are based on averages, the median values are substantially lower. For all loads, the median formaldehyde emissions are about 320 lb/10^{12} Btu; for turbine loads greater than 50 percent the median emissions are about 110 lb/10^{12} Btu. Being a factor of 8 to 10 times lower than the average factor clearly points to the great range in the emissions of formaldehyde and how the individual turbine combustion characteristics can influence the results.
- There is a strong relationship between formaldehyde and CO emissions, as noted by EPA in the support document and, and as observed in the data. Gas turbines with higher CO emissions had higher observed formaldehyde emissions. An evaluation of the coincident CO and formaldehyde data indicates that formaldehyde emissions were 150 lb/10^{12} Btu when the CO emissions were 0.02 lb/mmBtu or less. The CO emission for the GE Frame 7FA is guaranteed to be 9 ppmvd or less at all purposed operating loads, which is equivalent to 0.016 lb/mmBtu.

There are no confirmed test data of formaldehyde emissions from a GE Frame 7FA. Golder Associates has been made aware of data obtained in the mid-1990s on an early version of the Frame 7FA with Dry Low-NO_X combustors. The test reported about 260 lb formaldehyde/10^{12} Btu. While this data cannot be verified or relied on as an emission factor, the formaldehyde emissions were within the median of all turbine data and within the formaldehyde for turbines with CO emissions equal to or less than 0.02 lb/mmBtu.

A review and evaluation of the EPA data base suggest that formaldehyde emissions from the GE Frame 7FA will be much less than the average AP-42 emission factors and most likely in the range of 150 to 300 lb/10^{12} Btu. Golder Associates concludes that for the purposes of conservatively estimating formaldehyde emissions, an emission factor of 340 lb/10^{12} Btu are appropriate for the Martin Peaking Units. This is 10 times higher than originally estimated for the project. The total formaldehyde emissions an estimated to be 1.02 tons/year/turbine or 2 tons per year for the project (based on 3,390 hour/year, ISO turbine inlet and 1,776 mmBtu/hr – HHV).

Golder Associates appreciates this opportunity to provide this information to the Department. Please call me if there are any questions.

Sincerely,

Robert C. McCann Jr. for

Kennard F. Kosky, P.E.
Principal

KFK/pac

cc: Rich Piper, FPL

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cc: File
SED
EPA
NPS
B. Oven, PPS

FPL ENVIRONMENTAL SERVICES DEPARTMENT
PO BOX 14000
JUNO BEACH, FL 33408

DATE: June 2, 2000

SEND TO:
NAME: Jeff Koerner
COMPANY: DEP
FAX NUMBER: 850 922 6979

RECEIVED
JUN 02 2000
BUREAU OF AIR REGULATION

FROM: RICHARD PIPER
FPL ENVIRONMENTAL SERVICES
PHONE: (561) 691-7058
FAX: (561) 691-7070
rich_piper@fpl.com

NUMBER OF PAGES INCLUDING FAX COVER: 4

MESSAGE: Jeff -

Attached is a letter to FPLE from GE regarding formaldehyde emissions from 7FA combustion turbines. Golder will also send you a letter within a day or two. Have a great weekend!

-Rich

BEST AVAILABLE COPY

GE Power Generation

DOC. GE_Formaldehyde_Emissions

Power Systems Department
1 River Road
Schenectady, NY 12345
Building 2, Room 506
(518) 385-4698) (Tel)
(518) 385-3725 (Fax)

May 30, 2000

Mr. Robert Burgess

FPL Energy
Power Generation – New Plant Design Group
700 Universe Blvd – PO Box 14000
Juno Beach, FL 33408-0420

– FPL Martin

Subject: Formaldehyde Emissions

Dear Bob:

Unfortunately, at this time, GE cannot provide guarantees for formaldehyde emission rates because presently there are insufficient data to provide a guaranteed value. This is true since the quality of past data (those used to develop the emission factors) is often poor. For instance, early formaldehyde testing was prone to contamination, especially if measured per EPA Method SW-846 0011. Background contamination in a specific sample train is often present. In some cases, the background levels were greater than the field-test gross results. Most test companies have adopted CARB Method 430 which is less prone to contamination (but is not isokinetic).

Since no GE controlled field data is available, current practice for estimating formaldehyde emissions from gas turbines has often been to refer to U.S. EPA database AP-42. The AP-42 database contains emission factors for many hazardous air pollutants. EPA has concluded that only formaldehyde is of concern for combustion turbines. The database includes an emission factor for formaldehyde on a pound per MMBtu of fuel consumed basis. The factors are based on a survey of the available published emissions data from gas turbines of various models and manufacturers.

Our review of the EPA published database indicates that the data does not represent the state of the art turbine combustion performance. All units tested in the database have either water or steam injection for NOx control and are not representative of today's dry low NOx (DLN) combustion systems. Today's DLN systems are different because they have premixed air and fuel prior to ignition at higher combustion temperatures. By premixing, there is a better uniformity of combustion conditions which minimizes the potential for quenches that can lead to aldehyde emissions. The potential for quenching is enhanced by alternative NOx control technologies such as steam and water injection. Compared to diluent injected units, DLN has displayed exemplary emissions performance including CO levels below those achievable with the predecessor generation with water or steam injection for NOx control.

GE data indicates that CO and UHC correlate well and as CO decreases so do UHCs . Based on field data to date on the 7241FA with the 2.6 combustion system, the formaldehyde levels are expected to be lower than those reported in the EPA database.

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GE has reviewed the database and commented that the emissions factor for formaldehyde of 2.4E-3 lb/MMBtu (3.4 lb/10^6 scf) assigned initially in AP-42 was artificially high. This was due to outliers-- data points that were two orders of magnitude above the mean of the remaining data. Removing these points resulted in an average emission factor of approximately 7.1E-4 lb/MMBtu, which is currently EPA's published AP-42 value for combustion turbines firing natural gas.

The American Petroleum Institute (API) published an emission factor of 3.1×10^{-4} lb/MMBtu for gas-fired turbines (*Air Toxics Emission Factors for Combustion Sources Using Petroleum-Based Fuels*, Publication Number 348, API, August 1998). This emission factor is rated below average (may be derived from only one or two tests or downgraded because of observed deficiency in methodology).

In general, the formaldehyde measurements taken in the field are below field blanks. The use of CARB 430 has generally been the agreed upon measurement method. A measure of field blank levels is required as part of the measurement method which is often a significant fraction of the measured value due to high ambient background levels and/or contamination of absorbents. If background levels are greater than 20% of the stack level, a multiple of 5X of the background level is used instead of the measured data point for the source test.

The best detection limit for formaldehyde by CARB Method 430 (using standard sampling and analytical values) is 4-5 ppbv (5 µg/dscm). As published, CARB Method 430 requires a reporting limit equal to five times the detection limit (20-25 ppbv, 25 µg/dscm) if the gross test result is close to the detection limit. This is based on laboratory DL of 0.5 µg/sample and a 20-liter test volume.

We cannot comment on the development of this methodology except to say it appears the repeatability of the results using CARB 430 is very sensitive to background levels and/or contamination of the absorbent. This repeatability issue is one GE hopes to examine at tests planned to measure formaldehyde in the field on two GE 7241 FA turbines firing natural gas. The design of the test calls for two CARB 430 tests to be performed simultaneously on two stacks of units operating concurrently on the identical fuel supply. The design of this experiment is to eliminate fuel and ambient effects while statistically looking at test to test variations.

Results of these tests will likely not be available for three months or more. We would hope that until accurate methods and data are available to properly develop Maximum Achievable Control Technologies (MACT) standards, that EPA would hold off on publishing standards which may require unwarranted and costly controls.

We trust that the preceding provides technical information which will enable you to reach appropriate design decisions regarding your new generation development projects. If you have any questions, please don't hesitate to contact me at 518-385-4698.

Regards,

Joel Chalfin
Environmental Engineering
Global Power Plant Systems Department

Stephen J. Anchukaitis
Commercial Manager
GE Power Systems

cc: A. Linero
M. Halpin
T. Heron

FYI only.

INTEROFFICE MEMORANDUM

Date: 31-May-2000 05:13pm
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

To: Jeff.Koerner (Jeff.Koerner@dep.state.fl.us)

Subject: Annual Gas Usage

Jeff,

Pursuant to your request this morning, FPL proposes an annual limit of 5,902.59 x 10^6 scf / year per CT at Martin for the peaking units. This value is based upon the following:

Hourly heat input rate of 1776 mmBtu / hour (HHV @ 59 degrees F)

3390 hours per year x 1776 mmBtu / hour = 6,020,640 mmBtu / year

(6,020,640 mmBtu / year) / 1020 btu / scf = 5,902.59 x 10^6 btu / year

Please let me know if you have any questions.

Regards....

- Rich

INTEROFFICE MEMORANDUM

Date: 31-May-2000 01:11pm
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

To: Jeff.Koerner (Jeff.Koerner@dep.state.fl.us)

Subject: FP&L Martin - Peak Firing---100.1120

Jeff,

The note below from GE should address the control question re: peaking operation.

- Rich
---------------------- Forwarded by Rich Piper on 05/31/2000 12:16 PM ---------------------------

John Gnecco
05/24/2000 10:51 AM

To: Rich Piper@FPL, ken_kosky@golder.com
cc: Bob Burgess@FPL, Bob Lippman@FPL, Michael B Rojas@FPL, dalleryrl@bv.com, PMR Peakers@FPL

Subject: FP&L Martin - Peak Firing---100.1120

Ken,

The attached email is from GE in response to the FDEP preliminary response to item 7.

Please let me know if we need anymore information.

Thanks,
John
---------------------- Forwarded by John Gnecco on 05/24/2000 10:49 AM ---------------------------

edward.nejman@ps.ge.com on 05/24/2000 10:07:06 AM

To: John_Gnecco@fpl.com
cc: robert.clayton@ps.ge.com, marc.lindenmuth@ps.ge.com, robert.dsouza@ps.ge.com

Subject: FP&L Martin - Peak Firing

John, the following is in response to your request for information on the control system for peak Operation.

During peak load operation, the control system modulates fuel stroke reference to control exhaust temperature to the peak load reference exhaust temperature curve. This is identical to the base load exhaust temperature control functionality.

The actual turbine exhaust temperature along with compressor discharge pressure and temperature are used to generate the combustion reference temperature. The combustion reference temperature is used in the DLN control mode for switching the fuel split scheduling. During the transfer from base to peak load, the combustion system will remain in pre-mix steady state mode and the combustion reference temperature will increase due to the
higher load. The combustion reference temperature will remain in pre-mix steady state mode and the combustion reference temperature will increase due
to the higher load. The combustion reference temperature will adjust the fuel split as required to account for peak load operation.

Please let us know if this answers your question satisfactorily

Ed.

INTEROFFICE MEMORANDUM

Date: 31-May-2000 11:04am
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

To: Jeff.Koerner (Jeff.Koerner@dep.state.fl.us)

Subject: GE Data Sheets - Peaking

Jeff,

Attached are the GE data sheets for peaking operation for both gas and distillate. For some reason, one is in Excel and the other is in Word. Please let me know if you have any questions.

...and thanks for your time and assistance in reviewing the draft permit this morning.

Regards....

- Rich

(See attached file: Dist_HHV35.xls)(See attached file: FPL MARTIN PLANT Peak gas 35 dry.doc)

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%
Ambient Temp.	Deg F.	35	35	35	35
Fuel Type		Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387
Fuel LHV	Btu/lb	19,490	19,490	19,490	19,490
Fuel Temperature	Deg F	60	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78	1.78
Output	kW	190,500.00	142,900.00	95,200.00	47,600.00
Heat Rate (LHV)	Btu/kWh	9,945.00	10,550.00	12,500.00	16,660.00
Heat Cons. (LHV) X 106	Btu/h	1,894.50	1,507.60	1,190.00	793
Heat Rate (HHV)	Btu/kWh	10,541.70	11,183.00	13,250.00	17,659.60
Heat Cons. (HHV) X 106	Btu/h	2,008.17	1,598.08	1,261.40	840.58
Auxiliary Power	kW	1,390.00	1,390.00	1,390.00	1,390.00
Output Net	kW	189,110.00	141,510.00	93,810.00	46,210.00
Heat Rate (LHV) Net	Btu/kWh	10,020	10,650	12,690	17,160
Heat Rate (HHV) Net	Btu/kWh	10,619	11,293	13,446	18,190
Exhaust Flow X 103	lb/h	3,862.00	3,024.00	2,487.00	2,290.00
Exhaust Temp.	Deg F.	1,074.00	1,121.00	1,168.00	982.00
Exhaust Heat (LHV) X 106	Btu/h	1,042.60	868.70	752.40	568.40
Exhaust Heat (HHV) X 106	Btu/h	1,105.16	920.82	797.54	602.50
Water Flow	lb/h	130,930.00	94,620.00	66,770.00	29,780.00

EMISSIONS

NOx	ppmvd @ 15% O2	42.00	42.00	42.00	42.00
NOx AS NO2	lb/h	334	263	208	135
CO	ppmvd	20	24	35	269
CO	lb/h	68	65	77	566
UHC	ppmvw	7	7	7	25
UHC	lb/h	15	12	10	32
VOC	ppmvw	3.5	3.5	3.5	12.5
VOC	lb/h.	7.5	6	5	16
SO2	ppmvw	11	12	11	8
SO2	lb/h	98	78	61	41
SO3	ppmvw	1	<1.0	1	1
SO3	lb/h	6	5	5	3
Sulfur Mist	lb/h	10	8	6	4
Particulates	lb/h	17	17	17	17

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.87	0.8
Nitrogen	71.79	72.1	72.73	74.9
Oxygen	11.19	11.22	11.76	14.5
Carbon Dioxide	5.56	5.6	5.35	3.8
Water	10.6	10.23	9.29	5.7

SITE CONDITIONS

Elevation	ft.	45
Site Pressure	psia	14.68
Inlet Loss	in Water	3
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application	7FH2 Hydrogen-Cooled Generator	
Combustion System	9/42 DLN Combustor	

Emission information based on GE recommended measurement methods.
NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1).
NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.HHV adjustment factor assumed is 6%
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

Post-it® Fax Note 7671 | Date 5/31 | # of pages ▶ 1
To JEFF KOERNER | From RICH PIPER
Co./Dept FDEP | Co.
Phone # | Phone # 561 691 7058
Fax # 850 922 6979 | Fax # 7070

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	35.
Output	kW	190,300.
Heat Rate (LHV)	Btu/kWh	9,080.
Heat Cons. (LHV) X 10^6	Btu/h	1,727.9
Auxiliary Power	kW	560
Output Net	kW	189,740.
Heat Rate (LHV) Net	Btu/kWh	9,110.
Exhaust Flow X 10^3	lb/h	3713.
Exhaust Temp.	Deg F.	1109.
Exhaust Heat (LHV) X 10^6	Btu/h	1015.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	105.
CO	ppmvd	9.
CO	lb/h	30.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	75.00
Oxygen	12.39
Carbon Dioxide	3.98
Water	7.74

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973	version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO	01/28/2000 19:49 FPL MARTIN PLANT Peak gas 95 dry.dat

Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 24, 2000

CERTIFIED MAIL – Return Receipt Requested

Rich Piper
Repowering Licensing Manager
Florida Power & Light Company
P.O. Box 14000
Juno Beach, FL 33408

Re: FPL Martin Plant
PSD Permit No. PSD-FL-286

Dear Mr. Piper:

I have reviewed your comments on the Draft Permit delivered to me on May 16, 2000. As we discussed earlier, some of the requested changes related to modified stack dimensions, permitted capacity and the additional peak firing method of operation could require the publishing of a new or revised Public Notice. Before the Department can agree to the requested changes, the following additional supporting information is requested.

1. FPL states that the stack dimensions have been revised from 22 feet in diameter and 60 feet tall to 18 feet in diameter and 80 feet tall. FPL believes that the higher stack and smaller diameter should result in decreased ground level impacts.

   Response: For each fuel and method of operation, provide updated pages of the application indicating stack height, stack diameter, exhaust temperature, percent water vapor, volumetric flow rates in acfm and dscfm, and exit velocities. Please evaluate the new scenario, demonstrate that the revised project will have no significant ambient impacts, and coordinate this effort with the Department's project meteorologist, Cleve Holladay.

2. FPL requests the following changes to the permitted capacity: a maximum net power output of 190 MW for natural gas firing; a heat input rate of 2008 mmBtu/hour for distillate oil firing; and a maximum heat input of 1918 mmBTU per hour with a corresponding net power output of 182 MW for operation with power augmentation or peaking.

   Response: The manufacturer's data does not indicate a net output of 190 MW for normal gas firing. The Department has information from General Electric on the Model 7241(FA) that indicates a lower heat input rate for oil firing. Data submitted for steam augmentation and peak firing indicates 180 MW and 179 MW, respectively. Please provide data from General Electric that supports each request. A revised "Estimated Performance" data sheet from General Electric for the Model PG7241(FA) would be sufficient. Data must include the LHV and HHV (BTU/lb_m) of oil, the heat input rates based on the HHV and LHV of oil (mmBTU per hour), fuel mass flow rates (lb per hour), an inlet temperature of 35° F at 20% RH, net output in MW, exhaust mass flow rate (lb/hr), emissions characteristics, and be specific for each fuel type and method of operation.

3. FPL requests the addition of "peak firing" as an authorized method of operation limited to 60 hours per year with a corresponding reduction in power augmentation to offset any increase in emissions. FPL requests NOx limits of 15.0 ppmvd and 105 lb/hour based on a 3-hour average for peak firing mode.

   Response: FPL has described "peak firing" as a non-standard method of operation for the Model PG7241(FA), which requires specialized programming of the automated gas turbine control system by General Electric. The Department will consider 60 hours per year of "peaking" due to the very limited request. Please provide a general description of the changes to the automated gas turbine control system, the adjusted temperatures, and the method for reestablishing normal gas-firing operation. If acceptable, the Department proposes to offset the emission increases by reducing power augmentation (steam injection) from 500 hours to 400 hours during any consecutive 12 months.

4. FPL requests that annual combined heat input for both units (gas and oil operation) based on ISO conditions be used as a surrogate for operating hours, in order to provide additional operating flexibility.

   Response: Revising the condition to limit the combined heat input of both gas turbines would require a new cost analysis for both a hot SCR system and an oxidation catalyst and may result in new BACT determinations. It may also require permitting in accordance with the an "air emissions bubble" as defined by Rule 62-212.710, F.A.C. The Department believes the Draft Permit accurately reflects the request made in the application. We would consider a request for equivalent limits on fuel consumption on a per unit basis. Please specify the natural gas and distillate oil consumption limits based on 59° F and 60% RH and include supporting information for the heat input, LHV, HHV, and fuel density. If acceptable, the Department would require the installation of gas and oil fuel flow monitors with at least monthly record keeping to demonstrate compliance with the rolling 12-month fuel consumption limits.

The Department believes that the above requested changes could be considered substantial with regard to the previously Intent to Issue Draft Permit package. For further consideration of these changes, please provide the additional supporting information requested. Other requested changes are not considered substantial and are addressed in the Attachment A provided with this letter. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official.

If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Cleve Holladay, meteorologist, at 850/921-8986.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Enclosure

cc: Mr. John M. Lindsay, FPL
Mr. Richard G. Piper, FPL
Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Attachment

Note: These responses follow the same format provided in FPL's comments.

1. The new peaking units' designations will be 8A and 8B, and not 5A and 5B, as indicated in the draft.

   Response: Designations will be revised.

2. Page 6 of 14 – Emission Unit Description: FPL has changed the stack dimensions to 80' tall x 18' diameter. The higher stack and smaller diameter should result in decreased ground level impacts. Also, the heat input rate for distillate oil should be 2008 mmBtu/hour, and not 1965.

   Response: Additional information requested.

3. Page 7 of 14, Condition 4 - Permitted Capacity: We have suggested language clarifying the heat input limits on power augmentation or peak firing modes, and corrected the btu content of distillate oil.

   Response: Additional information requested.

4. Page 7 of 14, Condition 5 – Simple Cycle Operation: The draft language disallowing netting is not supported by the Department's or EPA's rules. FPL has no current plans to convert these units to combined cycle mode; but if that were to occur, the existing state and federal rules should apply, regarding baseline emissions and netting.

   Response: The Department proposes to revise the condition as follows.

   5. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Rules 62-210.300, 62-212.400, and 62-212.400(2)(g), F.A.C.]

5. Page 7 of 14, Condition 6 – Power Augmentation and Peak Firing Modes: The draft permit did not contain the requested peak firing operating mode. FPL requests that this mode be made a part of the PSD permit, and suggests that a combination of the two alternate operating modes be permitted; a maximum of 500 hours / year of power augmentation mode is requested, including 60 hours of peak mode operation; each hour of peak operation would decrease the power augmentation balance hours by 1.25 hours. This approach would result in no increase in the TPY emissions from this mode of operation.

   Response: Additional information requested.

6. Page 8 of 14, Condition 8 – Hours of Operation and Fuel Usage: FPL requests that annual heat input for both gas and oil operation be used as a surrogate for operating hours, in order to provide additional operating flexibility. We have proposed annual limits based on ISO conditions.

   Response: Additional information requested.

7. Page 8 of 14, Condition 10 – Automated Control System: The control system which FPL uses comes directly from GE. Some changes are requested to better describe what actually happens.

   Response: According to information provided by GE, the control system monitors the median exhaust temperature in order to calculate the combustion "reference" temperature. The combustion reference temperature is important because it establishes a set point at which the control system advances from one stage to the next in order to achieve lean premix firing. The Department recognizes that FPL will not design the automated gas control system. Additional information is requested regarding changes to the control system necessary for "peaking".

8. Page 9 of 14, Condition 12 – DLN Combustion Technology Installation: FPL requests that the term "tuning" be removed, since the term "maintenance" covers this activity. Language is requested that more accurately describes the relationship between CO and NOx formation.

   Response: The Department disagrees and will retain the term "tuning" in this condition. In general, CO and NOx emissions are inversely proportional, however, data provided by General Electric for the dry low-NOx 2.6 combustors indicates that both CO and NOx emissions are less than 9.0 ppmvd @ 15% O_2 between 50% and 100% of base load. This suggests that the relationship between CO and NOx for DLN units is not as strong as with conventional units.

9. Page 9 of 14, Condition 13(b) – Gas Firing With Power Augmentation or Peak Firing: FPL requests that peak firing capability be reinserted into the permit in order to allow for this type of operation.

   Response: Additional information requested.

10. Page 9 of 14, Condition 14(b) – Gas Firing With Power Augmentation or Peak Firing: FPL requests that NOx limits of 15.0 ppmvd and 105 lb. / hour be used on a 3-hour average for peak firing mode.

    Response: Additional information requested.

11. Page 10 of 14, Condition 14 (end) – FPL requests the word "or" be inserted to clarify that either EPA Method 7E or Method 20 is allowed for compliance.

    Response: EPA Method 7E may be used to satisfy the annual compliance test, but EPA Method 20 is required for the initial test in accordance with 40 CFR 60, Subpart GG.

12. Page 10 of 14, Condition 15 (b) – FPL requests an opacity limit of 10% for both oil and natural gas. This is consistent with recent DEP permits for 7FA technology.

    Response: General Electric now guarantees a visible emissions limit for gas firing of 5% opacity.

13. Page 10 of 14, Condition 17 – FPL requests that the excess emissions language in the permit should be reflective of DEP rule 62-210.700(4). Power augmentation is not appropriate to include, and further, the inclusion of data in the 3-hour averages is inappropriate because this data is already required to be reported in a per-occurrence basis in the quarterly excess emissions report.

    Response: The Department disagrees. For the excess emissions rule to apply, the unit must operate for at least three hours during power augmentation and the average NOx emissions would have to exceed the standard. The only way the excess emissions could be allowed is if there was a malfunction during this period. The Department believes it is inappropriate to continue operation with power augmentation if there has been a malfunction. Furthermore, emissions that are prohibited must be included within the compliance averaging periods. In addition, any excess emissions must also be reported in the quarter excess emissions report. Rule 62-210.700(6), F.A.C. authorizes the Department to, "... adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Because power augmentation is not part of the normal operation of this unit, the Department believes this condition is appropriate.

14. Page 11 of 14, Condition 18(c) – FPL requests that this condition be deleted. Rule 62-210.700(1) and (5) does not impose a limit on opacity values, other than to minimize them.

    Response: Again, Rule 62-210.700(6), F.A.C. authorizes the Department to, "... adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." There are only two pollutants for which the compliance status is readily known: NOx emissions by continuous monitor and visible emissions by certified observer. The compliance statuses for other pollutants are determined by conducting emissions performance tests or keeping appropriate fuel records. Generally, stack tests are not valid for periods of startup, shutdown, or malfunction, so the compliance status is unknown and the excess emissions rule would not apply. For this reason, the Department has specified an appropriate level of excess visible emissions due to startup and shutdown as a part of this permit. The Department believes that a modern gas turbine with visible emissions of 20% or greater suggests operational or equipment problems. For other incidents when a unit exceeds the visible emissions standard due to startup, shutdown, or malfunction, a compliance review would be made on a case-by-case basis by the Compliance Authorities. Attached for your information is a recent memorandum outlining EPA's concerns regarding "automatic exemptions".

15. Page 11 of 14, Condition 21 – Initial Tests Required: FPL requests that language be inserted to clarify the corrections to test data required by NSPS as opposed to those required by BACT limits.

    Response: The Department proposes the following revision:

    21. Initial Tests Required: Initial performance tests to demonstrate compliance with each emission standard for normal gas firing, gas firing with power augmentation, gas firing with peaking (if permitted), and backup distillate oil firing shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 *days after initial operation of each emissions unit. Initial performance tests shall be conducted for CO, NOx, VOC and visible emissions. Tests for CO, NOx, and VOC shall be conducted concurrently. NOx performance tests shall be conducted in accordance with the requirements of 40 CFR 60, ~~NSPS~~ Subpart GG. ~~and~~ For the initial performance tests, emissions data shall be presented in units of the BACT standards as well as the ~~also converted into~~ units specified in ~~of~~ the ~~NSPS~~ Subpart GG emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]*

16. Page 12 of 14, Condition 22 – Annual Performance Tests: FPL requests that a trigger level of 200 hours of distillate oil operation per year is appropriate and consistent with the Department's rules (reference 62-297-310.(7)(a) 8) which uses a 400 hour threshold for visible emission testing. And, the CEM will be operating during oil operation which will provide the Department quality-assured data for any oil operating hours.

    Response: The Department reviewed the quantity of emissions generated by the alternate methods of operation and proposes the following revisions to (a) and (b) of Specific Condition No. 22:

    (a) For each combustion turbine that fires distillate oil for less than 200 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required.

    (b) For each combustion turbine that operates with power augmentation for less than 200 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.

    Note: The Department will consider similar language for peak firing after review of the additional information.

17. Page 12 of 14, Condition 24 – Tests After Substantial Modification: FPL requests this condition be deleted. "Substantial modification" is not defined in DEP's rules; however "modification" is, and specifically exempts routine replacement of component parts such as dry low NOx combustors.

    Response: The Department disagrees. Replacing a major piece of equipment as well as a critical component of the pollution control system requires verification that the modified or repaired unit is in compliance with the emissions standards specified in the permit. This condition is standard language for all recent combustion turbine projects.

18. Page 13 of 14, Condition 25(c) – FPL requests this condition be deleted. Condition 25(b) has been thoroughly reviewed by the utility industry and painstakingly negotiated. No basis exists in the Department's rule to require this condition.

    Response: The Department disagrees. The applicant has specifically requested an alternate operating method with the purpose of providing a boost in power production beyond the standard capabilities of the combustion turbine for the given ambient conditions. The Department's language seeks to ensure that the emissions performance testing is conducted during conditions similar to actual operation when utilizing these methods. The Department is willing to consider alternative language from FPL that would that satisfies this requirement.

19. Condition 26 – NOx CEMs: The language is suggested in order to make the Martin permit consistent with those issued by the Department for Fort Myers and Sanford.

    Response: It is the permittee's responsibility to ensure compliance with all federal monitoring requirements. The Department has no authority to waive or substitute such requirements. The word "and" will be retained.

20. Condition 26(c) – Data Reporting: The term "block average" is not defined, and it presents a number of problems. FPL requests that the word "block" be removed in order to provide some clarity.

    Response: The Department is considering this revision.

21. Condition 26(e) – Power Augmentation Mode: There is no basis in the Department's rules to require the cessation of operation in power augmentation should a CEM fail during this mode. The acid rain rules require a high level of CEM availability anyway (>95%), so this condition is superfluous.

    Response: The Department disagrees. The permit includes allowances for limited alternate operating methods that may result in emission levels higher than the BACT standard determined for normal operation. Restricting alternate methods of operation to only those periods when the CEMS is operating properly provides the reasonable assurance necessary to approve these methods. As you indicated in your comments, the CEMS availability will be greater than

95% so there is little likelihood that this condition will create any real problems. However, it would prevent a situation in which the CEMS only malfunctions during power augmentation (or perhaps peak firing).

22. Condition 28(c) – Alternate Monitoring Plan: FPL requests the addition of one phrase which clarifies that Specific Condition 27 will be satisfied by the alternate monitoring plan.

    Response: The "Alternate Monitoring Plan" listed in Specific Condition No. 28 would satisfy the monitoring requirements of 40 CFR 60, Subpart GG not Specific Condition No. 27.

23. Condition 29 – Monthly Operation Summary: This would be a new requirement for any of FPL's facilities. The facility is already subject to a quarterly excess emissions report which could be adapted to include this information.

    Response: This condition only requires the recording of the hours of operation and fuel consumption for each unit. The information must be recorded to in order to demonstrate compliance with the limits on hours of operation, fuel usage, and permitted capacity. The condition is separate from any NSPS or Acid Rain requirement.

24. Section III, Emissions Performance Standards: The Department has restricted the opacity of emissions from the fuel gas heaters to 5%. A 10% limit is requested.

    Response: The Department believes that well maintained and operated gas-fired fuel heaters would have no visible emissions. The condition merely requires investigation and corrective actions if visible emissions are present.

Z 341 355 296

US Postal Service

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PS Form **3800**, April 1995

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PS Form 3811, July 1999

5-99-M-1789

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

September 20, 1999

MEMORANDUM

SUBJECT: State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown

FROM: Steven A. Herman
Assistant Administrator for Enforcement and Compliance Assurance

Robert Perciasepe
Assistant Administrator for Air and Radiation

TO: Regional Administrators, Regions I - X

EPA's policy for state implementation plans (SIPs) regarding excess emissions during malfunctions, startup, shutdown, and maintenance is contained in memoranda from Kathleen Bennett, formerly Assistant Administrator for Air, Noise and Radiation dated September 28, 1982 and February 15, 1983. A recent review of SIPs suggests that several contain provisions that appear to be inconsistent with this policy, either because they were inadvertently approved after EPA issued the 1982-1983 guidance or because they were part of the SIP at that time and have never been removed. In order to address these provisions in a consistent manner, today we are reaffirming and supplementing the 1982-83 policy. In so doing, we are taking this opportunity to clarify several issues of interpretation that have arisen since that time. The updated policy will clarify the types of excess emissions provisions states may incorporate into SIPs so that they can in turn provide greater certainty to the regulated community.

As EPA stated in its 1982 memorandum, because excess emissions might aggravate air quality so as to prevent attainment or interfere with maintenance of the ambient air quality standards, EPA views all excess emissions as violations of the applicable emission limitation. Nevertheless, EPA recognizes that imposition of a penalty for sudden and unavoidable malfunctions caused by circumstances entirely beyond the control of the owner or operator may not be appropriate. Accordingly, a state or EPA can exercise its "enforcement discretion" to refrain from taking an enforcement action in these circumstances.

The main question of interpretation that has arisen regarding the old policy is whether a state may go beyond this "enforcement discretion" approach and include in its SIP a provision that would, in the context of an enforcement action for excess emissions, excuse a source from penalties if the source can demonstrate that it meets certain objective criteria (an "affirmative defense"). This policy clarifies that states have the discretion to provide such a defense to actions for penalties brought for excess emissions that arise during certain malfunction, startup, and shutdown episodes.

In the context of malfunctions, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail. At the same time, EPA has a fundamental responsibility under the Clean Air Act to ensure that SIPs provide for attainment and maintenance of the national ambient air quality standards ("NAAQS")and protection of PSD increments. Thus, EPA cannot approve an affirmative defense provision that would undermine the fundamental requirement of attainment and maintenance of the NAAQS, or any other requirement of the Clean Air Act. See sections 110(a) and (l) of the Clean Air Act, 42 U.S.C. § 7410(a) and (l).[1] Accordingly, an acceptable affirmative defense provision may only apply to actions for penalties, but not to actions for injunctive relief. This restriction insures that both state and federal authorities remain able to protect air quality standards and PSD increments.

Furthermore, this approach is appropriate only when the respective contributions of individual sources to pollutant concentrations in ambient air are such that no single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments.[2] Where a single source or small

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[1]Pursuant to Section 110(l), EPA may not approve a SIP revision if "the revision would interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of this chapter." See also CAA § 193, 42 U.S.C. § 7515, and the definitions of "emission limitation" and "emission standard" contained in CAA § 302(k), 42 U.S.C. § 7602(k).

[2] In the case of lead and sulfur dioxide, attainment problems usually are caused by one or a few sources and an affirmative defense is not appropriate. This situation can be

group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, EPA believes an affirmative defense approach will not be adequate to protect public health and the environment, and the only appropriate means of dealing with excess emissions during malfunction, startup, and shutdown episodes is through an enforcement discretion approach.[3]

EPA is also taking this opportunity to clarify that it does not intend to approve SIP revisions that would allow a state director's decision to bar EPA's or citizens' ability to enforce applicable requirements. Such an approach would be inconsistent with the regulatory scheme established in Title I of the Clean Air Act. EPA is also adding contemporaneous record keeping and notification criteria to make its policy regarding these types of events consistent with its enforcement approach.

Finally, EPA is clarifying how excess emissions that occur during periods of startup and shutdown should be addressed. In general, because excess emissions that occur during these periods are reasonably foreseeable, they should not be excused. However, EPA recognizes that, for some source categories, even the best available emissions control systems might not be consistently effective during startup or shutdown periods. In areas where the respective contributions of individual sources to pollutant concentrations in ambient air are such that no single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, these technological limitations may be addressed in the underlying standards themselves through narrowly-tailored SIP revisions that take into account the potential impacts on ambient air quality caused by the inclusion of these allowances. In these instances, as part of its justification of the SIP revision, the state should analyze the

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particularly aggravated where a short-term standard (e.g., where exceedances or violations are based on a few hour period) is also in place. Although this policy is generally applicable for other NAAQS, enforcement discretion is the only appropriate approach for dealing with excess emissions during startup, shutdown, and malfunction in a specific area where a single source or a small group of sources has the potential to cause nonattainment of a short-term NAAQS.

[3] In American Trucking Association v. EPA, 175 F. 3d 1027 (D.C. Circ., 1999), the court remanded the PM2.5 NAAQS to the EPA. The Agency has not determined whether this policy is appropriate for PM2.5 NAAQS.

impact of the potential worst-case emissions that could occur during startup and shutdown.[4]

In addition to this approach, states may address this problem through the use of enforcement discretion or they may include a general affirmative defense provision in their SIPs for short and infrequent startup and shutdown periods along the lines outlined in the attachment. As mentioned above, however, in those areas where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, issues relating to excess emissions arising during startup and shutdown may only be addressed through an enforcement discretion approach.

All Regions should review the SIPs for their states in light of this clarification and take steps to insure that excess emissions provisions in these SIPs are consistent with the attached guidance.

Attachment

[4]States may account for such emissions by including them in their routine rule effectiveness estimates. Rule effectiveness estimates may be prepared in accordance with an EPA policy document entitled "Guidelines for Estimating and Applying Rule Effectiveness for Ozone/Carbon Monoxide State Implementation Plan Base Year Inventories." (EPA-452/R-92-010) November 1992.

Attachment

POLICY ON EXCESS EMISSIONS DURING MALFUNCTIONS, STARTUP, AND SHUTDOWN

Introduction

This policy specifies when and in what manner state implementation plans (SIPs) may provide for defenses to violations caused by periods of excess emissions due to malfunctions,[1] startup, or shutdown. Generally, since SIPs must provide for attainment and maintenance of the national ambient air quality standards and the achievement of PSD increments, all periods of excess emissions must be considered violations. Accordingly, any provision that allows for an automatic exemption[2] for excess emissions is prohibited.

However, the imposition of a penalty for excess emissions during malfunctions caused by circumstances entirely beyond the control of the owner or operator may not be appropriate. States may, therefore, as an exercise of their inherent enforcement discretion, choose not to penalize a source that has produced excess emissions under such circumstances.

This policy provides an alternative approach to enforcement discretion for areas and pollutants where the respective contributions of individual sources to pollutant concentrations in ambient air are such that no single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, as is often the case for sulfur dioxide and lead,[3] EPA believes approaches other than enforcement discretion are not appropriate. In such cases, any excess emissions may have a significant chance of causing an exceedance or violation of the applicable standard or PSD increment.

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[1]The term <u>excess emission</u> means an air emission level which exceeds any applicable emission limitation. <u>Malfunction</u> means a sudden and unavoidable breakdown of process or control equipment.

[2]The term <u>automatic exemption</u> means a generally applicable provision in a SIP that would provide that if certain conditions existed during a period of excess emissions, then those exceedances would not be considered violations.

[3]This policy also does not apply for purposes of PM2.5 NAAQS. In American Trucking Association v. EPA, 175 F. 3d 1027 (D.C. Circ., 1999), the court remanded the PM2.5 NAAQS to the EPA. The Agency has not determined whether this policy is appropriate for PM2.5 NAAQS.

Except where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, states may include in their SIPs affirmative defenses[4] for excess emissions, as long as the SIP establishes limitations consistent with those set out below. If approved into a SIP, an affirmative defense would be available to sources in an enforcement action seeking penalties brought by the state, EPA, or citizens. However, a determination by the state not to take an enforcement action would not bar EPA or citizen action.[5]

In addition, in certain limited circumstances, it may be appropriate for the state to build into a source-specific or source-category-specific emission standard a provision stating that the otherwise applicable emission limitations do not apply during narrowly defined startup and shutdown periods.

I. AUTOMATIC EXEMPTIONS AND ENFORCEMENT DISCRETION

If a SIP contains a provision addressing excess emissions, it cannot be the type that provides for automatic exemptions. Automatic exemptions might aggravate ambient air quality by excusing excess emissions that cause or contribute to a violation of an ambient air quality standard. Additional grounds for disapproving a SIP that includes the automatic exemption approach are discussed in more detail at 42 Fed. Reg. 58171 (November 8, 1977) and 42 Fed. Reg. 21372 (April 27, 1977). As a result, EPA will not approve any SIP revisions that provide automatic exemptions for periods of excess emissions.

The best assurance that excess emissions will not interfere with NAAQS attainment, maintenance, or increments is to address excess emissions through enforcement discretion. This policy provides alternative means for addressing excess emissions of criteria pollutants. However, this policy does not apply where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Moreover,

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[4]The term <u>affirmative defense</u> means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

[5]Because all periods of excess emissions are violations and because affirmative defense provisions may not apply in actions for injunctive relief, under no circumstances would EPA consider periods of excess emissions, even if covered by an affirmative defense, to be "federally permitted releases" under EPCRA or CERCLA.

nothing in this guidance should be construed as requiring states to include affirmative defense provisions in their SIPs.

II. AFFIRMATIVE DEFENSES FOR MALFUNCTIONS

EPA can approve a SIP revision that creates an affirmative defense to claims for penalties in enforcement actions regarding excess emissions caused by malfunctions as long as the defense does not apply to SIP provisions that derive from federally promulgated performance standards or emission limits, such as new source performance standards (NSPS) and national emissions standards for hazardous air pollutants (NESHAPS).[6] In addition, affirmative defenses are not appropriate for areas and pollutants where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Furthermore, affirmative defenses to claims for injunctive relief are not allowed. To be approved, an affirmative defense provision must provide that the defendant has the burden of proof of demonstrating that:

1. The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator;

2. The excess emissions (a) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices;

3. To the maximum extent practicable the air pollution control equipment or processes were maintained and operated in a manner consistent with good practice for minimizing emissions;

4. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, to the extent practicable, to ensure that such repairs were made as expeditiously as practicable;

5. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

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[6]To the extent a state includes NSPS or NESHAPS in its SIP, the standards should not deviate from those that were federally promulgated. Because EPA set these standards taking into account technological limitations, additional exemptions would be inappropriate.

6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;

9. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

10. The owner or operator properly and promptly notified the appropriate regulatory authority.

EPA interprets these criteria narrowly. Only those malfunctions that are sudden, unavoidable, and unpredictable in nature qualify for the defense. For example, a single instance of a burst pipe that meets the above criteria may qualify under an affirmative defense. The defense would not be available, however, if the facility had a history of similar failures because of improper design, improper maintenance, or poor operating practices. Furthermore, a source must have taken all available measures to compensate for and resolve the malfunction. If a facility has a baghouse fire that leads to excess emissions, the affirmative defense would be appropriate only for the period of time necessary to modify or curtail operations to come into compliance. The fire should not be used to excuse excess emissions generated during an extended period of time while the operator orders and installs new bags, and relevant SIP language must limit applicability of the affirmative defense accordingly.

III. EXCESS EMISSIONS DURING STARTUP AND SHUTDOWN

In general, startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

A. SOURCE CATEGORY SPECIFIC RULES FOR STARTUP AND SHUTDOWN

For some source categories, given the types of control technologies available, there may exist short periods of emissions during startup and shutdown when, despite best efforts regarding planning, design, and operating procedures, the otherwise applicable emission limitation cannot be met. Accordingly, except in the case where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, it may be appropriate, in consultation with EPA, to create narrowly-tailored SIP revisions that take these technological limitations into account and state that the otherwise applicable emissions limitations do not apply during narrowly defined startup and shutdown periods. To be approved, these revisions should meet the following requirements:

1. The revision must be limited to specific, narrowly-defined source categories using specific control strategies (e.g., cogeneration facilities burning natural gas and using selective catalytic reduction);

2. Use of the control strategy for this source category must be technically infeasible during startup or shutdown periods;

3. The frequency and duration of operation in startup or shutdown mode must be minimized to the maximum extent practicable;

4. As part of its justification of the SIP revision, the state should analyze the potential worst-case emissions that could occur during startup and shutdown;

5. All possible steps must be taken to minimize the impact of emissions during startup and shutdown on ambient air quality;

6. At all times, the facility must be operated in a manner consistent with good practice for minimizing emissions, and the source must have used best efforts regarding planning, design, and operating procedures to meet the otherwise applicable emission limitation; and

7. The owner or operator's actions during startup and shutdown periods must be documented by properly signed, contemporaneous operating logs, or other relevant evidence.

B. GENERAL AFFIRMATIVE DEFENSE PROVISIONS RELATING TO STARTUP AND SHUTDOWN

In addition to the approach outlined in Section II(A) above, states may address the problem of excess emissions occurring during startup and shutdown periods through an enforcement discretion approach. Further, except in the case where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, states may also adopt for their SIPs an affirmative defense approach. Using this approach, all periods of excess emissions arising during startup and shutdown must be treated as violations, and the affirmative defense provision must not be available for claims for injunctive relief. Furthermore, to be approved, such a provision must provide that the defendant has the burden of proof of demonstrating that:

1. The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

2. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions;

5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable;

6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and

9. The owner or operator properly and promptly notified the appropriate regulatory authority.

If excess emissions occur during routine startup or shutdown periods due to a malfunction, then those instances should be treated as other malfunctions that are subject to the malfunction provisions of this policy. (Reference Part I above).

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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MAY 1 9 2000
BUREAU OF AIR REGULATION

4 APT-ARB

A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for FPL - Martin Power Plant (PSD-FL-286) located in Martin County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for FPL - Martin Power Plant dated April 28, 2000. The preliminary determination is for the proposed construction and operation of two simple cycle combustion turbines (CTs) with a total nominal generating capacity of 340 MW to be located near Indiantown, FL. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CTs will be allowed to fire natural gas up to 3,390 hours per year and fire No. 2 fuel oil a maximum of 500 hours per year. The CTs will be allowed to operate in power augmentation mode for a maximum of 500 hours/year. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we have the following comments:

1. We suggest you verify the emission rate used by Golder Associates to estimate potential formaldehyde emissions. The emission factor cited by Golder is only one-fifth of the emission factor cited for formaldehyde from natural gas turbines in the recently revised section 3.1 of AP-42. Additionally, the emission factor used by Golder (cited as "Golder Associates, 2000") is not included in the reference section of the application. A complete reference for this emission factor should be provided by Golder along with an explanation for why this emission factor is more appropriate than the emission factor from AP-42.

2. As indicated in the last condition of the excess emission section, the Florida Department of Environmental Protection (FDEP) is proposing "For NO_x excess emissions due to startup, shutdown or documented malfunction during any calendar day, two hourly averages of monitoring data may be excluded from continuous NO_x compliance demonstration." It is the

Environmental Protection Agency's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods. Additionally, it is unclear what is meant by "two hourly averages" and the condition should be reworded to clarify the intent (i.e., two 1-hour averages).

3. We are pleased to see that FDEP re-performed the cost analysis for the SCR and CO oxidation add-on control systems. FDEP concluded the cost effectiveness for the add-on controls were as low as $10,000/ton removed of NO_x and $6,000/ton removed of CO. The original application's cost analysis calculated the cost effectiveness of SCR as $13,636/ton removed of NO_x and $7,595/ton removed of CO and contained several items which should not have been included in the cost analysis or needed further clarification. For instance, the application included the cost for additional NO_x monitoring and instrumentation and a 3% contingency fee in the annual cost section in addition to the 3% contingency fee included in the capital cost section.

Thank you for the opportunity to comment on the FPL - Martin Power Plant preliminary determination and draft PSD permit. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Koerner, DAR
B. Oven, PPS
SED
NPS

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 19-May-2000 03:39pm
From: Jeff Koerner TAL
KOERNER_J
Dept:
Tel No:

To: Rich Piper (Rich_Piper@fpl.com)

Subject: Draft Response to FPL's Comments on Martin (Partial)

Rich,

I just got time to day to review your comments. I am not finished, but I am attaching an initial draft because some will require additional information. In particular, I talked to our staff meteorologist (Chris Carlson) about changing the stack dimensions. He indicated that it would be necesary to provide a full revision of the Air Qulaity Analysis. You may want to discuss this with Cleve Holladay first - he worked on the Martin project, but is out today. I will try to finish up my review by Monday and email you our finished response.

Jeff

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DRAFT

Rich Piper
Repowering Licensing Manager
Florida Power & Light Company
P.O. Box 14000
Juno Beach, FL 33408

Re: FPL Martin Plant
PSD Permit No. PSD-FL-286

Dear Mr. Piper:

I have reviewed your comments on the Draft Permit received on May 16, 2000 and provide the following initial responses. Some of the responses require additional supporting information. The Department is considering your request, but reserves the right to ask other questions before agreeing to any changes to the Draft Permit already issued.

1. The new peaking units' designations will be 8A and 8B, and not 5A and 5B, as indicated in the draft.

   Response: Designations will be revised.

2. Page 6 of 14 – Emission Unit Description: FPL has changed the stack dimensions to 80' tall x 18' diameter. The higher stack and smaller diameter should result in decreased ground level impacts. Also, the heat input rate for distillate oil should be 2008 mmBtu/hour, and not 1965.

   Response: For each fuel and operating mode, please provide updated pages of the application indicating stack height, stack diameter, exhaust temperature, percent water vapor, volumetric flow rates in acfm and dscfm, and exit velocities. Because it is possible for higher stacks to result in higher pollutant concentrations at greater distances from the project, please provide a fully revised Air Quality Analysis.

   None of the *manufacturer's data* indicate a heat input rate for oil firing of 2008 mmBTU per hour. The Department has information from another project for the GE Model 7241(FA) that suggests the heat input for oil firing may be physically limited due to the equipment. Please provide supporting data *from the manufacturer* for the requested heat input based on the HHV of oil as well as the LHV and HHV of the oil. A revised "Estimated Performance" data sheet from General Electric based on the HHV of oil for the Model 7241(FA) would be sufficient. Data should include the LHV and HHV (BTU/lbm), fuel mass flow rates, an inlet temperature of 35° F at 20% RH, net output in MW, exhaust flow rate (lb/hr), and emissions characteristics.

3. Page 7 of 14, Condition 4 - Permitted Capacity: We have suggested language clarifying the heat input limits on power augmentation or peak firing modes, and corrected the btu content of distillate oil.

   Response: Again, none of the manufacturer's data suggests a net output of 190 MW for normal gas firing. The data submitted for steam augmentation and peak firing indicate 180 MW and 179 MW, respectively. Again, please provide supporting information for this change as requested in No. 2.

4. Page 7 of 14, Condition 5 – Simple Cycle Operation: The draft language disallowing netting is not supported by

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the Department's or EPA's rules. FPL has no current plans to convert these units to combined cycle mode; but if that were to occur, the existing state and federal rules should apply, regarding baseline emissions and netting.

Response: The Department proposes to revise the condition as follows.

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<u>Simple Cycle Operation Only</u>: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Rule 62-212.400(2)(g), F.A.C.]

5. Page 7 of 14, Condition 6 – Power Augmentation and Peak Firing Modes: The draft permit did not contain the requested peak firing operating mode. FPL requests that this mode be made a part of the PSD permit, and suggests that a combination of the two alternate operating modes be permitted; a maximum of 500 hours / year of power augmentation mode is requested, including 60 hours of peak mode operation; each hour of peak operation would decrease the power augmentation balance hours by 1.25 hours. This approach would result in no increase in the TPY emissions from this mode of operation.

   <u>Response</u>: The Department will consider 60 hours per year of "peaking" due to the very limited request. However, the Department proposes to offset the emission increases by reducing power augmentation (steam injection) from 500 hours to 400 hours during any consecutive 12 months. According to my calculations, this would result in a minimal increase of 0.7 tons of NOx per year.

6. Page 8 of 14, Condition 8 – Hours of Operation and Fuel Usage: FPL requests that annual heat input for both gas and oil operation be used as a surrogate for operating hours, in order to provide additional operating flexibility. We have proposed annual limits based on ISO conditions.

   <u>Response</u>: The requested change, as stated, would require a new analysis of the cost effectiveness for hot SCR. The Department believes the Draft Permit accurately reflects the request made in the application.

7. Page 8 of 14, Condition 10 – Automated Control System: The control system which FPL uses comes directly from GE. Some changes are requested to better describe what actually happens.

   <u>Response</u>: According to information provided by GE, the control system monitors the median exhaust temperature in order to calculate the combustion "reference" temperature. The combustion reference temperature is important because it establishes a set point at which the control system advances from one stage to the next in order to achieve lean premix firing. The Department recognizes that FPL will not design the automated gas control system. Please provide additional information regarding the changes in the control system necessary for "peaking" as it is a non-standard GE item.

8. Page 9 of 14, Condition 12 – DLN Combustion Technology Installation: FPL requests that the term "tuning" be removed, since the term "maintenance" covers this activity. Language is requested that more accurately describes the relationship between CO and NOx formation.

   <u>Response</u>: The Department disagrees and will retain the term "tuning" in this condition. In general, CO and NOx emissions are proportional, however, data provided by General Electric for the dry low-NOx 2.6 combustors indicates that both CO and NOx emissions are less than 9.0 ppmvd @ 15% O_2 between 50% and 100% of base load.

9. Page 9 of 14, Condition 13(b) – Gas Firing With Power Augmentation or Peak Firing: FPL requests that peak firing capability be reinserted into the permit in order to allow for this type of operation.

   <u>Response</u>: Peak firing will be considered after the additional information previously requested is submitted.

10. Page 9 of 14, Condition 14(b) – Gas Firing With Power Augmentation or Peak Firing: FPL requests that NOx limits of 15.0 ppmvd and 105 lb. / hour be used on a 3-hour average for peak firing mode.

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Response: Peak firing will be considered after the additional information previously requested is submitted.

11. Page 10 of 14, Condition 14 (end) – FPL requests the word "or" be inserted to clarify that either EPA Method 7E or Method 20 is allowed for compliance.

    Response: EPA Method 7E may be used to satisfy the annual compliance test, but EPA Method 20 is required for the initial test in accordance with 40 CFR 60, Subpart GG.

12. Page 10 of 14, Condition 15 (b) – FPL requests an opacity limit of 10% for both oil and natural gas. This is consistent with recent DEP permits for 7FA technology.

    Response: General Electric now guarantees a visible emissions limit for gas firing of 5% opacity.

13. Page 10 of 14, Condition 17 – FPL requests that excess emissions excess emissions language in the permit should be reflective of DEP rule 62-210.700(4). Power augmentation is not appropriate to include, and further, the inclusion of data in the 3-hour averages is inappropriate because this data is already required to be reported in a per-occurrence basis in the quarterly excess emissions report.

    Response: The Department disagrees. For the excess emissions rule to apply, the unit would have to be operated for at least three hours during power augmentation and the average NOx emissions would have to exceed the standard. The only way the excess emissions could be allowed is if there was a malfunction during this period. The Department believes it is inappropriate to continue to operate with power augmentation if there has been a malfunction. Furthermore, emissions that are prohibited must be included within the compliance averaging periods. In addition, any excess emissions must also be reported in the quarter report. Rule 62-210.700(6), F.A.C. authorizes the Department to, "… adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Because power augmentation is not part of the normal operation of this unit, the Department believes this condition is appropriate.

14. Page 11 of 14, Condition 18(c) – FPL requests that this condition be deleted. Rule 62-210.700(1) and (5) does not impose a limit on opacity values, other than to minimize them.

    Response: Again, Rule 62-210.700(6), F.A.C. authorizes the Department to, "… adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Other applicants have accepted these requirements.

FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

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MAY 16 2000
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May 16, 2000

Mr. Jeff Koerner, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: FPL Martin Plant
PSD Permit #PSD-FL-286

Dear Mr. Koerner:

FPL offers the following comments on the draft PSD permit for the Martin peaking units, submitted to the Department on February 19, 2000. FPL has prepared a marked-up version of the permit which is attached for your reference; an electronic version is also available.

1. The new peaking units' designations will be 8A and 8B, and not 5A and 5B, as indicated in the draft.

2. Page 6 of 14 – Emission Unit Description: FPL has changed the stack dimensions to 80' tall x 18' diameter. The higher stack and smaller diameter should result in decreased ground level impacts. Also, the heat input rate for distillate oil should be 2008 mmBtu/hour, and not 1965.

3. Page 7 of 14, Condition 4 - Permitted Capacity: We have suggested language clarifying the heat input limits on power augmentation or peak firing modes, and corrected the btu content of distillate oil.

4. Page 7 of 14, Condition 5 – Simple Cycle Operation: The draft language disallowing netting is not supported by the Department's or EPA's rules. FPL has no current plans to convert these units to combined cycle mode; but if that were to occur, the existing state and federal rules should apply, regarding baseline emissions and netting.

5. Page 7 of 14, Condition 6 – Power Augmentation and Peak Firing Modes: The draft permit did not contain the requested peak firing operating mode. FPL requests that this mode be made a part of the PSD permit, and suggests that a combination of the two alternate operating modes be permitted; a maximum of 500 hours / year of power augmentation mode is requested, including 60 hours of peak mode operation; each hour of peak operation would decrease the power augmentation balance hours by 1.25 hours. This approach would result in no increase in the TPY emissions from this mode of operation.

6. Page 8 of 14, Condition 8 – Hours of Operation and Fuel Usage: FPL requests that annual heat input for both gas and oil operation be used as a surrogate for operating hours, in order to provide additional operating flexibility. We have proposed annual limits based on ISO conditions.

7. Page 8 of 14, Condition 10 – Automated Control System: The control system which FPL uses comes directly from GE. Some changes are requested to better describe what actually happens.

8. Page 9 of 14, Condition 12 – DLN Combustion Technology Installation: FPL requests that the term "tuning" be removed, since the term "maintenance" covers this activity. Language is requested that more accurately describes the relationship between CO and NOx formation.

9. Page 9 of 14, Condition 13(b) – Gas Firing With Power Augmentation or Peak Firing: FPL requests that peak firing capability be reinserted into the permit in order to allow for this type of operation.

10. Page 9 of 14, Condition 14(b) – Gas Firing With Power Augmentation or Peak Firing: FPL requests that NOx limits of 15.0 ppmvd and 105 lb. / hour be used on a 3-hour average for peak firing mode.

11. Page 10 of 14, Condition 14 (end) – FPL requests the word "or" be inserted to clarify that either EPA Method 7E or Method 20 is allowed for compliance.

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13. Page 10 of 14, Condition 17 – FPL requests that excess emissions excess emissions language in the permit should be reflective of DEP rule 62-210.700(4). Power augmentation is not appropriate to include, and further, the inclusion of data in the 3-hour averages is inappropriate because this data is already required to be reported in a per-occurrence basis in the quarterly excess emissions report.

14. Page 11 of 14, Condition 18(c) – FPL requests that this condition be deleted. Rule 62-210.700(1) and (5) does not impose a limit on opacity values, other than to minimize them.

15. Page 11 of 14, Condition 21 – Initial Tests Required: FPL requests that language be inserted to clarify the corrections to test data required by NSPS as opposed to those required by BACT limits.

16. Page 12 of 14, Condition 22 – Annual Performance Tests: FPL requests that a trigger level of 200 hours of distillate oil operation per year is appropriate and consistent with the Department's rules (reference 62-297-310.(7)(a) 8) which uses a 400 hour threshold for visible emission testing. And, the CEM will be operating during oil operation which will provide the Department quality-assured data for any oil operating hours.

17. Page 12 of 14, Condition 24 – Tests After Substantial Modification: FPL requests this condition be deleted. "Substantial modification" is not defined in DEP's rules; however "modification" is, and specifically exempts routine replacement of component parts such as dry low NOx combustors.

18. Page 13 of 14, Condition 25(c) – FPL requests this condition be deleted. Condition 25(b) has been thoroughly reviewed by the utility industry and painstakingly negotiated. No basis exists in the Department's rule to require this condition.

19. Condition 26 – NOx CEMs: The language is suggested in order to make the Martin permit consistent with those issued by the Department for Fort Myers and Sanford.

20. Condition 26(c) – Data Reporting: The term "block average" is not defined, and it presents a number of problems. FPL requests that the word "block" be removed in order to provide some clarity.

21. Condition 26(e) – Power Augmentation Mode: There is no basis in the Department's rules to require the cessation of operation in power augmentation should a CEM fail during this mode. The acid rain rules require a high level of CEM availability anyway (>95%), so this condition is superfluous.

22. Condition 28(c) – Alternate Monitoring Plan: FPL requests the addition of one phrase which clarifies that Specific Condition 27 will be satisfied by the alternate monitoring plan.

23. Condition 29 – Monthly Operation Summary: This would be a new requirement for any of FPL's facilities. The facility is already subject to a quarterly excess emissions report which could be adapted to include this information.

24. Section III, Emissions Performance Standards: The Department has restricted the opacity of emissions from the fuel gas heaters to 5%. A 10% limit is requested.

Jeff, I appreciate your excellent work on this application and draft permit and look forward to working with you to resolve these issues. I have attached a marked-up copy of the draft permit for your use. Please do not hesitate to contact me at (561) 691-7058 if I you have any questions.

Very truly yours,

Rich Piper

Rich Piper
Repowering Licensing Manager
Florida Power & Light Company

cc: B. Oven, PPS
EPA
NPS
SED

(DRAFT)

PERMITTEE:

Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911
Expires:	June 1, 2002

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality. The permit authorizes installation at the existing power plant of two simple cycle, 170 MW combustion turbines with electrical generator sets fired primarily with natural gas.

The project will be constructed at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46".

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A - Terminology
Appendix BD - Department's BACT Determinations
Appendix E - Emissions Standards Summary
Appendix GC - Construction Permit General Conditions
Appendix GG - NSPS Subpart GG Requirements for Gas Turbines
Appendix XS - CEMS Excess Emissions Report

(DRAFT)

____
Howard L. Rhodes, Director
Division of Air Resources Management

Date: ________________

FACILITY DESCRIPTION

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's and are fired with low sulfur residual oil and/or natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	Emission Unit Description
011	Simple Cycle Unit No. 8~~5~~A: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
012	Simple Cycle Unit No. 8~~5~~B: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 5A and 5B.

REGULATORY CLASSIFICATION

HAPs: Based on the Title V permit, the existing facility is a major source of hazardous air pollutants (Title III). This project is not, in and of itself, major for HAPs.

Acid Rain: The existing facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: The existing facility is a Title V major source of air pollution because potential emissions of at least one pollutant such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceed 100 tons per year.

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, each new project requires a PSD applicability review. For each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C., a determination of Best Available Control Technology (BACT) is required. For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: Emissions units are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 02/19/00 and all related correspondence.

The following conditions apply to all emissions units and activities defined for this project.

GENERAL REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, 400 North Congress Avenue, P.O. Box 15425, West Palm Beach, Florida 33416-5425. The phone number is 561/681-6600 and the fax number is 561/681-6755.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.

4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for routine operation of the permitted emissions units. The permittee shall apply for and receive a Title V operation permit prior to expiration of this permit. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Applicable Test Procedures

    (a) *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)1. and 2., F.A.C.]

(b) *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

(c) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

20. Determination of Process Variables

(a) *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

21. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS

22. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

REPORTS

23. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

24. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

This section of the permit addresses the following new emissions units.

EU ID No.	Common Emission Unit Description
011 012	Simple Cycle Units Nos. 8~~5~~A and 8~~5~~B: Each unit consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 80~~60~~ feet tall and 18~~22~~ feet in diameter, and associated support equipment. *Natural Gas*: When firing 1858 mmBTU (HHV) per hour of natural gas, each unit produces a maximum 182 MW of power at a compressor inlet air temperature of 35° F. Dry low-NOx (DLN) combustion technology will control NOx emissions. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,461,000 acfm at 1095° F. *Distillate Oil*: When firing 2,008~~1965~~ mmBTU per hour of low sulfur distillate oil as a backup fuel for up to 500 hours per year, each unit produces a maximum 189 MW of power at a compressor inlet air temperature of 35° F. Water injection will control NOx emissions. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,539,000 acfm at 1075° F. *Power Augmentation Mode*: When injecting steam during power augmentation mode for up to 500 hours per year, each unit produces a maximum 180 MW of power at a compressor inlet air temperature greater than 59° F although this activity may be performed at lower ambient conditions. Emissions of CO and NOx from the dry low-NOx combustion system will be slightly higher during the power augmentation mode. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,403,000 acfm at 1130° F.

Note: The official designation of these units are 8A and 8B. The higher stack and higher velocity resulting from the smaller stack diameter will decrease ground level impacts.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}) and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (a) *Subpart A, General Provisions*, incuding:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) *Subpart GG, Standards of Performance for Stationary Gas Turbines* are identified in *Appendix GG* of this permit. These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

PERFORMANCE RESTRICTIONS

3. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines with electrical generator sets, each designed to produce a nominal 170 MW of electrical power. [Applicant Request; Design]

4. Permitted Capacity: The heat input to each combustion turbine from normal gas firing shall not exceed 1858 mmBTU per hour based on the following: 100% base load (~~182~~190 MW); a higher heating value (HHV) of 23,127 BTU/lb$_m$ for natural gas; and compressor inlet air conditions of 35° F and 20% RH. The heat input to each combustion turbine from firing distillate oil shall not exceed 2,008~~1965~~ mmBTU per hour based on the following: 100% base load (189 MW); a higher heating value (HHV) of 19,469~~19,365~~ BTU/lb$_m$ for distillate oil; and compressor inlet air conditions 35° F and 20% RH. The heat input to each combustion turbine from gas firing while in power augmentation or peak modes shall not exceed 1,918 mmBTU per hour based on the following: 100% base load (182 MW); a higher heating value (HHV) of 23,127 BTU/lb$_m$ for natural gas; and compressor inlet air conditions of 35° F and 20% RH. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.] Note: The distillate oil firing heat input reflects the information in the application and the basis of HHV to LHV of distillate fuel oil (i.e., a ratio of 1.06). The heat capacities of power augmentation and peak modes should be included.

5. Simple Cycle Operation ~~Only~~: Each combustion turbine is intended to~~shall~~ operate only in simple cycle mode. This ~~restriction is based on the permittee's request, which~~ formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. If these units are modified to combined cycle operation, the requirements in Chapter 62-212 F.A.C. shall be followed in determining PSD applicability and requirements. ~~Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be considered a phased project and will require a new PSD permit as if the existing project had never been constructed (no netting). Note: At the time of permit issuance, selective catalytic reduction was capable of achieving a NOx emission rate of 3.5 ppmvd corrected to 15% oxygen.~~ [Rule 62-212.400(6)(b), F.A.C.; 40 CFR 51.166(j)(4)] Note: This requirement goes beyond the regulatory framework of PSD applicability and is not appropriate as a specific permit condition. If converted to combined cycle, PSD applicability will be governed by the Department's Rules in Chapter 62-212 F.A.C and the definitions in Chapter 62-210 F.A.C. As such PSD applicability must be evaluated from a facility basis, rather than from an emission unit basis. As mentioned in several correspondences, including FPL's 10-Year Site Plan, submitted annually to the Florida Public Service Commission, these units are not currently part of a phased ~~e~~construction project.

6. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by this permit. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in this permit. [Application; Rule 62-210.200(PTE), F.A.C.]

7. Power Augmentation and Peak Firing Modes: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine or the turbine operated at higher firing temperatures when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed total of 500 hours of operation ~~power augmentation~~ including a maximum of 60 hours of peak firing during any consecutive 12 months. The total amount of power augmentation/peak firing (i.e., 500 hours) is decreasesd by 1.25 hours for each hour operated in peak firing

mode. ~~To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions.~~ Prior to activating and after deactivating power augmentation/peak firing, the operator shall log the date, time, and new mode of operation. Power augmentation or peak firing when firing distillate oil is prohibited. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]Note: Peak mode is a requested mode of operation that will only be used in emergency conditions to provide additional electric power. The 60 ~~days~~hours would provide about 2.5 days of service. The decrease in hours of 1.25 hour is based on the ratio of NOx emissions for each mode (i.e., 15 ppmvd/12 ppmvd). With this condition, there is no increase in tons/year emissions from this mode of operation being added to the draft permit. The condition requiring 95% or greater of baseload should be omitted, since the GE control system will regulate the power augmentation and peak modes.

8. Hours of Operation and Fuel Usage: ~~Each~~ Both combustion turbine~~s~~ shall be limited to 12,041,280 mmBtu when firing natural gas during any consecutive 12 months which is equivalent to operating~~e~~ ~~no more than~~ both turbines for 3390 hours over ~~during any~~ ~~consecutive~~ 12 months at ISO conditions. ~~Of this total,~~ Eeach unit shall not exceed 500 hours of power augmentation/peak firing modes during any consecutive 12 months; the total amount of power augmentation/peak firing (i.e., 500 hours) is decreasesd by 1.25 hours for each hour operated in peak firing mode. ~~and~~ Both combustion turbines shall be limited to 14 million gallons of distillate oil during any consecutive 12 month period, which is equivalent of operating both turbines for 500 hours ~~of distillate oil firing during any consecutive~~ over 12 months at ISO conditions. The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each mode of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]Note: The use of a cumulative fuel limitation for both turbines, rather than hours of operation will allow flexibility to operate the turbines. ISO conditions are used as the basis since this is the basis of the annual emissions estimates. The requested fuel limit of 12,041,280 for natural gas firing is calculated based on 1,776 mmBtu/hr (HHV-ISO) times 3,390 hours per year times 2 turbines. The requested fuel limit for oil firing of 14 million gallons is calculated based on 1,919 mmBtu/hr (HHV-ISO) divided by 137.7 mmBtu (HHV)/1,000 gallon times 500 hours times 2 turbines.

9. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS CONTROLS

10. Automated Control System: In accordance with the manufacturer's recommendations, the permittee intends to ~~shall~~ install, calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system ~~shall be~~ is designed by the manufacturer ~~and operated~~ to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, ~~combustion temperatures~~, heat input, and fully automated startup, and shutdown., ~~and cool down.~~ [Design; 62-212.400(BACT), F.A.C.] Note: FPL has no control over the design of the control system. With the exception of the peak firing, the control system is General Electric's standard system. Please note that GE's system does not monitor combustion temperature but rather several temperatures in system including the first blade of the power turbine. The term "cool down" is redundant to shutdown in the context of the sentence.

11. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, ~~tune,~~ operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine . [Design; Rule 62-212.400(BACT), F.A.C.]

12. DLN Combustion Technology Installation~~Tuning~~: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be installed ~~tuned~~ to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained ~~and tuned~~ in accordance with the manufacturer's recommendations to minimize these pollutant emissions. ~~During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better.~~ [Design; Rule 62-212.400(BACT), F.A.C.] Note: The term "tuned" should be omitted since the term "maintenance" implicitly reflects that the permittee must maintain the system according to manufacturer's specifications. The last sentence is contrary to the mechanism of CO and NOx formation (i.e., they are inversely related) and redundant to the emission limitation contained in the permit. Moreover, the control systems will be optimized for NOx control, since continuous compliance is based on NOx.

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix E of this permit.}

13. Carbon Monoxide (CO)

    (a) *Gas Firing, Normal*: When firing natural gas under normal operating -conditions, CO emissions from each combustion turbine shall not exceed 32.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

    (b) *Gas Firing With Power Augmentation or Peak Firing*: When firing natural gas and injecting steam to provide power augmentation or in peak firing mode, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher.

    (c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

    The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

14. Nitrogen Oxides (NOx)

    (a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

    (b) *Gas Firing With Power Augmentation or Peak Firing*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor. When firing natural gas and in peak firing mode, NOx emissions from each combustion turbine shall not exceed 105 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to

15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor

(c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E~~,~~ or 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332] Note: The "or" clarifies the intent of the sentence to allow either EPA Method.

15. Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2)

(a) *Fuel Specifications.* Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

(b) *VE Standard.* When firing natural gas with or without power augmentation, visible emissions from each combustion turbine shall not exceed 10~~5~~% opacity, based on a 6-minute average. When firing distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]Note: A 10% opacity is appropriate for both natural gas and distillate oil firing based on previous FDEP permits (see IPS Desoto).

16. Volatile Organic Compounds (VOC)

(a) *Gas Firing With or Without Power Augmentation/Peak Firing*: When firing natural gas, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

(b) *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25 or~~,~~ 25A, and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, ~~power augmentation,~~ or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. ~~All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard.~~ [Rule 62-210.700(4), F.A.C.]Note: This language goes beyond the rule identified for the condition and that

incorporated in other permits. Moreover, and emission in excess of the limits must be reported in the quarterly report and identified as to the reason for the emission exceedance.

18. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

   (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

   (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

   (c) ~~During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.~~ [Design and Rule 62-210.700(1) and (5), F.A.C.]Note: This goes beyond the excess emission rule, which does not specify limits that may occur during excess emissions.

   (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For excess NOx emissions due startup, shutdown, and documented malfunctions during any calendar day, two hourly averages of monitoring data shall~~may~~ be excluded from the continuous NOx compliance demonstration. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]Note: The cited rules allow the exclusion of these occurrences.

EMISSIONS PERFORMANCE TESTING

19. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR 60.40a(b)]

20. Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C.

   (a) EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources

   (b) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources

   (c) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources

   (d) EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

   (e) EPA Methods 25 or 25A - Determination of Volatile Organic Concentrations *{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.}*

   No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [40 CFR 60, Appendix A; Rule 62-204.800, F.A.C.]

21. Initial Tests Required: Initial performance tests to demonstrate compliance with each emission standard for normal gas firing, gas firing with power augmentation, and backup distillate oil firing shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of each emissions unit. Initial performance tests shall be conducted for CO, NOx, VOC and visible emissions. Tests for CO, NOx, and VOC shall be conducted concurrently. NOx performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and emissions data also shall be converted into units specified in Subpart GG to demonstrate compliance with~~of~~ the NSPS emissions

standard. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]Note: This clarifies the intent of the sentence. The NSPS has an ISO correction equation that is not applicable to the BACT limits.

22. Annual Performance Tests: Annual performance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup distillate oil firing. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1[st] to September 30[th]). CO and NOx performance tests shall be conducted concurrently. If conducted at permitted capacity, NOx emissions data collected during the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test.

    (a) If ~~no~~ distillate oil was fired less than 200 hours during the previous 12~~24~~ months of operation ~~(other than for purposes of testing)~~, the annual performance tests when firing distillate oil shall not be required. Note: This request is consistent with the Department's rules (i.e., allowing a certain limited hours of operation during a year) and provides a window for having tests conducted. Moreover, the CEMS will still be operating during any operation on oil and provide the Department reasonable assurance that the emission limits are not being exceeded..

    (b) If power augmentation and peak firing were~~as not used~~ operated less than 200 hours during the previous 12~~24~~ months of operation (other than for purposes of testing), the annual performance tests for that mode of operation shall not be required. (See note above.)

    [Rule 62-297.310(7)(a)4., F.A.C.]

23. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for each combustion turbine to demonstrate compliance with the CO, NOx, VOC and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup oil firing. Tests for CO, NOx, and VOC emissions shall be conducted concurrently. All tests shall be conducted within the 12 months prior to renewing the air operation permit. [Rule 62-297.310(7)(a)3., F.A.C.]

24. ~~Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment, including the replacement of dry low NOx combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine.~~ [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]Note: This condition has no regulatory basis in Department's rules. Modifications are specifically defined in Chapter 62-210 and the term "substantial modification" has no definition. Moreover, routine maintenance is specifically allowed as an exclusion to the term modification. Inclusion of this condition will only create confusion since it cannot be interpreted by any of the Department's rules or guidance. It should be recognized that continuous compliance using CEMS is required by the permit for the main air pollutant of concern, NOx. This alone provides the Department assurance that any routine maintenance activities will meet emission standards.

25. Combustion Turbine Testing Capacity

    (a) Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines.

    (b) Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.

(c) ~~Performance tests for gas firing with the power augmentation mode shall be conducted when operating each combustion turbine at a heat input rate of 100% or greater than that predicted by the manufacturer to achieve a maximum base load rate adjusted for the compressor inlet air conditions. The steam injection rate shall be no lower than 90% of the maximum steam injection rate.~~ Note: Testing during power augmentation or peak firing modes should follow the same procedures in Specific Condition 25. (b) as during other times. The language in Specific Condition 25. (b) has been discussed, reviewed and acknowledged over the last 5 years as the appropriate for testing gas turbines. In addition, it has no basis in the Department's rules.

[Rule 62-297.310(2), F.A.C.; 40 CFR 60.335]

CONTINUOUS MONITORING REQUIREMENTS

26. NOx CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NOx monitoring devices shall comply with the certification requirements, quality assurance procedures, and all other provisions of Performance Specifications 2 and 3 as defined in Appendix B of 40 CFR 60 or~~and~~ the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of the following information: CEM equipment specifications, manufacturer, model, type, calibration and maintenance needs, and the proposed location. Note: The requirements of 40 CFR 60 and 40 CFR 75 conflict in some ways, regarding number & frequency of calibration gas checks, etc. The suggested "or" is consistent with the Fort Myers and Sanford air construction permits.

   (a) *Installation.* Each CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and Appendix F of 40 CFR 60 or 40 CFR Part 75.

   (b) *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Each valid 1-hour average shall be calculated using at least two valid data points at least 15 minutes apart.

   (c) *Data Reporting.* Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 3-hour ~~block~~ average. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 3-hour ~~block~~period -of valid hourly emission rates. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (~~1~~3) working days of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required by this permit. Note: The term "block average" is not defined, and presents a number of potential problems, such as 1) when does a block average start (i.e. is it predefined to run from 12-3, 3-6, etc., or does it begin at startup? 2) What happens during hours when the CEM data is not valid? 3) How are partial hours handled? Suggest that removing the word "block" may fix these problems.

   (d) *Data Exclusion.* Unless prohibited by 62-210.700 F.A.C., valid hourly emission rates shall not include periods of excess emissions due to start up, shutdown, or documented malfunction as described and limited under the excess emissions requirements of this permit. Because such data may be excluded, the 3-hour average to determine compliance need not consist of *consecutive* 1-hour emission rates.

   (e) ~~*Power Augmentation Mode.* In event of a CEMS malfunction or occurrence of excess emissions while operating in the power augmentation mode, the permittee shall immediately cease power augmentation and revert to normal gas firing or shut down the combustion turbine.~~Note: There is no basis for this condition in the Department's rules. Power augmentation and peak firing should be treated as any other operating condition that provides for circumstances involving CEMS malfunctions.

   [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-212.400(BACT), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

RECORDS

27. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    (a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods.

    (b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

    These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan), natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

    (a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

    (b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

    (c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of Specific Condition 27 (40 CFR 60.334(b)(2)), provided:

        (1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

        (2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

        (3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

    This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d). [40 CFR 60, Subpart GG; Applicant Request]

29. Monthly Operations Summary: ~~By the fifth calendar day of each month, t~~The permittee shall record the hours of each mode of operation and the fuel consumption for each combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. ~~Information recorded and stored as an electronic file shall be available for inspection and printing within at least one day of a request from the Compliance Authority.~~ [Rule 62-4.160(15), F.A.C.]Note: The requirements for recording information by the fifth day of each month and submittal of information at least one day of a request goes beyond the "reasonable time" stated in the rule. Moreover, the reporting requirements of both the NSPS and Acid Rain Program govern the timeframes for submittal of information.

REPORTS

30. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, periods of startup, shutdown and malfunction shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. Within 30 days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS (DRAFT)

FUEL HEATERS / STORAGE TANK

This section of the permit addresses the following new emissions units.

EU ID No.	Emission Unit Description
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 5A and 5B.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb : Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE RESTRICTIONS

3. Equipment: The permittee is authorized to install, operate, and maintain the following emissions units and supporting equipment: two gas fuel heaters fired solely with natural gas (23.71 mmBTU per hour) designed to heat the natural gas supplied to simple cycle combustion turbines 5A and 5B; and one 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to simple cycle combustion turbines 8~~5~~A and 8~~5~~B. [Applicant Request]

4. Hours of Operation: The hours of operation for the gas fuel heaters and distillate oil storage tank are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS PERFORMANCE STANDARDS

5. Visible Emissions: Visible emissions of 10~~5~~% opacity or less from the gas fuel heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are greater than 10~~5~~% opacity, the permittee shall investigate the cause and take the necessary corrective actions. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

RECORDS

6. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual amount of natural gas fired in the gas fuel heaters and the annual throughput of distillate oil for the storage tank . [Rule 62-210.370(3), F.A.C.]

7. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

INTEROFFICE MEMORANDUM

Date: 12-May-2000 01:19pm
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)

Subject: Re: Correction to FPL Martin Public Notice

Thanks Jeff,

I've told the Okeechobee News to hold off publishing the Public Notice until we have a chance to talk. I'm meeting with Wanda Parker-Garvin at 1:30 Tuesday....that meeting should take no more than 1-1/2 hours; I should be able to meet with you around 3:30 or earlier. If you want to invite Al, that would be fine also.

- Rich

"Jeff Koerner TAL 850/414-7268 GIC 069" <Jeff.Koerner@dep.state.fl.us> on 05/11/2000 04:23:16 PM

To: "Rich_Piper" <Rich_Piper@fpl.com>
cc: "Alvaro Linero TAL" <Alvaro.Linero@dep.state.fl.us>

Subject: Re: Correction to FPL Martin Public Notice

Rich,

Regarding a meeting for Tuesday the 16th, if you want to keep it on a "drop by" basis after noon, that's fine. I'm in Room 145 in Lucky Suite #13 across the courtyard from Suite #4. I'm usually here until 4:00, but can stay later if we need to. Remember, substantial changes to a Draft Permit require a new Public Notice.

Thanks!

Jeff

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 11-May-2000 04:23pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Rich_Piper (Rich_Piper@fpl.com)
CC: Alvaro Linero TAL (LINERO_A)

Subject: Re: Correction to FPL Martin Public Notice

Rich,

Regarding a meeting for Tuesday the 16th, if you want to keep it on a "drop by" basis after noon, that's fine. I'm in Room 145 in Lucky Suite #13 across the courtyard from Suite #4. I'm usually here until 4:00, but can stay later if we need to. Remember, substantial changes to a Draft Permit require a new Public Notice.

Thanks!

Jeff

INTEROFFICE MEMORANDUM

Date: 11-May-2000 02:08pm
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)

Subject: Re: Correction to FPL Martin Public Notice

Thanks Jeff. I've made the correction. The ad should appear in the Okeechobee News on Sunday the 14th.

I can potentially meet with you on Tuesday afternoon, the 16th. I'm going to be in Tallahassee for a meeting at 1:30 with the DEP water folks in Twin Towers, but my flight home doesn't leave until 6:20, so I could drop by Magnolia courtyard when I get done at Twin Towers, if that works?
Some of the issues will need Kosky's input, and he's out of town at that time, but since I'll be in the area, if you're available, I could stop by.

Let me know.

- Rich

"Jeff Koerner TAL 850/414-7268 GIC 069" <Jeff.Koerner@dep.state.fl.us> on 05/11/2000 09:26:21 AM

To: "Rich Piper" <Rich_Piper@fpl.com>, "Ken Kosky" <kkosky@golder.com>
cc: "James Stormer" <jim_stormer@doh.state.fl.us>, "Isidore Goldman WPB" <Isidore.Goldman@dep.state.fl.us>

Subject: Correction to FPL Martin Public Notice

Rich,

Thanks! The correct District Office for the Martin Plant is the Southeast District Office and not the Central District Office. As you guessed, this remained from a previous project. Please revise the Public Notice to include the SED address, which is:

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue (P.O. Box 15425)
West Palm Beach, Florida 33416-5425

Telephone: 561/681-6600
Fax: 561/681-6755

I have also attached a revised elctronic version for your convenience. I will
not follow up with a hard copy unless you request one.

Please call if you need to schedule a meeting to discuss your comments on the
draft permit.

Jeff

(See attached file: 286d_INT.doc)

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL Date: 11-May-2000 09:26am

From: Jeff Koerner TAL
KOERNER_J

Dept:

Tel No:

To:	Rich Piper	(Rich_Piper@fpl.com)
To:	Ken Kosky	(kkosky@golder.com)
CC:	James Stormer	(jim_stormer@doh.state.fl.us)
CC:	Isidore Goldman WPB	(GOLDMAN_I @ A1 @ DEPWPB)

Subject: Correction to FPL Martin Public Notice

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I have also attached a revised elctronic version for your convenience. I will not follow up with a hard copy unless you request one.

Please call if you need to schedule a meeting to discuss your comments on the draft permit.

Jeff

To:	Rich Piper
To:	Ken Kosky
CC:	James Stormer
CC:	Isidore Goldman WPB

address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public ins~~pection during normal business hours~~, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holid~~ays, at~~:

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida, 32301 Telephone: 850/488-0114 Fax: 850/922-6979	Department of Environmental Protection Southeast District Office 400 North Congress Avenue (P.O. Box 15425) West Palm Beach, Florida 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6755

only revisions

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer ~~for this~~ project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, ~~Florida 32301~~, or call 850/488-0114, for additional information.

{Note: This document was revised on 05/11/00 to correct the District Office location from the Central District to the Southeast District.}

notice to be published in the newspaper

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 4, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

John M. Lindsay, Plant General Manager
Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: DEP File No. 0850001-008-AC (PSD-FL-286)
FPL Martin Plant
Addition of Two 170 MW Simple Cycle Peaking Combustion Turbines

Dear Mr. Lindsay:

Enclosed is one copy of the draft air construction permit to install two new simple cycle combustion turbines at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Department's Technical Evaluation and Preliminary Determination, Intent to Issue Air Construction Permit, and the Public Notice of Intent to Issue Air Construction Permit are also included.

The Public Notice of Intent to Issue Air Construction Permit must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/jfk

Enclosures

Z 341 355 281

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to John Lindsay	
Street & Number FP4L	
Post Office, State, & ZIP Code Indiantown, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-5-00 0850001-008-4C PSD-Fl-286	

PS Form **3800**, April 1995

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
John M. Lindsay
Plant Gen. Mgr.
FP4L Co - Martin Plant
PO Box 176
Indiantown, Fl
34956

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 5-8-00

C. Signature
X [signature]
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* Z 341 355 281

PS Form 38[illegible] [illegible]ipt 102595-99-M-1789

In the Matter of an
Application for Permit by:

John M. Lindsay, Plant General Manager
Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

ARMS Project No. 0850001-008-AC
PSD Permit No. PSD-FL-286
FPL Martin Power Plant
Emission Units 011 – 014
Martin County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of draft permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Florida Power and Light, applied on February 19, 2000 to the Department for an air construction permit to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Draft Permit authorizes the installation of two simple cycle, dual-fuel, General Electric Model PG7241(FA) combustion turbines-electrical generator sets, each having a generating capacity of 170 MW.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5-5-00 to the person(s) listed:

Mr. John M. Lindsay, FPL*
Mr. Richard G. Piper, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Tober 5-5-00
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

FPL Martin Power Plant
Martin County

Draft Permit No. 0850001-008-AC (PSD-FL-286)
Two New Simple Cycle Combustion Turbines
New Emissions Units 011 - 014

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power and Light (FPL) Company to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The applicant proposes to install of two simple cycle gas turbines, two natural gas fired fuel heaters, and a distillate oil storage tank. Each gas turbine is a General Electric Model PG7241(FA) combustion turbine-electrical generator set with a nominal generating capacity of 170 MW. A determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. Although this project is located at a plant subject to the Power Plant Siting Act, it is not subject to review under Section 403.506, F.S., because it provides for no expansion in steam generating capacity. The applicant's authorized representative is John M. Lindsay, Plant General Manager, for the FPL Martin Power Plant. The applicant's mailing address is P.O. Box 176, Indiantown, FL 34956.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry low-NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for *power augmentation* during peak demand periods, typically summer. The power augmentation mode is restricted to 500 of the allowable hours when firing only natural gas with CO and NOx emissions limited to 15 and 12 ppmvd corrected to 15% oxygen, respectively.

The following table summarizes the project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	Project Potential Annual Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	140	100	Yes	Yes
NOx	374	40	Yes	Yes
PM/PM_{10}	35	15	Yes	Yes
SAM	5	7	No	No
SO_2	67	40	Yes	Yes
VOC	14	40	No	No

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Florida Power and Light Company – Martin Plant

Addition of Two Simple Cycle Combustion Turbines
Emissions Units 011 - 014

Martin County

ARMS Facility ID No. 0850001

Project No. 0850001-008-AC

Permit No. PSD-FL-286

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

April 27, 2000

This document describes the overall project, discusses rule applicability, summarizes the determination of Best Available Control Technology, reports the air quality impacts, and makes a preliminary determination on the requested permitting action. It is organized in the following sections:

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

1.2 Reviewing and Processing Schedule

02/19/00 Department received the PSD air pollution construction permit application.

02/23/00 Department mailed copies to EPA Region 4 and the National Park Service

03/10/00 Department requested additional information (No. 1).

03/24/00 Department received additional information (No. 1).

04/06/00 Department requested additional information (No. 2).

04/10/00 Department received additional information (partial No. 2).

04/14/00 Department received additional information (remaining No. 2) from the applicant making application complete.

2.0 FACILITY INFORMATION

2.1 Facility Description

The existing FPL Martin Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the requested project will add two 170 MW simple cycle combustion turbines increasing the total nominal generating capacity to 2940 MW.

2.2 Facility Location

The existing facility is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46". This site is approximately 144 kilometers north of the Everglades National Park, a PSD Class I Area.

2.3 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.4 Regulatory Categories

Power Plant Siting: The existing facility is regulated pursuant to the Electric Power Plant and Transmission Line Siting Act. However, because no steam will be generated by this project, it is not subject to requirements of Chapter 403, Part II, F.S. or Chapter 62-17, F.A.C.

Title III – HAP: The existing facility is a major source of hazardous air pollutants. Emissions solely from the project do not exceed the major source thresholds for hazardous air pollutants. Therefore, a Section 112(g) case-by-case determination of Maximum Available Control Technology does not apply.

Title IV - Acid Rain: The existing facility is subject to Title IV, the federal Acid Rain program. The gas turbines will also be subject to the acid rain provisions.

Title V – Major Source: The existing facility is classified as a Title V major source of air pollution because emissions of at least one regulated air pollutant, such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, new projects must be reviewed for PSD applicability. Each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. requires a determination of Best Available Control Technology (BACT). For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: This project includes emissions units that are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

3.0 PROPOSED PROJECT

3.1 Project Description

The applicant, Florida Power and Light Company, proposes to install two new simple cycle combustion turbines, two gas-fired natural gas fuel heaters, a common distillate oil storage tank, and associated equipment at the existing FPL Martin Power Plant. Each combustion turbine consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 60 feet tall and 22 feet in diameter. Each unit is designed to produce a nominal 170 MW of electrical power fired with natural gas as the primary fuel and low sulfur distillate oil as a backup fuel. The applicant proposes to limit use of the gas turbines as "peaking units" by restricting the allowable operation to no more than 3390 hours per year per unit. Of this total, no more than 500 hours per year would occur when firing low sulfur distillate oil as a backup fuel. In addition, the applicant requests approval for "power augmentation" and "peaking" as authorized high power modes of operation when firing natural gas. The high power modes result in higher CO and NOx emissions than those for normal gas firing and are discussed in more detail under the NOx BACT Determination. Of the allowable 3390 hours per year, no more than 500 hours per year would occur when operating in the high power modes. The applicant proposes dry low-NOx (DLN) combustion technology to control nitrogen oxide emissions and combustion design with clean fuels to minimize emissions of other pollutants.

As a result of fuel combustion, this project will emit emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of CO, NOx, PM/PM_{10}, and SO_2 exceed the Significant Emissions Rates established in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, the Department must establish emissions standards that represent a determination of Best Available Control Technology (BACT) for these pollutants. The permit will also include emissions standards for VOC as a PSD-synthetic minor pollutant. This document presents a detailed description of the PSD applicability analysis and BACT determination. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanying the Department's Intent to Issue Permit package.

3.2 Project Emissions

Table 3.2 This table summarizes potential emissions increases and the resulting PSD applicability.

Pollutant	Proposed[a,c] PTE (Tons Per Year)	Draft Permit[b,c] PTE (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	170	140	100	Yes	Yes
NOx	423	374	40	Yes	Yes
PM	38	35	25	Yes	Yes
PM_{10}	38	35	15	Yes	Yes
SAM	5	5	7	No	No
SO_2	64	67	40	Yes	Yes
VOC	13	14	40	No	No

[a] - For each gas turbine, the potential emissions were based on: 2390 hours per year of normal gas firing, 500 hours per year of gas firing in the "high power modes", 500 hours per year of distillate oil firing as a backup fuel, and the "annual" hourly emission rates for an inlet air temperature of 59° F.

For each gas turbine, the potential emissions were based on: 2390 hours per year of normal gas firing, 500 hours per year of gas firing in the power augmentation mode, 500 hours per year of distillate oil firing as a backup fuel, and the maximum mass emission rates specified in the draft permit based on an inlet air temperature of 35° F.

Potential emissions also include minor emissions from two gas fuel heaters and a distillate oil tank.

As shown, the proposed combustion turbine project is subject to PSD review and determinations of Best Available Control Technology (BACT) for CO, NOx, PM/PM_{10} and SO_2.

4.0 RULE APPLICABILITY

4.1 PSD Review

As previously discussed, the existing facility is considered a PSD major source and is located in Martin County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). Therefore, the project is subject to a review for the Prevention of Significant Deterioration of Air Quality accordance with Rule 62-212.400, F.A.C. The PSD review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each significant pollutant exceeding the Significant Emission Rates defined in Table 212.400-2, F.A.C. For this project, a BACT determination is required for CO, NOx, PM/PM_{10} and SO_2. The second part requires an Air Quality Analysis consisting of: air dispersion modeling to estimate the resulting ambient pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4.2 State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following state rules and regulations of the Florida Administrative Code.

Citation	Description
Chapter 62-4	Permitting Requirements
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution
Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

4.3 Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Citation	Description
40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 52.166	Prevention of Significant Deterioration
40 CFR 60	NSPS Subpart Kb - Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984
40 CFR 60	NSPS Subpart GG – Stationary Gas Turbines
40 CFR 60	Subpart A, General Provisions for NSPS Sources
40 CFR 60	Applicable Appendices
40 CFR 72	Acid Rain Permits
40 CFR 73	Allowances
40 CFR 75	Monitoring
40 CFR 77	Acid Rain Program - Excess Emissions

5.0 SUMMARY OF BACT DETERMINATION

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry low-NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for *power augmentation* during peak demand periods, typically summer. The power augmentation mode is restricted to 500 hours and only when firing natural gas with CO and NOx emissions limited to 15 and 12 ppmvd corrected to 15% oxygen, respectively. A detailed analysis of the BACT Determination is presented in Appendix BD of the draft permit included with the Department's Intent to Issue Permit. The following table summarizes the resulting emissions standards.

Table 5-A. Summary of Emissions Standards

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines (5A and 5B)

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
SO_2, PM/PM_{10}	Gas, All Modes	1 grain per 100 SCF of natural gas (PM estimated < 0.003 grains/dscf) Visible emissions ≤ 5% opacity	Fuel records None Base load; initial and annual tests
	Oil	0.05% sulfur by weight distillate oil (PM estimated < 0.003 grains/dscf) Visible emissions ≤ 10% opacity	Fuel records None Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits

Note: *The mass emission limits for gas and oil firing were based on 100% base load, maximum heat input, fuel higher heating values, compressor inlet conditions of 35° F and 20% RH for normal firing, and compressor inlet conditions of 80-95° F and 60% RH for gas firing with power augmentation.*

6.0 AIR QUALITY ANALYSIS

6.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: CO, NOx, PM_{10} and SO_2. NOx, PM_{10} and SO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

The applicant's initial CO, NOx, PM_{10} and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for CO, NOx, PM_{10} and SO_2; and
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model 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 West Palm Beach, Florida (surface and upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

6.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst load conditions the ISCST3 model was used to evaluate dispersion of emissions from the simple cycle facility for three loads (50, 75% and 100%) and three seasonal operating conditions (summer, winter, and average) for each fuel type. Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If modeling at worst load conditions shows significant impacts, additional multi-facility modeling is required to determine the project's impacts on existing air quality and any applicable AAQS or PSD increments.

Receptors were placed around the facility, which is located in a PSD Class II area. The receptor grid for predicting maximum concentrations in the vicinity of the project was a polar receptor grid that contained 24 rings with each ring containing 36 radial receptors spaced 10° apart. The dimensions of the grid were centered upon the proposed combustion turbines. Along each radial, receptors were located at distances ranging from 200 m out to 30 km. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility. For the Class I analysis, the maximum concentrations were predicted at 53 receptors surrounding the PSD Class I area of the Everglades National Park (ENP). These receptors have been provided by the FDEP for use in previous applications. The table below shows the results of the significant impact modeling.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.04	1	NO
	24-hour	0.5	5	NO
	3-hour	2.8	25	NO
PM_{10}	Annual	0.009	1	NO
	24-hour	0.12	5	NO
CO	8-hour	2	500	NO
	1-hour	11	2000	NO
NO_2	Annual	0.14	1	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (ENP)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.0035	0.1	NO
	24-hour	0.135	0.2	NO
	3-hour	0.657	1.0	NO
PM_{10}	Annual	0.0008	0.2	NO
	24-hour	0.03	0.3	NO
NO_2	Annual	0.013	0.1	NO

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project.

6.4 Impacts Analysis

Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with a conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for SO_2, PM_{10}, CO and NOx, as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels, which are in turn less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NOx and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species.

A regional haze analysis that used the CALPUFF modeling system in a screening mode otherwise known as CALPUFF Lite was performed. CALPUFF is a long-range transport model recommended by the National Park Service (NPS) for use in regional haze analyses because of its ability to handle atmospheric chemical transformations as well as wet and dry deposition. The results of the CALPUFF Lite modeling analysis indicated a predicted change in visibility of 4.83%, which is less than the NPS threshold of 5%. Therefore, the proposed project is not predicted to have an adverse impact on visibility and regional haze in the ENP.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require few new permanent employees, which will cause no significant impact on the local area.

7.0 CONCLUSION

The Public Service Commission has determined that a number of power projects will be needed over the next few years to meet the rising electrical power needs throughout the State of Florida. This project is a response to predicted statewide growth and an effort to meet the required reserve capacity. The proposed project has a small overall physical "footprint," low water requirements, and low air emissions per unit of electric power generated compared to similar projects with intermittent operation.

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. This determination is based on the technical review of the complete PSD application, reasonable assurances provided by the applicant, the preliminary determination of Best Available Control Technology (BACT), and the conditions specified in the Draft Permit. Jeff Koerner is the permitting engineer responsible for reviewing the application, recommending the BACT determination, and drafting the permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for this project.

PERMITTEE:

Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911
Expires:	June 1, 2002

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality. The permit authorizes installation at the existing power plant of two simple cycle, 170 MW combustion turbines with electrical generator sets fired primarily with natural gas.

The project will be constructed at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46".

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	-	Terminology
Appendix BD	-	Department's BACT Determinations
Appendix E	-	Emissions Standards Summary
Appendix GC	-	Construction Permit General Conditions
Appendix GG	-	NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	-	CEMS Excess Emissions Report

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

Date: ____________________

FACILITY DESCRIPTION

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	Emission Unit Description
011	Simple Cycle Unit No. 5A: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
012	Simple Cycle Unit No. 5B: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 5A and 5B.

REGULATORY CLASSIFICATION

HAPs: Based on the Title V permit, the existing facility is a major source of hazardous air pollutants (Title III). This project is not, in and of itself, major for HAPs.

Acid Rain: The existing facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: The existing facility is a Title V major source of air pollution because potential emissions of at least one pollutant such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceed 100 tons per year.

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, each new project requires a PSD applicability review. For each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C., a determination of Best Available Control Technology (BACT) is required. For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: Emissions units are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 02/19/00 and all related correspondence.

The following conditions apply to all emissions units and activities defined for this project.

GENERAL REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.
2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, 400 North Congress Avenue, P.O. Box 15425, West Palm Beach, Florida 33416-5425. The phone number is 561/681-6600 and the fax number is 561/681-6755.
3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.
4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]
8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]
9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for routine operation of the permitted emissions units. The permittee shall apply for and receive a Title V operation permit prior to expiration of this permit. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Applicable Test Procedures

    (a) *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)1. and 2., F.A.C.]

(b) *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

(c) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

20. Determination of Process Variables

(a) *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

21. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS

22. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

REPORTS

23. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

24. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

COMBUSTION TURBINES

This section of the permit addresses the following new emissions units.

EU ID No.	Common Emission Unit Description
011 012	Simple Cycle Units Nos. 5A and 5B: Each unit consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 60 feet tall and 22 feet in diameter, and associated support equipment. *Natural Gas*: When firing 1858 mmBTU (HHV) per hour of natural gas, each unit produces a maximum 182 MW of power at a compressor inlet air temperature of 35° F. Dry low-NOx (DLN) combustion technology will control NOx emissions. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,461,000 acfm at 1095° F. *Distillate Oil*: When firing 1965 mmBTU per hour of low sulfur distillate oil as a backup fuel for up to 500 hours per year, each unit produces a maximum 189 MW of power at a compressor inlet air temperature of 35° F. Water injection will control NOx emissions. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,539,000 acfm at 1075° F. *Power Augmentation Mode*: When injecting steam during power augmentation mode for up to 500 hours per year, each unit produces a maximum 180 MW of power at a compressor inlet air temperature greater than 59° F. Emissions of CO and NOx from the dry low-NOx combustion system will be slightly higher during the power augmentation mode. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,403,000 acfm at 1130° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}) and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (a) *Subpart A, General Provisions*, incuding:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) *Subpart GG, Standards of Performance for Stationary Gas Turbines* are identified in *Appendix GG* of this permit. These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

PERFORMANCE RESTRICTIONS

3. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines with electrical generator sets, each designed to produce a nominal 170 MW of electrical power. [Applicant Request; Design]

4. Permitted Capacity: The heat input to each combustion turbine from normal gas firing shall not exceed 1858 mmBTU per hour based on the following: 100% base load (182 MW); a higher heating value (HHV) of 23,127 BTU/lbm for natural gas; and compressor inlet air conditions of 35° F and 20% RH. The heat input to each combustion turbine from firing distillate oil shall not exceed 1965 mmBTU per hour based on the following: 100% base load (189 MW); a higher heating value (HHV) of 19,365 BTU/lbm for distillate oil; and compressor inlet air conditions 35° F and 20% RH. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

5. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be considered a phased project and will require a new PSD permit as if the existing project had never been constructed (no netting). Note: At the time of permit issuance, selective catalytic reduction was capable of achieving a NOx emission rate of 3.5 ppmvd corrected to 15% oxygen. [Rule 62-212.400(6)(b), F.A.C.; 40 CFR 51.166(j)(4)]

6. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by this permit. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in this permit. [Application; Rule 62-210.200(PTE), F.A.C.]

7. Power Augmentation Mode: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 500 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating power augmentation, the operator shall log the date, time, and new mode of operation. Power augmentation when firing distillate oil is prohibited. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

8. Hours of Operation: Each combustion turbine shall operate no more than 3390 hours during any consecutive 12 months. Of this total, each unit shall not exceed 500 hours of power augmentation during any consecutive 12 months and 500 hours of distillate oil firing during any consecutive 12 months. The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each mode of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

9. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors

shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS CONTROLS

10. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, combustion temperatures, heat input, and fully automated startup, shutdown, and cool-down. [Design; 62-212.400(BACT), F.A.C.]
11. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine . [Design; Rule 62-212.400(BACT), F.A.C.]
12. Tuning: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. [Design; Rule 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix E of this permit.}

13. Carbon Monoxide (CO)
    (a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, CO emissions from each combustion turbine shall not exceed 32.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.
    (b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher.
    (c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

    The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]
14. Nitrogen Oxides (NOx)
    (a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

(c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332]

15. Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2)

(a) *Fuel Specifications.* Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

(b) *VE Standard.* When firing natural gas with or without power augmentation, visible emissions from each combustion turbine shall not exceed 5% opacity, based on a 6-minute average. When firing distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

16. Volatile Organic Compounds (VOC)

(a) *Gas Firing With or Without Power Augmentation*: When firing natural gas, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

(b) *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the

calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

18. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:
    (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.
    (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.
    (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods. [Design and Rule 62-210.700(1) and (5), F.A.C.]
    (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For excess NOx emissions due startup, shutdown, and documented malfunction during any calendar day, two hourly averages of monitoring data may be excluded from the continuous NOx compliance demonstration. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR 60.40a(b)]
20. Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C.
    (a) EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources
    (b) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources
    (c) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources
    (d) EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
    (e) EPA Methods 25 or 25A - Determination of Volatile Organic Concentrations *{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.}*

    No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [40 CFR 60, Appendix A; Rule 62-204.800, F.A.C.]
21. Initial Tests Required: Initial performance tests to demonstrate compliance with each emission standard for normal gas firing, gas firing with power augmentation, and backup distillate oil firing shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of each emissions unit. Initial performance tests shall be conducted for CO, NOx, VOC and visible emissions. Tests for CO, NOx, and VOC shall be conducted concurrently. NOx performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and emissions data also converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

22. Annual Performance Tests: Annual performance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup distillate oil firing. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). CO and NOx performance tests shall be conducted concurrently. If conducted at permitted capacity, NOx emissions data collected during the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test.

    (a) If no distillate oil was fired during the previous 24 months of operation (other than for purposes of testing), the annual performance tests when firing distillate oil shall not be required.

    (b) If power augmentation was not used during the previous 24 months of operation (other than for purposes of testing), the annual performance tests for that mode of operation shall not be required.

    [Rule 62-297.310(7)(a)4., F.A.C.]

23. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for each combustion turbine to demonstrate compliance with the CO, NOx, VOC and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup oil firing. Tests for CO, NOx, and VOC emissions shall be conducted concurrently. All tests shall be conducted within the 12 months prior to renewing the air operation permit. [Rule 62-297.310(7)(a)3., F.A.C.]

24. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment, including the replacement of dry low-NOx combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine. [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

25. Combustion Turbine Testing Capacity

    (a) Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines.

    (b) Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.

    (c) Performance tests for gas firing with the power augmentation mode shall be conducted when operating each combustion turbine at a heat input rate of 100% or greater than that predicted by the manufacturer to achieve a maximum base load rate adjusted for the compressor inlet air conditions. The steam injection rate shall be no lower than 90% of the maximum steam injection rate.

    [Rule 62-297.310(2), F.A.C.; 40 CFR 60.335]

CONTINUOUS MONITORING REQUIREMENTS

26. NOx CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NOx monitoring devices shall comply with the certification requirements, quality assurance procedures, and all other provisions of Performance Specifications 2 and 3 as defined in Appendix B of 40 CFR 60 and the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of the following information: CEM equipment specifications, manufacturer, model, type, calibration and maintenance needs, and the proposed location.

    (a) *Installation.* Each CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and Appendix F of 40 CFR 60.

    (b) *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Each valid 1-hour average shall be calculated using at least two valid data points at least 15 minutes apart.

    (c) *Data Reporting.* Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 3-hour block average. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 3-hour block of valid hourly emission rates. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required by this permit.

    (d) *Data Exclusion.* Unless prohibited by 62-210.700 F.A.C., valid hourly emission rates shall not include periods of excess emissions due to start up, shutdown, or documented malfunction as described and limited under the excess emissions requirements of this permit. Because such data may be excluded, the 3-hour average to determine compliance need not consist of *consecutive* 1-hour emission rates.

    (e) *Power Augmentation Mode.* In event of a CEMS malfunction or occurrence of excess emissions while operating in the power augmentation mode, the permittee shall immediately cease power augmentation and revert to normal gas firing or shut down the combustion turbine.

    [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-212.400(BACT), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

RECORDS

27. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    (a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan), natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

    (a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

    (b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

    (c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2), provided:

        (1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

        (2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

        (3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

    This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d). [40 CFR 60, Subpart GG; Applicant Request]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of each mode of operation and the fuel consumption for each combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

30. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, periods of startup, shutdown and malfunction shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. Within 30 days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

FUEL HEATERS / STORAGE TANK

This section of the permit addresses the following new emissions units.

EU ID No.	Emission Unit Description
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 5A and 5B.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb : Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE RESTRICTIONS

3. Equipment: The permittee is authorized to install, operate, and maintain the following emissions units and supporting equipment: two gas fuel heaters fired solely with natural gas (23.71 mmBTU per hour) designed to heat the natural gas supplied to simple cycle combustion turbines 5A and 5B; and one 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to simple cycle combustion turbines 5A and 5B. [Applicant Request]

4. Hours of Operation: The hours of operation for the gas fuel heaters and distillate oil storage tank are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS PERFORMANCE STANDARDS

5. Visible Emissions: Visible emissions of 5% opacity or less from the gas fuel heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are greater than 5% opacity, the permittee shall investigate the cause and take the necessary corrective actions. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

RECORDS

6. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual amount of natural gas fired in the gas fuel heaters and the annual throughput of distillate oil for the storage tank . [Rule 62-210.370(3), F.A.C.]

7. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION IV.

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

°F	-	Degrees Fahrenheit
DEP	-	State of Florida, Department of Environmental Protection
DARM	-	Division of Air Resource Management
EPA	-	United States Environmental Protection Agency
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
SOA	-	Specific Operating Agreement
UTM	-	Universal Transverse Mercator
CT	-	Combustion Turbine
HRSG	-	Heat Recovery Steam Generator
DLN	-	Dry Low-NOx Combustion Technology
SCR	-	Selective Catalytic Reduction
OC	-	Oxidation Catalyst Technology for CO Control

RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example:	[Rule 62-213.205, F.A.C.]	
Where:	62	- identifies the specific Title of the F.A.C.
	62-213	- identifies the specific Chapter of the F.A.C.
	62-213.205	- identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example:	Facility ID No. 099-0001	
Where:	099	- identifies the specific county location
	0221	- identifies the specific facility

New Permit Numbers:

Example:	Permit No. 099-2222-001-AC or 099-2222-001-AV	
Where:	AC	- identifies the permit as an Air Construction Permit
	AV	- identifies the permit as a Title V Major Source Air Operation Permit
	099	- identifies the specific county that project is located in
	2222	- identifies the specific facility
	001	- identifies the specific permit project

Old Permit Numbers:

Example:	Permit No. AC50-123456 or AO50-123456	
Where:	AC	- identifies the permit as an Air Construction Permit
	AO	- identifies the permit as an Air Operation Permit
	123456	- identifies the specific permit project

FPL Martin Power Plant
Martin County

Draft Permit No. 0850001-008-AC (PSD-FL-286)
New EUs 011 - 014: Addition of Two New Simple-Cycle Gas Turbines

1.0 EXISTING FACILITY

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

2.0 PROJECT DESCRIPTION

The applicant, Florida Power and Light, proposes to install two new simple cycle combustion turbines; two gas-fired natural gas fuel heaters, a common distillate oil storage tank, and associated equipment at the existing FPL Martin Power Plant. Each combustion turbine consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 60 feet tall and 22 feet in diameter. Each unit is designed to produce a nominal 170 MW of electrical power fired with natural gas as the primary fuel and low sulfur distillate oil as a backup fuel. The applicant proposes to limit use of the gas turbines as "peaking units" by restricting the allowable operation to no more than 3390 hours per year per unit. Of this total, no more than 500 hours per year would occur when firing low sulfur distillate oil as a backup fuel. In addition, the applicant requests approval for "power augmentation" and "peaking" as authorized high power modes of operation when firing natural gas. The high power modes result in higher CO and NOx emissions than those for normal gas firing and are discussed in more detail under the NOx BACT Determination. Of the allowable 3390 hours per year, no more than 500 hours per year would occur when operating in the high power modes. The applicant proposes dry low-NOx (DLN) combustion technology to control nitrogen oxide emissions and combustion design with clean fuels to minimize emissions of other pollutants.

As a result of fuel combustion, this project will emit emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of CO, NOx, PM/PM_{10}, and SO_2 exceed the Significant Emissions Rates established in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, the Department must establish emissions standards that represent a determination of Best Available Control Technology (BACT) for these pollutants. The permit will also include emissions standards for VOC as a PSD-synthetic minor pollutant. This document presents a detailed description of the PSD applicability analysis and BACT determination. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanied the Department's Intent to Issue Permit package.

3.0 PSD APPLICABILITY REVIEW

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program as approved by the EPA and defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with a National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. An existing facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or

- 100 tons per year or more of any regulated air pollutant and it falls under one of the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C.

The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because potential emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. For new projects at PSD major sources, each pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant in accordance with Rule 62-212.400, F.A.C. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to implement BACT for several "significant" regulated pollutants.

This project will be located in Martin County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The following table summarizes the potential emissions increases and PSD applicability for this new project based on information provided by the applicant.

Pollutant	Project Potential Emissions[a] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	Subject To BACT?
CO	170	100	Yes	Yes
NOx	423	40	Yes	Yes
PM	38	25	Yes	Yes
PM_{10}	38	15	Yes	Yes
SAM	5	7	No	No
SO_2	64	40	Yes	Yes
VOC	13	40	No	No

a - For each gas turbine, potential emissions were based on 2390 hours per year of normal gas firing, 500 hours per year of gas firing with high power mode, and 500 hours per year of distillate oil firing as a backup fuel. Potential emissions also include emissions from two gas fuel heaters and a distillate oil tank.

Therefore, the proposed combustion turbine project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM/PM_{10}, and SO_2.

4.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination and shall also give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants). The combustion turbine project is subject to 40 CFR 60, Subpart GG, a New Source Performance Standards (NSPS) which regulates Stationary Gas Turbines, adopted by reference in Rule 62-204.800, F.A.C. There are no applicable NESHAP regulations.

The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

5.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

For this project, the following pollutants are subject to a BACT determination: CO, NOx, PM/PM_{10}, and SO_2. The applicant proposed control strategies for these pollutants in the PSD permit application. Besides the information submitted by the applicant, the Department also relied on the following information:

- The National Park Service made no adverse comments on the application;
- EPA Region 4 made no adverse comments on the application;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical product literature regarding DLN emissions, the gas turbine control system, and evaporative cooling;
- Englehard equipment cost quotes for a CO oxidation catalyst and selective catalytic NOx reduction;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- Proposed AP-42 changes to Section 3.1 for gas turbines (10/96 draft and 5/98 revision);
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;
- Goal Line Environmental Technology Website: http://www.glet.com; and
- Catalytica Website – www.catalytica-inc.com

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. The following table provides a summary of the most recent determinations similar projects in the United States.

Brief Summary of Recent CO, NOx, and PM BACT Determinations for Similar Simple Cycle, Gas Fired Units

Project Location	Unit MW	Date	Technology	CO Limit ppmvd @ 15% O2	NOx Limit Ppmvd @ 15% O2	PM Limit	Comments
FPL Martin Plant, FL	170	04/00, D	DLN	9 15 w/PA	10, 3-hr CEMS 12 w/PA, 3-hr CEMS	5% Opacity	500 hr/yr oil firing 500 hr/yr PA mode
Palmetto Power, FL	170 MW WH 501FD	03/00, D	DLN	Initial: 25 (12 months) Final: 15	15, 3-hr CEMS	10% opacity	No oil firing
Desoto Power, FL	170 MW GE 7FA	03/00, D	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Shady Hills Pasco, FL	170 MW GE 7FA	01/00, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Vandolah Hardee, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Oleander Brevard, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
JEA Baldwin, FL	170 MW GE 7FA	10/99, P	DLN	12	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Reliant Osceola, FL	170 MW GE 7FA	11/99, P	DLN	10.5	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
TEC Polk Power, FL	165 MW GE 7FA	10/99, P	DLN	15	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Dynegy Heard, GA	170 MW WH 501F	10/99, P	DLN	25	15	10% opacity	No oil firing
Tenaska Heard, GA	170 MW GE 7FA	12/98, P	DLN	15	15	Unknown	720 hr/yr oil firing
Calvert City, KY	170 MW GE 7FA	1999, D	WI	30, base load 90, other	25	Unknown	? hr/yr oil firing
Mid-GA Cogen	119 MW WH 501D5A	06/98, O	DLN, SCR	10	9	18 lb/hr	? hr/yr oil firing
Dynegy Reidsville, NC	180 MW WH 501F	06/99, P	DLN	25	Initial: 25 Final: 15 (by 2002)	6 lb/hr	1000 hr/yr oil firing
Lyondell Harris, TX	160 MW WH 501F	11/99, P	DLN	25	25	Unknown	No oil firing
Southern Energy, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
RockGen Cristiana, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
Lakeland, FL	250 MW WH 501G	07/98, P	DLN, HSCR	25	Initial: 25 Final: 9 (by 2002)	10% opacity	250 hr/yr oil firing

Abbreviations:

Manufacturer	Date	Controls	Other
GE – General Electric	D – Draft	DLN – Dry Low-NOx	LAER – Lowest Achievable Emission Rate
WH – Westinghouse	O – Operating	HSCR – Hot Selective Catalytic Reduction	CEMS – Continuous Emissions Monitoring System
ABB – Asea Brown Boyan	P – Permitted	SCR - Selective Catalytic Reduction	PA – Power Augmentation (Steam Injection)
		WI = Water or Steam Injection	

Notes: All data presented is for > 100 MW simple cycle units firing natural gas. The Lakeland project is permitted for combined cycle operation with separate limits for simple cycle mode. The remaining projects are restricted to intermittent simple cycle operation.

5.1 NITROGEN OXIDES (NOx)

{Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NOx Emissions from Stationary Gas Turbines. Specific project information is included where applicable.}

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures associated with combustion turbines, the primary pollutant of concern is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @ 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions in the range of 150 ppmvd @ 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from stationary gas turbines is 75 ppmvd corrected to 15% oxygen and ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically-bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures due to the inherently lower thermal NOx portion. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold.day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Most new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to 100% of base load. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, usually less than 32° F.

Identification of Control Technologies

The following technologies were identified as potentially applicable for the control of NOx from combustion turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd @15% O_2.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the

same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for dry low-NOx combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%. DLN technology research for oil firing continues.

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850°F. SCR is a commercially available, demonstrated control technology currently employed on several combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd) with control efficiencies up to 98%.

"Hot" Selective Catalytic Reduction (SCR): Due to temperature limitations of conventional SCR catalysts, vendors have developed specially formulated catalysts designed to further the reduction reaction at temperatures up to 1025°F. Also, cooling air can be added to reduce the gas temperatures to the appropriate design range. Hot SCR can deliver NOx control efficiencies of 70% to 95%.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For boilers, SNCR has achieved control efficiencies in the 40% to 60% range.

Non-Selective Catalytic Reduction (NSCR): NSCR uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor in exhaust gas streams containing less than 3% oxygen. This technology has only been applied to automobiles and stationary reciprocating engines with variable control efficiencies.

SCONOx™: This technology is a NOx and CO control system offered by Goal Line Environmental Technologies and ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. The required operating

temperature range is between 300°F and 700°F which requires a HRSG for use with a gas turbine. SCONOx™ can achieve control efficiencies in the 90% to98% range.

XONON™: This is an emerging technology that partially burns fuel in a low temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature and NOx formation followed by flame-less catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but will be specific to each manufacturer and model of gas turbine. It is anticipated that control efficiencies will be in the 80% to 95% range.

Applicant's Proposed NOx Controls

For a simple cycle gas turbine, the applicant recognized "hot" selective catalytic reduction as the top control option followed by dry low-NOx (DLN) combustion technology and water injection. For this project, General Electric guaranteed NOx emissions of 9 ppmvd @ 15% oxygen with DLN technology for gas firing and 42 ppmvd @ 15% oxygen for oil firing with water injection. The applicant estimated that hot SCR could reduce these emissions rates to 4 ppmvd @ 15% oxygen for gas firing with DLN and 16 ppmvd @ 15% oxygen for oil firing with water injection. However, the applicant makes the following claims regarding additional adverse impacts.

Energy Impacts: Hot SCR would result in a pressure loss across the catalyst resulting in an energy penalty of approximately 0.5%. Significant energy costs are associated with operating the hot SCR system. The lost energy would be equivalent to 370,000 mmBTU per year or about 37 mmCF per year of natural gas.

Environmental Impacts: The maximum predicted NOx concentrations resulting from DLN technology are well below the PSD increment of 25 ug/m^3 (annual average), the AAQS of 100 ug/m^3 and less than 20% of the significant impact level. Additional NOx reduction from requiring hot SCR would not be significant. Hot SCR would generate additional emissions of ammonia (> 47.7 tons per year per unit) and ammonium sulfates (>6.6 tons per year per unit). Power lost to the hot SCR system would have to be generated by other less efficient units resulting in increased emissions. CO_2 emissions would greatly increase as a result of hot SCR. Spent catalyst may have to be handled and treated as hazardous wastes. Ammonia handling and storage involves inherent risks and safety issues.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of hot SCR would result in capital costs of $5,189,813 and annualized costs of $1,640,906 per year. The applicant assumed a hot SCR system would remove an additional 127 tons of NOx per year (4 ppmvd @ 15% O_2 and 61% control efficiency) over a DLN only system at 10.5 ppmvd @15% O_2. This resulted in an incremental cost effectiveness for hot SCR of $12,943 per ton of NOx removed.

The applicant rejected hot SCR primarily based on unreasonable costs associated with controlling the low available tonnage of NOx emissions available from this project. This is primarily due to the inherently low emissions of the General Electric Model PG7241(FA) gas turbine as well as the applicant's request to restrict operation to that of a peaking unit (3390 hours per year). Therefore, the applicant proposed the following NOx limit as BACT for this project:

Applicant's Proposed NOx BACT

Normal Gas Firing Mode: 10.5 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 42.0 ppmvd @ 15% O_2 achieved by water injection

The applicant concludes by stating that DLN combustion provides the most cost effective alternative, is pollution preventing, results in low ambient impacts, and is consistent with recent BACT determinations for similar simple cycle combustion turbines made by Florida and other states.

Department's NOx BACT Determination

The Department rejected several previously mentioned control options for the following reasons.

- *Conventional Selective Catalytic Reduction (SCR)* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (850° F) for this technology.
- *Selective Non-Catalytic Reduction (SNCR)* was rejected because the gas turbine exhaust temperature of 1100°F is below the design limit (1600° F) for this technology.
- *Non-Selective Catalytic Reduction (NSCR)* was rejected because the oxygen content of the combustion turbine exhaust (13% to 15%) is above the design limit (3%) for this technology.
- *SCONOx*™ was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (700° F) for this emerging technology.
- *XONON*™ because this emerging technology is model-specific and not yet commercially available for the General Electric Model PG7241(FA).

The Department also recognizes hot selective catalytic reduction (hot SCR) combined with dry low-NOx (DLN) combustion technology as the top control option followed DLN technology alone, and water injection for oil firing. However, the Department disagrees with several of the applicant's statements regarding adverse impacts.

Energy Impacts: Installation of hot SCR *would* result in a total energy penalty of approximately 0.5% mostly due to the pressure drop across the catalyst bed. For SCR systems, EPA (1993) bases energy consumption to operate the SCR system on the pressure drop, neglecting other energy costs.

Environmental Impacts: The Department gives no consideration to the applicant's comment that there is no environmental benefit from add-on controls because NOx levels are already below the PSD increments, significant impact levels and AAQS. Ambient impacts from the project are only considered in the air quality analysis and carry no weight in making a BACT determination. Hot SCR would result in some ammonia "slip" or emissions of unreacted ammonia. However, estimating ammonia, ammonia sulfate, and PM_{10} emissions based on 9-10 ppm is misleading. Manufacturers of SCR systems typically design and guarantee systems with a 9 to 10 ppm of ammonia slip, but this is based on the end of the catalyst life and is not representative of actual emissions. An operator would attempt to reduce ammonia slip whenever possible to reduce operating costs. Storage and handling of ammonia does present additional risks, but these risks can be safely managed as evidenced by the numerous existing SCR systems, industrial ammonia refrigeration systems, fertilizer plants, etc.

Economic Impacts: In general, the Department agrees that adding hot SCR to the General Electric Model PG7241(FA) gas turbine with DLN controls would result in a cost effectiveness in the range of $10,000 to $13,000 per ton of NOx removed. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also recognizes that the analysis is significantly influenced by three critical constraints: the applicant's request for simple cycle operation only, the applicant's request for restricted operation as peaking units (3390 hours per year per gas turbine), and the inherently low emissions of the General Electric Model PG7241(FA) gas turbine. Should the applicant ever request operation of these gas turbines as base load units, conversion to combined cycle operation, or the substitution of a another gas turbine model, it is essential that the NOx BACT determination be reevaluated.

Based on the above discussion, the Department also rejects hot SCR as not cost effective for the project as limited by the applicant's requests. Therefore, the dry low-NOx combustion technology designed into the General Electric Model PG7241(FA) is determined to represent the best available control technology for this project. Dry low NOx combustion is pollution preventing in nature, avoids emissions of several non-regulated pollutants such as ammonia, and is consistent with recent BACT determinations made in Florida and other states.

The Department evaluated the applicant's request for two "high power modes" of operation when firing natural gas, which included steam injection for power augmentation and raising the combustion reference temperature for additional peaking power. The high power modes can result in NOx emissions that are higher than the normal gas-firing mode. The Department accepts the request for limited steam injection, but rejects the request for "peaking" based on the following items:

- The applicant provided a manufacturer's guarantee of emissions performance during steam injection for power augmentation. No such guarantee was provided for the "peaking" mode.
- For the power augmentation mode, steam is injected between the combustor and the first stage turbine to increase mass flow with a corresponding increase in heat input resulting in additional power generation. It is important to note that the unit remains "tuned" for low NOx emissions, although steam injection may result in NOx emissions levels up to 12 ppmvd @ 15% O_2.
- For the peaking mode, the combustion reference temperature is apparently increased by altering parameters within the software of the automated gas turbine control system to allow a higher heat input for an increased volumetric flow. The higher temperature results in NOx emissions levels up to 15 ppmvd @ 15% O_2.
- The applicant estimated that there would be a 6% "degradation" of the unit due to the high power modes of operation. Degradation was defined as, "... a lower heat rate with wear of turbine components potentially allowing higher heat input and mass flow.".
- The applicant requested the ability to fire low sulfur distillate oil as a backup fuel for 500 hours per year with NOx emissions controlled to 42.0 ppmvd @ 15% O_2 by water injection.
- The applicant also requested a NOx emissions standard of 10.5 ppmvd @ 15% O_2 instead of the 9.0 ppmvd @ 15% O_2 guaranteed by the manufacturer.

Based on information in the application and the higher emissions standards requested by the applicant, there appears to be a concern that the combination of high power modes, coupled with operation as a peaking unit, will degrade the gas turbine beyond General Electric's guaranteed emissions rates. A review of recent BACT determinations for simple cycle combustion turbines indicates the lowest BACT determination for this model gas turbine to be 9.0 ppmvd @ 15% O_2. After consideration of the information provided and the applicant's specific requests, the Department establishes the following NOx standards as BACT for this project:

<u>NOx BACT Determination</u>

Normal Gas Firing: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average. (This is to ensure that the units remain tuned for maximum NOx reduction.)

Normal Gas Firing: 10.0 ppmvd @ 15% O_2 based on a 3-hour CEMS block average achieved by DLN combustion. (A slightly higher continuous emissions limit with a short-term average was established to compensate for operation as a peaking unit. The mass emissions limit will be based on 10 ppmvd @15% O_2 and the most recent projects for the Model PG7241(FA) gas turbine.)

Gas Firing With Power Augmentation: 12.0 ppmvd @ 15% O_2 based on a 3-hour CEMS block average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the power augmentation mode to allow maximum power generation during the hot summer months of high demand. Operation in this mode will be restricted to no more than 500 hours per year.)

Distillate Oil Firing: 42.0 ppmvd @ 15% O_2 based on a 3-hour CEMS block average achieved by water injection. (DLN combustion technology is ineffective when firing distillate oil as a backup fuel. Operation when oil firing with water injection will be restricted to no more than 500 hours per year.)

Corresponding mass emission limits will also be established for each mode of operation. The Department will include specific conditions in the permit to address the following items:

- Each combustion turbine shall operate only in simple cycle mode. Conversion to combined cycle operation will require a new determination of NOx BACT as if the project had not yet been built. This means that the emissions from the simple cycle gas turbines will not be allowed for use in a netting calculation.
- Each combustion turbine shall operate no more than 3390 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not fire oil for more than 500 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not operate in the power augmentation mode for more than 500 hours during any consecutive 12 months. To relax any of these conditions will require a new determination of NOx BACT as if the project had not yet been built. Again, this means that the emissions from the simple cycle gas turbines will not be allowed for use in a netting calculation.
- Each combustion turbine shall operate below 50% base load for no more than two hours per day.

This BACT determination is much more stringent than the standards of NSPS, Subpart GG. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. In addition, the permittee shall install, calibrate, operate, and maintain a certified NOx continuous emissions monitor (CEMS) to demonstrate continuous compliance with the BACT limits.

5.2 Carbon Monoxide (CO)

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion while operating the combustion turbine. In general, CO emissions are inversely proportional to NOx emissions for gas turbines. However, new advanced combustor designs have also been able to lower CO emissions concurrently with NOx emissions. It is noted that General Electric has guaranteed CO emissions performance for the Model PG7241(FA) at 9.0 ppmvd @ 15% O_2 for several projects.

Applicant's Proposed CO BACT

The applicant identified two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and efficient combustor design. An oxidation catalyst consists of a noble metal catalyst section incorporated into the combustion turbine exhaust. The catalyst promotes oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than under normal conditions. The control efficiency is primarily a function of gas residence time and can exceed 90%. For this project, the exhaust gas temperature of 1100°F is in the proper design range. The applicant recognized an oxidation catalyst as the top control. However, the applicant asserts that an oxidation catalyst would result in the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of approximately 2 inches of water column. The lost energy is equivalent to approximately 11,000 mmBTU per year.

Environmental Impacts: The air quality impacts of a DLN system are well below the significant impact levels for CO. There is no additional environmental benefit gained by installing an oxidation catalyst. The air quality impacts of a DLN system alone are well below the PSD significant levels and less than 0.1% of the AAQS.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of an oxidation catalyst would result in capital cost of $1,673,295 per unit. The annualized cost was estimated to be

$561,759 per year. It was assumed that the catalytic system could remove an additional 74 tons of CO per year (90% control efficiency) over a DLN only system at 12 ppmvd @ 15% O_2. This results in a cost effectiveness for the oxidation catalyst of $7595 per ton of CO removed. No such costs would be associated with the efficient combustion of the Model PG7241(FA) gas turbine.

The applicant rejected the oxidation catalyst as not being cost effective and not producing any measurable reductions in air quality impacts. The applicant proposed the following as the best available controls:

Applicant's Proposed CO BACT

Normal Gas Firing Mode: 12.0 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 20.0 ppmvd @ 15% O_2 achieved by water injection

Department's CO BACT Determination

The Department also recognizes an oxidation catalyst as the top control for CO emissions. However, the Department disagrees with many of the applicant's assumptions as summarized below.

Energy Impacts: The Department agrees that installation of an oxidation catalyst *would* result in an energy penalty due to the pressure drop across the catalyst.

Environmental Impacts: The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination.

Economic Impacts: In general, the Department agrees that the addition of an oxidation catalyst would result in a cost effectiveness in the range of $6000 to $8000. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, and energy consumption. Similar to the discussion for NOx controls, the Department recognizes that the cost analysis has been significantly constrained for this project by the applicant's requested operation.

The Department also rejects the addition of an oxidation catalyst as not being cost effective for the project as limited by the applicant's requests. Therefore, the Department establishes the following CO standards as BACT for this project:

CO BACT Determination

Normal Gas Firing: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Gas Firing With Power Augmentation: 15.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Distillate Oil Firing: 20.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by water injection.

Corresponding mass emission limits will also be established for each mode of operation. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. The Department will include the specific conditions identified under NOx controls to ensure that a switch to based loaded units, conversion to combined cycle operation, or substitution with a different make or model of gas turbine will trigger the appropriate permitting actions.

5.3 PARTICULATE MATTER (PM/PM_{10}) AND SULFUR DIOXIDE (SO_2)

Discussion of PM, PM_{10} and SO_2 Emissions

Emissions of particulate matter and sulfur dioxide will result from the combustion of the natural gas and low sulfur distillate fuel. Limited testing indicates that most of the particulate matter emitted from the combustion turbine will be less than 10 microns in diameter (PM_{10}). Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants.

Applicant's Proposed PM, PM_{10}, and SO_2 BACT

The applicant indicated that a review of the EPA RACT/BACT/LAER Clearinghouse did not reveal any post-combustion controls were required for any gas/oil fired combustion turbine projects. Uncontrolled particulate matter emissions are estimated to be less than 0.01 grain per dscf of exhaust gas, which is typically specified as controlled emissions from a baghouse. The use of natural gas as the primary fuel and the restricted use (500 hours per year or less) of very low sulfur (0.05% sulfur by weight or less) distillate oil will result in very low emissions of SO_2.

Applicant's Proposal for PM, PM_{10}, and SO_2 BACT

Each combustion turbine shall be fired primarily with pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF. Low sulfur distillate oil containing no more than 0.05% sulfur by weight shall be fired only as a backup fuel for no more than 500 hours per year.

The applicant indicated that recent BACT determinations for large combustion turbine projects specified such clean fuels as BACT.

Department's PM, PM_{10}, and SO_2 BACT Determination

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. Similarly, there are scrubbers available to further reduce SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas as the primary fuel and to fire a restricted amount of very low sulfur distillate oil as the backup fuel. The Department agrees that further control of particulate matter and sulfur dioxide emissions with one of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case. In addition, a fuel specification for sulfur limits the maximum potential emissions that the gas turbine could emit. The Department establishes the following work practice standards as BACT for PM, PM_{10}, and SO_2.

PM, PM_{10}, and SO_2 BACT

Natural Gas Fuel Specifications: Each combustion turbine shall fire pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF as the primary fuel.

Distillate Oil Fuel Specification: Each combustion turbine shall only fire No. 2 (or superior) distillate oil as a backup fuel containing no more than 0.05% sulfur by weight for no more than 500 hours during any consecutive 12 months.

Also, the Department's definition of BACT in Rule 62-210.200(42), F.A.C. states, "If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit 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." The Department believes that the low particulate matter emission rates from firing the proposed fuels combined with a large diameter stack and very high air flow rates from the gas turbine will lead to non-detectable, or questionable results during performance testing with EPA Method 5. Therefore, the Department will not require initial or annual emissions tests for particulate matter, but will establish the following visible emissions limits as work practice standards that indicate very low levels of particulate matter emissions.

Visible Emissions, Gas Firing: When firing natural gas in any mode of operation, visible emissions from any combustion turbine exhaust shall not exceed 5% opacity.

Visible Emissions, Oil Firing: When firing distillate oil as a backup fuel, visible emissions from any combustion turbine exhaust shall not exceed 10% opacity.

Because the maximum SO_2 emissions are limited by the fuel sulfur specification, the Department sees no benefit in requiring emissions performance tests for SO_2. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur contents. Compliance with the visible emissions standards shall be demonstrated by conducting initial and annual tests in accordance with EPA Method 9.

5.4 PSD SYNTHETIC MINOR LIMITS

Volatile Organic Compounds: VOC emissions result from incomplete combustion when firing natural gas and low sulfur distillate fuel oil. Large combustion turbines such as the Model PG7241(PA) offer high temperatures with very efficient combustion resulting in low levels of volatile organic compounds. Therefore, the Department establishes the following standards as PSD synthetic minor limits for VOC:

Gas Firing, All Modes: 1.5 ppmvw

Oil Firing, Backup Fuel: 3.0 ppmvw

Corresponding mass emission limits will also be established for each mode of operation. These standards limit the potential annual emissions of VOC to less than the Significant Emission Rate of 40 tons per year. Initial compliance with the VOC emissions standard shall be demonstrated by conducting performance tests in accordance with EPA Methods 25 or 25A. EPA Method 18 may be used as an optional method to account for the non-regulated methane fraction of the measured VOC emissions. Compliance shall also be demonstrated during the fiscal year prior to renewing each operation permit.

6.0 OTHER EMISSIONS UNITS

6.1 TWO NATURAL GAS FUEL HEATERS

Each fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas. For continuous operation, total emissions of PM/PM_{10}, SO_2 and VOC are each less than 1 ton per year and emissions of CO and NOx are each less than 10 tons per year. These emissions represent much less than 3% of the total controlled emissions for this project. For these small emissions units, the Department determines that efficient combustion and the firing of natural gas to be BACT.

6.2 OIL STORAGE TANK

A common storage tank (2.1 million gallon) supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbines Nos. 5A and 5B. Because VOC emissions are estimated to be less than 1 ton per year, the Department determines BACT to be the storage of only distillate fuel oil in this tank and compliance with NSPS Subpart Kb which requires the permittee to keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. These records shall be retained for the life of the facility.

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

The following table summarizes the BACT standards determined by the Department for this project. Similar limits will be specified as conditions of the permit.

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
SO_2, PM/PM_{10}	Gas, All Modes	1 grain per 100 SCF of natural gas (PM estimated < 0.003 grains/dscf) Visible emissions ≤ 5% opacity	Fuel records None Base load; initial and annual tests
	Oil	0.05% sulfur by weight distillate oil (PM estimated < 0.003 grains/dscf) Visible emissions ≤ 10% opacity	Fuel records None Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits

Note: The mass emission limits were based on 100% base load, maximum heat input, the fuel higher heating values, compressor inlet conditions of 35° F and 20% RH for normal gas and oil firing, and compressor inlet conditions of 80-95° F and 60% RH for gas firing with power augmentation.

According to the applicant, emissions data from General Electric was, "... *adjusted to reflect degradation when the units operate over time and performance improvements beyond that provided for by the manufacturer's guarantee.*" To account for this overall "degradation", the applicant increased the mass flow rate through the turbine by approximately 11%. This resulted in higher fuel consumption and predicted mass emission rates. However, the Department has reviewed many projects for peaking units as well as projects with power augmentation. The Department believes it is inappropriate to permit emissions increases that result from an applicant's choice to operate under conditions that will significantly degrade the unit such that the manufacturer will no longer guarantee emissions or performance. This was an additional consideration in rejecting the applicant's request for a high temperature "peaking mode" that would result in 70% more NOx emissions than normal gas firing. Therefore, the Department developed mass emission limits based on General Electric's maximum emissions performance estimates, similar limits in recent Department permits for the Model PG7241(FA) gas turbine, and the following conditions:

- For normal gas firing and backup oil firing, mass emission limits were based on operation at base load with a compressor inlet air temperature of 35° F.
- For gas firing with power augmentation, mass emissions limits were based on operation at base load with a compressor inlet air temperature of 95° F for NOx, and a compressor inlet temperature of 80° F for CO (worst-case scenarios).
- Information provided by the applicant did not suggest that the gas turbine would have problems complying with GE's guaranteed CO emissions level of 9 ppmvd @ 15% O_2 for normal gas firing.
- For normal gas firing, General Electric data indicates NOx emissions of 61 lb/hour (9 ppmvd @ 15% O_2) at 35° F. The Department allowed 10 ppmvd @ 15% O_2 with compliance demonstrated by CEMS data on a 3-hour block average as opposed to other Department permits containing long-term 24-hour block averages. The Department believes the slightly higher limit combined with the shorter averaging period better defines peaking operation. To account for the increase, the Department considered the following items in establishing the NOx mass emissions limit: the GE mass emission rate at 59° F is 59 lb/hour; the GE mass emission rate at 35° F is 61 lb/hour; and the mass emission limit for the recent Desoto Power project was 64 lb/hour.

The application indicates that recently issued PSD permits specify emissions limits similar to those requested by the applicant. In support of the Department's BACT determination, the following tables offer a comparison of the Department's emissions limits, the applicant's proposed emission limits, and the emission limits specified for a recent similar project (Desoto Power) consisting of General Electric Model PG7241(FA) gas turbines.

Comparison of FPL Martin With Desoto Power

Emissions Per Unit - Gas/Oil Firing

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	66.99	82.18	86.49
NOx	182.87	207.50	252.10
PM_{10}	17.26	18.70	20.45
SAM	2.54	2.45	4.25
SO_2	33.22	31.78	55.16
VOC	6.21	6.43	11.45

Emissions Per Unit - Gas Only (Including High Power Modes)

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	57.99	78.76	72.04
NOx	115.87	143.91	108.65
PM_{10}	15.26	16.95	16.95
SAM	0.67	0.67	0.66
SO_2	8.72	8.69	8.32
VOC	5.09	5.42	4.66

Comments:

It should be noted that the Desoto Power project allows up to 3390 hours per year of operation with no more than 1000 hours per year of oil firing. The higher emissions are the result of the increased oil firing. In addition, the Desoto Power project also allows up to 12 ppmvd of CO emissions, but did not permit power augmentation.

The gas only case is presented as more typical of actual operations. The Department's draft permit for the proposed FPL Martin project results in approximately 7 tons of NOx per year more than the Desoto Power project. About half of this is the result of limited power augmentation and about half from the slightly higher hourly emission limit. Lower CO emissions are the result of the 9 ppmvd limit established for the FPL Martin project compared to the 12 ppmvd limit specified for the Desoto Power project.

7.2 BACT EXCESS EMISSIONS ALLOWED

1. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. In addition, excess emissions resulting from power augmentation are prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

2. Excess Emissions Allowed: Excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

   (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

   (b) Operation below 50% of base load shall not exceed 120 minutes hours during any calendar day for each combustion turbine.

   (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods. [Design and Rule 62-210.700(1) and (5), F.A.C.]

   (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. However, up to 2 hours of monitoring data during any calendar day may be excluded from the continuous NOx compliance demonstration if excess NOx emissions occur due startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

8.0 RECOMMENDATION AND APPROVAL

The permit project engineer is Jeff Koerner. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer at 850/414-7268 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, P.E., Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

APPENDIX E - EMISSIONS STANDARDS SUMMARY

For informational purposes only, the following table summarizes the emissions standards specified in this permit. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines (5A and 5B)

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg. 10.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg. 12.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr block avg.	Base load; initial and annual tests All loads, certified CEM data
SO_2, PM/PM_{10}	Gas, All Modes	1 grain per 100 SCF of natural gas (PM estimated < 0.003 grains/dscf) Visible emissions ≤ 5% opacity	Fuel records None Base load; initial and annual tests
	Oil	0.05% sulfur by weight distillate oil (PM estimated < 0.003 grains/dscf) Visible emissions ≤ 10% opacity	Fuel records None Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits

Note: The mass emission limits for gas and oil firing were based on 100% base load, maximum heat input, fuel higher heating values, compressor inlet conditions of 35° F and 20% RH for normal firing, and compressor inlet conditions of 80-95° F and 60% RH for gas firing with power augmentation.

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

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

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

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

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

(b) Determination of Prevention of Significant Deterioration (X); and

(c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

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

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

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

APPENDIX GG - NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, Subpart A, General Provisions, including:

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

This emissions unit is subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. The following conditions follow the original NSPS rule language and numbering scheme. Regulations that are not applicable were omitted for clarity. Because this emissions units is subject to an NSPS, it is also subject to the following federal provisions: 40 CFR 60, Subpart A, General Provisions for sources subject to an NSPS, adopted by reference in Rule 62-204.800(7)(d), F.A.C.; 40 CFR 60, Appendix A - Test Methods, Appendix B - Performance Specifications, Appendix C - Determination of Emission Rate Change, Appendix D - Required Emissions Inventory Information, Appendix F - Quality Assurance Procedures, adopted by reference in Rule 62-204.800(7)(e).

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10 million BTU per hour, based on the lower heating value of the fuel fired.

40 CFR 60.331 DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

60.332 STANDARD FOR NITROGEN OXIDES.

(a) On and after the date of the performance test required by Sec. 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b) of this section shall comply with one of the following, except as provided in paragraphs (e) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

Where:

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

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

F = NO emission allowance for fuel-bound nitrogen as defined in the following table:

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (Percent By Weight)	"F" (NOx Percent By Volume)
$N < 0.015$	0
$0.015 < N < 0.1$	0.04(N)
$0.1 < N < 0.25$	0.004 + 0.0067(N – 0.1)
$N > 0.25$	0.005

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

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 100 million Btu per hour based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(f) Stationary gas turbines using water or steam injection for control of NOx emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

On and after the date on which the performance test required to be conducted by Sec. 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

40 CFR 60.334 MONITORING OF OPERATIONS.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within +/- 5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under Sec. 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with Sec. 60.332 by the performance test required in Sec. 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in Sec. 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under Sec. 60.335(a).

(2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) Ice fog. Each period during which an exemption provided in Sec. 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be

reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR 60.335 TEST METHODS AND PROCEDURES.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in Sec. 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Secs. 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(P_r/P_o)^{0.5}\,(e^{19\,(Ho - 0.00633)})\,(288°K/T_a)^{1.53}$$

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

(2) The monitoring device of Sec. 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Sec. 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference--see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some

fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

(e) To meet the requirements of Sec. 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT
FIGURE 1 – QUARTERLY PERFORMANCE SUMMARY REPORT
GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEMS

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NOx TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer and Model No.: ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____________________

Total source operating time in reporting period [a]: ____________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: *On a separate page, describe any changes since last quarter in CMS, process or controls.*

I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Title

____________________ ____________________
Signature *Date*

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 28-Apr-2000 01:09pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Ken Kosky (kkosky@golder.com)

Subject: Gas Turbine Formaldehyde Emissions

Ken,

This is similar to Al's request with regard to MACT for gas turbines. EPA Region 4 has told me they will comment on the Palmetto Power project. One of their concerns is the formaldehyde emissions factor you referenced in the application (Golder, 1998). If you could you provide me the background information for this reference, it would help me in preparing a response.

Thanks. Have a good weekend.

Jeff

Revised version emailed to Rich Piper on 5-11-00 to correct District Office from CD to SED.

JFK

April 28, 2000

Certified Mail - Return Receipt Requested

John M. Lindsay, Plant General Manager
Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: DEP File No. 0850001-008-AC (PSD-FL-286)
FPL Martin Plant
Addition of Two 170 MW Simple Cycle Peaking Combustion Turbines

Dear Mr. Lindsay:

Enclosed is one copy of the draft air construction permit to install two new simple cycle combustion turbines at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Department's Technical Evaluation and Preliminary Determination, Intent to Issue Air Construction Permit, and the Public Notice of Intent to Issue Air Construction Permit are also included.

The Public Notice of Intent to Issue Air Construction Permit must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/jfk

Enclosures

In the Matter of an
Application for Permit by:

John M. Lindsay, Plant General Manager
Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

ARMS Project No. 0850001-008-AC
PSD Permit No. PSD-FL-286
FPL Martin Power Plant
Emission Units 011 – 014
Martin County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of draft permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Florida Power and Light, applied on February 19, 2000 to the Department for an air construction permit to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Draft Permit authorizes the installation of two simple cycle, dual-fuel, General Electric Model PG7241(FA) combustion turbines-electrical generator sets, each having a generating capacity of 170 MW.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ____________ to the person(s) listed:

Mr. John M. Lindsay, FPL*
Mr. Richard G. Piper, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

______________________ (Clerk) ____________ (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

FPL Martin Power Plant
Martin County

Draft Permit No. 0850001-008-AC (PSD-FL-286)
Two New Simple Cycle Combustion Turbines
New Emissions Units 011 - 014

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power and Light (FPL) Company to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The applicant proposes to install of two simple cycle gas turbines, two natural gas fired fuel heaters, and a distillate oil storage tank. Each gas turbine is a General Electric Model PG7241(FA) combustion turbine-electrical generator set with a nominal generating capacity of 170 MW. A determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. Although this project is located at a plant subject to the Power Plant Siting Act, it is not subject to review under Section 403.506, F.S., because it provides for no expansion in steam generating capacity. The applicant's authorized representative is John M. Lindsay, Plant General Manager, for the FPL Martin Power Plant. The applicant's mailing address is P.O. Box 176, Indiantown, FL 34956.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry low-NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for *power augmentation* during peak demand periods, typically summer. The power augmentation mode is restricted to 500 of the allowable hours when firing only natural gas with CO and NOx emissions limited to 15 and 12 ppmvd corrected to 15% oxygen, respectively.

The following table summarizes the project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	Project Potential Annual Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	140	100	Yes	Yes
NOx	374	40	Yes	Yes
PM/PM_{10}	35	15	Yes	Yes

notice to be published in the newspaper

SAM	5	7	No	No
SO_2	67	40	Yes	Yes
VOC	14	40	No	No

An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the

notice to be published in the newspaper

address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue (P.O. Box 15425)
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6755

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

{Note: This document was revised on 05/11/00 to correct the District Office location from the Central District to the Southeast District.}

notice to be published in the newspaper

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

April 28, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. Douglas Neeley, Chief
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: Request for Approval of Custom Fuel Monitoring Schedule
FPL Martin Power Plant
PSD Permit No. PSD-FL-286

Dear Mr. Neeley:

Enclosed is a copy of the Department's draft permit authorizing the installation of two simple cycle, General Electric Model PG7241(FA) combustion turbines with electrical generator sets fired primarily with natural gas. The draft permit also allows up to 500 hours per year of very low sulfur distillate oil as a backup fuel. Each gas turbine is capable of producing a nominal 170 MW of electricity. The existing electric power generating plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. Completion of this project will result in a nominal power production of 2940 MW for the entire plant. The Department's Intent to Issue package was also mailed to Mr. Gregg Worley of Region 4 for comments regarding the BACT determinations.

Please send your written comments on, or approval of, the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% oxygen or a fuel sulfur limit of 0.8% sulfur by weight. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas, which has a maximum SO_2 emission rate of 0.0006 lb/mmBTU (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 1 grain per 100 standard cubic feet (0.003 % sulfur by weight). The requirements have been incorporated into the enclosed draft permit and read as follows:

X. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

(a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan) or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

Y. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

(a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

(c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2), provided:

(1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

(2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

(3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d). [40 CFR 60, Subpart GG; Applicant Request]

Also, please comment on these conditions with respect to the use of the acid rain NOx CEMS for demonstrating compliance as well as reporting excess emissions. Typically NOx emissions will be less than 10 ppmvd corrected to 15% oxygen for gas firing which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedules and these NOx monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Jeff Koerner at 850/414-7268.

Sincerely,

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/jfk

Enclosures

Z 341 355 282

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Doug Neeley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-5-00 0850001-008-AC PSD-F1-286	

PS Form **3800**, April 1995

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Doug Neeley, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 5-4-00

C. Signature
X Bruce Hoke
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

09 1999

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* Z 341 355 282

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief – Bureau of Air Regulation

THROUGH Al Linero, Administrator - New Source Review Section *aaf*

FROM: Jeff Koerner, Project Engineer - New Source Review Section

DATE: April 27, 2000

SUBJECT: FPL Martin Plant
Two Nominal 170 MW Simple Cycle Peaking Combustion Turbines (PSD-FL-286)

Attached is the public notice package to install two new 170 MW simple cycle combustion turbines at FPL's existing power plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. Each unit is a General Electric Model PG7241(FA) gas turbine-electrical generator set capable of producing a nominal 170 MW of electricity. Completion of this project will result in a nominal production capacity of 2940 MW for the existing power plant.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. Each unit will be restricted to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for *power augmentation* during high demand periods, typically summer. Power augmentation (PA) is limited to 500 hours per year and only when firing natural gas. CO and NOx emissions are slightly higher during the power augmentation mode. The draft permit includes the following BACT standards.

<u>CO Emissions</u>: Achieved by the efficient combustion of clean fuels

- Gas Firing, Normal: 9 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
- Gas Firing W/PA: 15 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
- Distillate Oil Firing: 20 ppmvd @ to 15% O_2 based on a 3-hour average, annual test

<u>NOx Emissions</u>: Achieved by dry low-NOx combustion for gas firing and water injection for oil firing

- Gas Firing, Normal: 9 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
  10 ppmvd @ to 15% O_2 based on a 3-hour average, CEMS data
- Gas Firing W/PA: 12 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data
- Distillate Oil Firing: 42 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data

<u>PM/PM_{10} and SO_2 Emissions</u>: Achieved by the efficient combustion of clean fuels

- Firing natural gas as the primary fuel and distillate oil as a backup fuel containing ≤ 0.05% sulfur by weight
- 5% opacity or less when firing natural gas and 10% opacity or less when firing distillate oil, annual test

<u>VOC Emissions</u>: Very low emissions do not trigger a BACT determination for this project

<u>Excess Emissions</u>: Operation below 50% of base load shall not exceed 120 minutes per day. During periods of startup and shutdown, visible emissions are limited to 20% opacity for up to ten, 6-minute observation periods per day. NOx emissions must be recorded during startup, shutdown, and malfunction, but the permittee may exclude two CEMS hourly averages per day due to excess emissions resulting from these conditions.

Day #74 is June 26, 2000. I recommend your approval of the attached Intent to Issue package for this project.

JFK

Attachments

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light – Martin Plant
P.O. Box 176
Indiantown, FL 34956

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911

PROJECT DESCRIPTION

The draft permit authorizes installation of two new 170 MW simple cycle combustion turbines at FPL's existing power plant located in Martin County. Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set capable of producing a nominal 170 MW of electricity. Each peaking unit will be fired primarily with natural gas and restricted to 3390 hours per consecutive 12 months. Of this total, no more than 500 hours may occur when firing low sulfur distillate oil as a backup fuel. The draft permit authorizes steam injection for *power augmentation* (PA) to accommodate summer peaking demands. Operation in the PA mode is limited to 500 hours per year and only when firing natural gas. CO and NOx emissions are slightly higher during the PA mode. Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I Area (Everglades National Park) and Class II areas. The draft permit includes the following BACT standards.

CO emissions will be achieved by the efficient combustion design and shall not exceed: 9 ppmvd @ 15% O_2 for gas firing (test); 15 ppmvd @ 15% O_2 for gas firing w/PA (test); and 20 ppmvd @ 15% O_2 for oil firing (test).

NOx emissions will be achieved by dry low-NOx combustion for gas firing, water injection for oil firing and shall not exceed: 9 ppmvd @ 15% O_2 for gas firing (test); 10 ppmvd @ 15% O_2 for gas firing (CEMS); 12 ppmvd @ 15% O_2 for gas firing w/PA (test and CEMS); and 20 ppmvd @ 15% O_2 for oil firing (test and CEMS).

PM/PM_{10} and SO_2 emissions will be achieved by efficient combustion, the firing of natural gas as the primary fuel and the firing of distillate oil containing less than 0.05% sulfur by weight as a backup fuel. Opacity is limited to 5% or less when firing natural gas and 10% or less when firing distillate oil.

VOC emissions will be minimized by the use of clean fuels and efficient combustion. The inherently low VOC emissions did not trigger a BACT determination for this project.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery F. Koerner
4-27-00

Jeffery F. Koerner, P.E.
Registration Number: 49441

Date

New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection

"More Protection, Less Process"

Printed on recycled paper.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 14-Apr-2000 05:22pm
From: Kosky, Ken
KKosky@GOLDER.com
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)
CC: Alvaro Linero TAL (Alvaro.Linero@dep.state.fl.us)
CC: Rich Piper (Rich_Piper@fpl.com)

Subject: Re: FPL Martin Plant - Peaking Units

Jeff: GE did not supply power augmentation for 59 degrees F, since GE stated that steam power augmentation is only permitted above 59 degrees F. Refer to performance sheet that has the 95 degree ambient temperature for steam power augmentation. However, attached please find a data sheet for steam power augmentation at an ambient temperature of 80 degrees F, at 60% relative humidity with turbine inlet fogging at 95% fogger efficiency. The turbine compressor inlet temperature would be cooled by the fogger by about 9.5 degrees F or very close to a 70 degree F ambient temperature without fogging. Since performance in linear, the 95 degree ambient and 70 degree ambient (80 degree ambient with fogging) would provide the performance characteristics for the machine under steam augmentation.

The modeling was conducted with the margins provided for mass flow with the parameters presented in Tables 2-1 through 2-7 of the PSD attachment in the application. While the margin in mass flow increases flow rate, the modeling was conducted using the range of estimated machine performance and temperatures. Also, the emissions increase proportionally. The conditions modeled were at loads of 50%, 75% and 100% at ambient temperatures of 35 degree F, 59 degree F and 95 degree F. This provides a wide range of estimated turbine performance. The maximum impacts for the project were for oil firing. For SO2 and NOx the maximum impacts were at 75% load and 59 degree F, while for PM and CO the maximum impacts were at 50% load and 95 degree F. All impacts were at least 9 times lower than the Significant Impact Levels. Refer to Table 6-6 in PSD attachment of the application.

Let me know if you need more information. Any assistance in getting a draft permit out ASAP is appreciated.

Regards, Ken

-----Original Message-----
From: Jeff Koerner TAL 850/414-7268 GIC 069
[mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Friday, April 14, 2000 8:12 AM
To: Ken Kosky
Cc: Alvaro Linero TAL; Rich Piper
Subject: FPL Martin Plant - Peaking Units
Sensitivity: Confidential

FPL Martin Plant Gas fuel Steam Power Augmentation with Fogger at 80 degF

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	80.
Fogger Status		On
Fogger Effectiveness	%	95
Output	kW	165,000.
Heat Rate (LHV)	Btu/kWh	9,410.
Heat Cons. (LHV) X 10^6	Btu/h	1,552.7
Auxiliary Power	kW	560
Output Net	kW	164,440.
Heat Rate (LHV) Net	Btu/kWh	9,440.
Exhaust Flow X 10^3	lb/h	3444. → 2286,644 acfm
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	933.1

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	76.
CO	ppmvd	15
CO	lb/h	47.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88
Nitrogen	73.38
Oxygen	12.19
Carbon Dioxide	3.86
Water	9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996

HENRYCO 01/24/2000 17:58 FPL Martin gas BL stm aug 80 fogg.dat

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 10-Apr-2000 03:53pm
From: Kosky, Ken
KKosky@GOLDER.com
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)
CC: rich_piper (rich_piper@fpl.com)
CC: Wood, Janet (jwood@golder.com)

Subject: Re: FPL Martin Plant - Request for Additional Information No. 2

Jeff: Attached is the information requested. I'll send the original out via US mail tomorrow. Please call if you have further questions or you have problems in the files being transmitted. Regards, Ken

-----Original Message-----
From: Jeff Koerner TAL 850/414-7268 GIC 069
[mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Thursday, April 06, 2000 12:17 PM
To: Ken Kosky
Subject: FPL Martin Plant - Request for Additional Information No. 2
Sensitivity: Confidential

April 10, 2000

Jeffery F. Koerner, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

RE: Request for Additional Information
DEP File No. 0850001-001-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Jeff:

This correspondence provides the additional information requested in the Department's April 6, 2000 letter concerning FPL's Martin Peaking Project. The information is provided in the same format as requested.

1. Question: Your response included the GE data sheets for gas firing, but only for a compressor inlet temperature of 75° F. Please provide the GE data sheets for the full range of ambient (inlet) temperatures of 35° F, 59° F, 75° F, and 95° F. Also, a reference was made to recent permits for Fort Myers and Sanford Re-powering projects. It is my understanding that these projects did not require BACT determinations.

Response: Attached please find the GE Data sheets requested. The FPL Fort Myers Repowering Project was not required to under go PSD review and therefore, BACT review was not required. The FPL Sanford Repowering Project was required to under go PSD and BACT review for VOCs.

2. The "high power mode" described in the application represents two separate operating scenarios: steam injection for power augmentation, and elevating the combustion reference temperature just before the gas turbine blades to increase power performance. Combined with the planned peaking operation of these units, the high power modes of operation are expected to increase the designed mass flow rate by 5% due to higher fuel consumption as well as 6% due to overall degradation as a result of this operation. The application reflects this by an 11% increase in the mass flow rate over that specified by General Electric for normal operation. Are these statements accurate?

Response: The "higher power mode" is used to characterize the two modes of operation. One set of performance and emission curves were developed from the GE data to describe an envelope for these "higher power modes". There are slight differences for each mode of operation as can be seen from the GE performance curves. Under steam augmentation, mass flow and heat input increase with concomitant increases in power. Under peak mode, the mass flow remains about the same but the volume flow increases due to higher firing temperature resulting from higher heat input. The 11% increase in mass flow was used as a means for conservatively estimating mass emissions in lb/hr due to the turbine performing better than expected (i.e., higher mass flow for the same heat input) and degradation (i.e., lower heat rate with wear of turbine components potentially allowing higher heat input and mass flow). As mentioned in the previously, the only effect in the analyses presented in the application is that the emissions are conservatively estimated for both the modeling analysis and the BACT evaluation.

3. Question: FPL states that the two proposed combustion turbines for this project are not "Martin 5 and 6" as identified in FPL's "10 Year Power Plant Site Plan" dated April of 1999. Is this correct? The purpose of this question is to notify the applicant that the permit will be conditioned such that modifying the proposed project to incorporate combined cycle operation will trigger a new PSD review as if the project has never been built. In particular, CO and NOx controls must be reevaluated at that point because the constraints that lead to the BACT determinations for these permits will be removed.

Response: The GE Frame 7FA turbines designated for this project are not associated with Martin 5 and 6 as described in FPL's Ten Year Power Plant Site Plan and have an in-service date of 2006 and 2007, respectively. The combustion turbines associated with the Martin Peaking Project are being installed much sooner to increase the reserve margin suggested by the Florida Public Service Commission last fall. It is recognized that if these units are subsequently converted to combined cycle, that PSD including BACT review may be applicable.

4. No additional questions. (No response required.)
5. Question: Your response indicates a revised cost analysis for SCR that was omitted. Please submit.

Response: Attached please find the cost tables. These were inadvertently left out of the letter sent with the Department.

6. Your response indicates a revised cost analysis for an oxidation catalyst that was omitted. Please submit.

Response: Attached please find the cost tables. These were inadvertently left out of the letter sent with the Department.

7. No additional questions regarding the air quality analysis. (No response required.)

Please call if there are any technical questions on the application. Your assistance is always appreciated.

Sincerely,

Kennard F. Kosky, P.E.
Principal
Enclosures
cc: Rich Piper, FPL

Table B-3 rev-1. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$2,835,000	Vendor Estimate
Ammonia Storage Tank	$136,500	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$0	Additional NO_x Monitor and System
Taxes	$0	6% of SCR Associated Equipment and Catalyst
Freight	$141,750	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,180,008	
Direct Installation Costs		
Foundation and supports	$254,401	8% of TDCC;OAQPS Cost Control Manual
Handling & Erection	$445,201	14% of TDCC;OAQPS Cost Control Manual
Electrical	$127,200	4% of TDCC;OAQPS Cost Control Manual
Piping	$63,600	2% of TDCC;OAQPS Cost Control Manual
Insulation for ductwork	$31,800	1% of TDCC;OAQPS Cost Control Manual
Painting	$31,800	1% of TDCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs	$974,002	
Total Capital Costs (TCC)	$4,154,010	Sum of TDCC and TDIC
Indirect Costs		
Engineering	$318,001	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$159,000	5% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$318,001	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Start-up	$63,600	2% of Total Direct Capital Costs; OAQPS Cost Control Manual
Performance Tests	$31,800	1% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contingencies	$95,400	3% of Total Direct Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost	$1,035,802	

Total Direct, Indirect and Capital Costs	$5,189,813	Sum of Capital Costs

Table B-4 rev -1. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$55,220	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$19,690	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$676,028	
Energy Costs		
Electrical	$37,968	80kW/h for SCR & 200kW/h for cooling @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$207,224	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$245,192	
Indirect Annual Costs		
Overhead	$46,049	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$51,898	1% of Total Capital Costs
Insurance	$51,898	1% of Total Capital Costs
Annualized Total Direct Capital	$569,841	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$719,686	
Total Annualized Costs	$1,640,906	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$12,943	NO_x Reduction Only
	$23,932	Net Emission Reduction

Table B-6 rev-1. Direct and Indirect Capital Costs for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$843,000	Vendor Quote
Flue Gas Ductwork	$66,758	Vatavauk,199 0
Instrumentation	$84,300	10% of Associated Equipment
Sales Tax	$0	6% of Associated Equipment/Catalyst
Freight	$42,150	5% of Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$1,036,20 8	
Direct Installation Costs		
Foundation and supports	$82,897	8% of TDCC;OAQPS Cost Control Manual
Handling & Erection	$145,069	14% of TDCC;OAQPS Cost Control Manual
Electrical	$41,448	4% of TDCC;OAQPS Cost Control Manual
Piping	$20,724	2% of TDCC: OAQPS Cost Control Manual
Insulation for ductwork	$10,362	1% of TDCC;OAQPS Cost Control Manual
Painting	$10,362	1% of TDCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$315,862	
Total Capital Costs	$1,352,07 0	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$103,621	10% of TDCC; OAQPS Cost Control Manual
Construction and Field Expense	$51,810	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$103,621	10% of TDCC; OAQPS Cost Control Manual
Start-up	$20,724	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$10,362	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$31,086	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$321,224	
Total Direct, Indirect and Capital Costs (TDICC)	$1,673,29 5	Sum of TCC and TInCC

Table B-7 rev-1. Annualized Cost for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$214,333	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$28,365	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,496	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$257,371	
Energy Costs		
Heat Rate Penalty	$82,890	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu additional fuel costs
Total Energy Costs (TDEC)	$82,890	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,733	1% of Total Capital Costs
Insurance	$16,733	1% of Total Capital Costs
Annualized Total Direct Capital	$183,728	10.98 % Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$221,499	
Total Annualized Costs	$561,759	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$7,595	Simple CycleCombustion Turbine
	$8,496	Net Emission Reduction

FPL Martin Plant **Gas Fuel**

LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,200.	136,700.	91,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,855.	11,820.
Heat Cons. (LHV) X 10^6	Btu/h	1,673.5	1,347.2	1,076.8
Auxiliary Power	kW	560	560	560
Output Net	kW	181,640.	136,140.	90,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,900.	11,890.
Exhaust Flow X 10^3	lb/h	3706.	2979.	2456.
Exhaust Temp.	Deg F.	1095.	1122.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	991.1	831.5	725.6

2,460,599 acfm

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	61.	49.	39.
CO	ppmvd	9.	9.	9.
CO	lb/h	30.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.90	0.90
Nitrogen	75.07	75.10	75.21
Oxygen	12.60	12.67	12.99
Carbon Dioxide	3.88	3.85	3.70
Water	7.56	7.49	7.21

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions

are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:44 FPL Martin gas BL LOAD rge 35

FPL Martin Plant **Gas Fuel**
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	173,000.	129,800.	86,500.
Heat Rate (LHV)	Btu/kWh	9,250.	10,000.	12,050.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.3	1,298.	1,042.3
Auxiliary Power	kW	560	560	560
Output Net	kW	172,440.	129,240.	85,940.
Heat Rate (LHV) Net	Btu/kWh	9,280.	10,040.	12,130.
Exhaust Flow X 10^3	lb/h	3539.	2888.	2396.
Exhaust Temp.	Deg F.	1116.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	951.8	807.5	707.9

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.90	0.90
Nitrogen	74.42	74.46	74.58
Oxygen	12.44	12.57	12.90
Carbon Dioxide	3.87	3.81	3.66
Water	8.39	8.27	7.97

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions

are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:45 FPL Martin gas BL LOAD rge 59

FPL Martin Plant Gas Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	150,300.	112,800.	75,200.
Heat Rate (LHV)	Btu/kWh	9,630.	10,550.	12,770.
Heat Cons. (LHV) X 10^6	Btu/h	1,447.4	1,190.	960.3
Auxiliary Power	kW	560	560	560
Output Net	kW	149,740.	112,240.	74,640.
Heat Rate (LHV) Net	Btu/kWh	9,670.	10,600.	12,870.
Exhaust Flow X 10^3	lb/h	3257.	2694.	2267.
Exhaust Temp.	Deg F.	1143.	1170.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	881.8	761.2	667.1

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	53.	43.	35.
CO	ppmvd	9.	9.	9.
CO	lb/h	26.	22.	18.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.6	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.87	0.87
Nitrogen	73.16	73.20	73.34
Oxygen	12.27	12.41	12.80
Carbon Dioxide	3.78	3.72	3.54
Water	9.92	9.80	9.45

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions

are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:56 FPL Martin gas BL LOAD rge 95

FPL MARTIN PLANT **Distillate Fuel**
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	190,500.	142,900.	95,200.
Heat Rate (LHV)	Btu/kWh	9,945.	10,550.	12,500.
Heat Cons. (LHV) X 10^6	Btu/h	1,894.5	1,507.6	1,190.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	189,110.	141,510.	93,810.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,650.	12,690.
Exhaust Flow X 10^3	lb/h	3862.	3024.	2487.
Exhaust Temp.	Deg F.	1074.	1121.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	1042.6	868.7	752.4
Water Flow	lb/h	130,930.	94,620.	66,770.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	334.	263.	206.
CO	ppmvd	20.	24.	35.
CO	lb/h	68.	65.	77.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	98.0	78.0	61.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	5.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.87
Nitrogen	71.79	72.10	72.73
Oxygen	11.19	11.22	11.76
Carbon Dioxide	5.56	5.60	5.35
Water	10.60	10.23	9.29

SITE CONDITIONS

Elevation	ft.	45.0

Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:00 FPL Martin dis load rge 35

FPL MARTIN PLANT **Distillate Fuel**
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	181,800.	136,400.	90,900.
Heat Rate (LHV)	Btu/kWh	9,960.	10,620.	12,670.
Heat Cons. (LHV) X 10^6	Btu/h	1,810.7	1,448.6	1,151.7
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	180,410.	135,010.	89,510.
Heat Rate (LHV) Net	Btu/kWh	10,040.	10,730.	12,870.
Exhaust Flow X 10^3	lb/h	3683.	2936.	2435.
Exhaust Temp.	Deg F.	1098.	1137.	1182.
Exhaust Heat (LHV) X 10^6	Btu/h	1000.7	841.4	734.9
Water Flow	lb/h	120,720.	86,500.	61,390.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	253.	199.
CO	ppmvd	20.	24.	34.
CO	lb/h	65.	61.	73.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	94.0	75.0	60.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	3.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.88
Nitrogen	71.31	71.72	72.33
Oxygen	11.06	11.21	11.76
Carbon Dioxide	5.56	5.54	5.27
Water	11.21	10.68	9.77

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68

Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:01 FPL Martin dis load rge 59

FPL MARTIN PLANT **Distillate Fuel**
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	160,600.	120,500.	80,300.
Heat Rate (LHV)	Btu/kWh	10,190.	11,010.	13,220.
Heat Cons. (LHV) X 10^6	Btu/h	1,636.5	1,326.7	1,061.6
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	159,210.	119,110.	78,910.
Heat Rate (LHV) Net	Btu/kWh	10,280.	11,140.	13,450.
Exhaust Flow X 10^3	lb/h	3376.	2758.	2323.
Exhaust Temp.	Deg F.	1131.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	926.3	793.5	695.9
Water Flow	lb/h	98,570.	70,300.	49,100.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	289.	232.	183.
CO	ppmvd	20.	24.	36.
CO	lb/h	59.	57.	74.
UHC	ppmvw	7.	7.	7:
UHC	lb/h	13.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	6.5	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	85.0	69.0	55.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	7.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	70.52	70.99	71.61
Oxygen	11.00	11.25	11.86
Carbon Dioxide	5.46	5.38	5.07
Water	12.18	11.54	10.60

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68

Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:03 FPL Martin dis load rge 95

FPL Martin Plant Gas fuel with Steam Power Augmentation
Augmentation only permitted above 59 degF
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE
Ambient Temp.	Deg F.	35.	95.
Ambient Relative Humid.	%	20.0	50.0
Fuel Type		Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835
Fuel Temperature	Deg F	290	290
Output	kW	180,400.	165,100.
Heat Rate (LHV)	Btu/kWh	9,245.	9,265.
Heat Cons. (LHV) X 10^6	Btu/h	1,667.8	1,529.7
Auxiliary Power	kW	560	560
Output Net	kW	179,840.	164,540.
Heat Rate (LHV) Net	Btu/kWh	9,270.	9,300.
Exhaust Flow X 10^3	lb/h	3706.	3372.
Exhaust Temp.	Deg F.	1095.	1130.
Exhaust Heat (LHV) X 10^6	Btu/h	991.6	927.1
Steam Flow	lb/h	0.	110,260.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	12
NOx AS NO2	lb/h	61.	82
CO	ppmvd	9.	15.
CO	lb/h	30.	44.
UHC	ppmvw	7.	7.
UHC	lb/h	15.	14.
VOC	ppmvw	1.4	1.4
VOC	lb/h	3.	2.8
Particulates	lb/h	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.83
Nitrogen	75.07	69.28
Oxygen	12.60	11.20
Carbon Dioxide	3.88	3.80
Water	7.56	14.89

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator

Combustion System	9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/24/2000 17:49 FPL Martin gas BL stm aug 35_95.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	35.
Output	kW	190,300.
Heat Rate (LHV)	Btu/kWh	9,080.
Heat Cons. (LHV) X 10^6	Btu/h	1,727.9
Auxiliary Power	kW	560
Output Net	kW	189,740.
Heat Rate (LHV) Net	Btu/kWh	9,110.
Exhaust Flow X 10^3	lb/h	3713.
Exhaust Temp.	Deg F.	1109.
Exhaust Heat (LHV) X 10^6	Btu/h	1015.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	105.
CO	ppmvd	9.
CO	lb/h	30.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	75.00
Oxygen	12.39
Carbon Dioxide	3.98
Water	7.74

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:49 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	59.
Output	kW	179,500.
Heat Rate (LHV)	Btu/kWh	9,225.
Heat Cons. (LHV) X 10^6	Btu/h	1,655.9
Auxiliary Power	kW	560
Output Net	kW	178,940.
Heat Rate (LHV) Net	Btu/kWh	9,250.
Exhaust Flow X 10^3	lb/h	3541.
Exhaust Temp.	Deg F.	1139.
Exhaust Heat (LHV) X 10^6	Btu/h	983.3

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	101.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	74.34
Oxygen	12.20
Carbon Dioxide	3.98
Water	8.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:46 FPL MARTIN PLANT Peak gas 59 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	95.
Output	kW	156,100.
Heat Rate (LHV)	Btu/kWh	9,595.
Heat Cons. (LHV) X 10^6	Btu/h	1,497.8
Auxiliary Power	kW	560
Output Net	kW	155,540.
Heat Rate (LHV) Net	Btu/kWh	9,630.
Exhaust Flow X 10^3	lb/h	3238.
Exhaust Temp.	Deg F.	1172.
Exhaust Heat (LHV) X 10^6	Btu/h	910.7

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	91.
CO	ppmvd	9.
CO	lb/h	26.
UHC	ppmvw	7.
UHC	lb/h	13.
VOC	ppmvw	1.4
VOC	lb/h	2.6
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88
Nitrogen	73.06
Oxygen	11.99
Carbon Dioxide	3.91
Water	10.16

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 95 dry.dat

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

April 6, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

John M. Lindsay, Plant General Manager
Florida Power and Light – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: Request for Additional Information No. 2
DEP File No. 0850001-008-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Mr. Lindsay:

On March 24, 2000, the Department received a response from Golder Associates to our request for additional information regarding the new project for the FPL Martin Plant. The application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form. The original numbering of the questions has been retained.

1. Your response included the GE data sheets for gas firing, but only for a compressor inlet temperature of 75° F. Please provide the GE data sheets for the full range of ambient (inlet) temperatures of 35° F, 59° F, 75° F, and 95° F. Also, a reference was made to recent permits for Fort Myers and Sanford Re-powering projects. It is my understanding that these projects did not require BACT determinations.

2. The "high power mode" described in the application represents two separate operating scenarios: steam injection for power augmentation, and elevating the combustion reference temperature just before the gas turbine blades to increase power performance. Combined with the planned peaking operation of these units, the high power modes of operation are expected to increase the designed mass flow rate by 5% due to higher fuel consumption as well as 6% due to overall degradation as a result of this operation. The application reflects this by an 11% increase in the mass flow rate over that specified by General Electric for normal operation. Are these statements accurate?

3. FPL states that the two proposed combustion turbines for this project are not "Martin 5 and 6" as identified in FPL's "10 Year Power Plant Site Plan" dated April of 1999. Is this correct? The purpose of this question is to notify the applicant that the permit will be conditioned such that modifying the proposed project to incorporate combined cycle operation will trigger a new PSD review as if the project has never been built. In particular, CO and NOx controls must be reevaluated at that point because the constraints that lead to the BACT determinations for these permits will be removed.

4. No additional questions.

5. Your response indicates a revised cost analysis for SCR that was omitted. Please submit.

6. Your response indicates a revised cost analysis for an oxidation catalyst that was omitted. Please submit.
7. No additional questions regarding the air quality analysis.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Cleve Holladay, meteorologist, at 850/921-8986.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Enclosure

cc: Mr. John M. Lindsay, FPL
Mr. Richard G. Piper, FPL
Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Z 031 391 937

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to John Lindsay	
Street & Number FPL	
Post Office, State, & ZIP Code Martin Plant	
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Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
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0850001-008 AC	
PSD-FI-286	

PS Form **3800**, April 1995

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

John Lindsay, Plant Gen. Mgr
FP&L - Martin Plant
PO Box 176
Indiantown, Fl
34956

A. Received by *(Please Print Clearly)*

B. Date of Delivery 4-10-00

C. Signature

X [signature] ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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☒ Certified Mail ☐ Express Mail
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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* Z 031 391 937

PS Form **3811**, July 1999 Domestic Return Receipt 102595-99-M-1789

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Martin 5

Post-it® Fax Note 7671	Date 4/6/00	# of pages ▶
To Ken Kosky	From	
Co./Dept. Golder Assts.	Co.	
Phone # 352-336-5600	Phone #	
Fax # 352-336-6603	Fax #	

(2)	**Capacity**		
	a. Summer	419 MW	
	b. Winter	448 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2002	
	b. Commercial In-service date:	2006	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	LNB	(Low Nox Burners)
(7)	**Cooling Method:**	CP	(Cooling Pond)
(8)	**Total Site Area:**	11,179	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performnace Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,081	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (In-Service Year $/kW):	590	
	Direct Construction Cost ($/kW):	464	
	AFUDC Amount ($/kW):	54	
	Escalation ($/kW):	72	
	Fixed O&M ($/kW -Yr.):	12.02	(1998$)
	Variable O&M ($/MWH):	0.67	(1998$)
	K Factor:	1.6480	

* Fixed O&M cost includes capital replacement.

From FPL's 10 Year Power Plant Site Plan April 1999

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Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Martin 6		
(2)	**Capacity**		
	a. Summer	419 MW	
	b. Winter	448 MW	
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	LNB	(Low Nox Burners)
(7)	**Cooling Method:**	CP	(Cooling Pond)
(8)	**Total Site Area:**	11,179	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performnace Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,081	Btu/kWh
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	30	years
	Total Installed Cost (In-Service Year $/kW):	604	
	Direct Construction Cost ($/kW):	464	
	AFUDC Amount ($/kW):	55	
	Escalation ($/kW):	84	
	Fixed O&M ($/kW -Yr.):	12.02	(1998$)
	Variable O&M ($/MWH):	0.67	(1998$)
	K Factor:	1.6480	

* Fixed O&M cost includes capital replacement.

Projected Capacity Changes and Reserve Margins for FPL [(1)]					
		Net Capacity Changes (MW)		FPL Reserve Margin	
Year		Summer [(2)]	Winter [(3)]	Summer	Winter
1999	Changes to existing plants	239	80	17%	21%
2000	Changes to existing plants	75	75	15%	19%
2001	Changes to existing plants	20	23	16%	18%
	Changes to existing purchases	(9)	—		
	Ft. Myers Repowering:Initial Phase [(4)]	201	182		
2002	Ft. Myers Repowering:Second Phase	725	920	20%	22%
	Changes to existing plants	—	30		
	Changes to existing purchases	—	(9)		
	Sanford Repowering:Initial Phase [(4),(5)]	202	182		
2003	Sanford Repowering:Second Phase [(5)]	725	919	23%	25%
2004	Changes to existing purchases	(10)	(10)	21%	22%
2005	Changes to existing purchases	—	—	19%	20%
~~2006~~	~~Martin Combined Cycle No.5~~	~~419~~	~~448~~	19%	19%
	Changes to existing purchases	(133)	(133)		
~~2007~~	~~Martin Combined Cycle No.6~~	~~419~~	~~448~~	19%	20%
2008	Unsited Combined Cycle	419	448	20%	20%
	TOTALS=	*3,292*	*3,603*		

Note:

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Summer values are values for August of year shown.

(3) Winter values are values for January of year shown.

(4) The initial phase of the repowering projects consists of the introduction of combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and existing steam turbines.

(5)The values shown above reflect FPL's 1998 IRP which identified that Sanford units #3 and #4 would be repowered. At the time of publication of this document, subsequent to FPL's 1998 IRP, FPL is reexamining its Sanford repowering plan. This reexamination is based on newly developed technical information which focuses on whether it would be more advantageous to repower units #4 and #5 rather than units #3 and #4. Such a change in the Sanford repowering plan would add approximately 240 MW summer capability from the Sanford site beyond what would be gained from repowering units #3 and #4. If such a change is made to the Sanford repowering plan during 1999, it will be communicated to the appropriate state agencies and reflected in FPL's 2000 Site Plan filing.

Table ES.1

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 30-Mar-2000 02:38pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Cleve Holladay TAL (HOLLADAY_C)

Subject: FPL Martin Plant - Combustion Turbine Project

Cleve,

I checked the file for this project. We sent a letter requesting additional information on March 10th. The letter indicated that we did not receive the modeling files until March 3rd and that we would ask those questions within 30 days of March 3rd. Day 30 falls on April 2nd, a Sunday, so I guess you get until Monday, April 3rd. Golder did respond to my questions regarding the equipment on March 24th. Let me know if we need to send out another request for additional information.

Thanks.

Jeff

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

March 23, 2000

9937614A/01

A.A. Linero, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

RECEIVED

MAR 24 2000

BUREAU OF AIR REGULATION

RE: REQUEST FOR ADDITIONAL INFORMATION
DEP FILE NO. 0850001-001-AC (PSD-FL-286)
TWO SIMPLE CYCLE, 170 MW COMBUSTION TURBINES IN MARTIN COUNTY

Dear Al:

This correspondence provides information requested in the Department's March 20 2000 letter concerning FPL's Martin Peaking Project. The information is provided in the same format as requested.

1. Question: The application identifies the General Electric Frame 7FA as the gas turbine model chosen for this project with DLN 2.6 combustors. Please provide manufacturer information supporting the proposed CO and NO_x emissions standards of 10.5 ppmvd and 15 ppmvd, respectively. The Department is aware of other projects that plan to install this model turbine with standards of 9 ppmvd for both CO and NO_x.

Response: Attached are GE data sheets regarding the performance of the simple cycle turbines. These data were used in the development of emissions in Appendix A of the PSD application. A NO_x emission limit of 10.5 ppmvd corrected to 15 percent O_2 is proposed for baseload operation to provide margin due to the peaking nature of the turbines. It is our understanding that the Department has approved similar limits for the simple cycle peaking turbines for Jacksonville Electric Authority and the Tampa Electric Company. In addition, the amount of hours proposed for the Martin project considered the Department's previous determinations. The combination of 10.5 ppmvd corrected to 15 percent O_2 for 2,390 hours of baseload gas fired-operation, 15 ppmvd corrected to 15 percent O_2 for 500 hours of higher power modes (HPM) gas-fired operation and 42 ppmvd corrected to 15 percent O_2 for 500 hours of distillate oil firing, results in lower annual emissions than many previous projects. For example, the proposed limits for the Martin Peaking Project result in 207.5 tons/year of NO_x. In contrast, 9 ppmvd corrected to 15 percent O_2 for 2,390 hours of higher power mode gas-fired operation and 42 ppmvd corrected to 15 percent O_2 for 1,000 hours of distillate oil firing (which has been approved by the Department for previous projects) results in annual potential NO_x emissions of 254 tons/year.

The proposed emission limits for CO are 12 ppmvd for baseload gas-fired operation and 15 ppmvd for HPM. The proposed CO limit for baseload operation is identical to that approved by the Department for the Fort Myers and Sanford Repowering Projects.

2. Question: Please explain the statement on page 2-2 regarding, "... degradation when the units operate over time and performance improvements beyond that provided by the manufacturer's guarantee. In particular, the combustion turbine emission estimates account for 5 percent higher power output and 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine."

Response: The machine performance margin was added since the turbines may perform better than projected. Obviously, the manufacturer must meet minimum performance, which directly relates to mass flow. If the machine performs above the guarantee level, mass flow will increase with a concomitant increase in emissions (at the same concentration). This may also be true as the machine ages and heat rate deteriorates. With a higher heat rate, more fuel and mass flow is needed for the same amount of generation. This margin also provides conservative estimates for modeling purposes. It is recognized that the Department BACT determinations are based on concentrations (i.e., ppmvd corrected to 15 percent O_2 for NO_x and ppmvd for CO).

3. Question: When these units are converted to combined cycle operation as detailed in the "Ten Year Power Plant Site Plan, 1999 – 2008", what additional control equipment does FPL plan to install for the control of CO and NO_x emissions?

Response: The proposed project is planned as a simple cycle project and it is not currently intended that these units be converted to combined cycle. The units referred to in the Ten Year Site Plan are Martin Units 5 and 6, which are combined cycle units identified in the original certification of Martin Unit 3 and 4. If in the future FPL does decide to convert the peaking units to combined cycle, FPL assumes that the BACT determination would need to be revisited for base-loaded (i.e. 8,760 hours) units.

4. Question: According to the manufacturer, how many minutes of startup does it take the unit to reach 50% of base load? How many minutes does it take to shutdown the unit? Please estimate the number of startups in a year based on the proposed maximum 3390 hours per year of operation. The Department plans to address excess emissions from startup and shutdown in the BACT determination.

Response: FPL projects that about 250 starts per unit would be typical for these turbines in peaking service. Unlike combined cycle projects, these peaking turbines can achieve loads greater the 50 percent in about 30 minutes or less. Thus, emission will be minimized and the excess emissions provided in Rule 62-210.700 are sufficient for the operation of these units.

5. Please revise the SCR cost analysis based on the following:

   - Question: Please explain the $50,000 cost for "additional NO_x monitor and system"

   Response: This cost was added for an inlet monitor to better regulate performance of the "hot" SCR system. Without an additional monitor, catalyst degradation would only be known by the amount of ammonia used and NO_x emissions. The effect of this cost was recalculated on the attached revised cost estimates.

- Question: Please explain the 6% tax. Is this Florida sales tax? Does this apply in all cases? Are deductions available for air pollution control equipment?

Response: Sales and other taxes may be applicable to the SCR equipment and were included as a 6 percent charge. The affect of this cost was recalculated on the attached revised cost estimates.

- Question: The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.

Response: See attached revised cost calculations. With this recalculation and those previously noted above, the revised cost effectiveness is $12,943 per ton of NO_x removed. The initial estimate was $13,636 per ton of NO_x removed.

- Question: Please show the calculation for the estimated "tons" of ammonia needed.

Response: Ammonia usage was based on a NO_x removal of 61.1 percent at the maximum potential emissions of 207.5 tons/year and adding 10 percent for ammonia slip. The calculation is: 207.5 tons/year x 0.611 x 17 MW of NH_3 /46 MW of NO_x x 1.10 = 51.5 tons NH_3. This is pure ammonia while the cost estimate is based on aqueous ammonia at 28 percent ammonia in water. The aqueous ammonia usage is 51.54 /0.28 = 184.1 tons/year. Please note that the 10 percent margin on ammonia only account for 4.7 tons/year of ammonia slip, while the vendor guarantee of 9 ppmvd corrected to 15 percent O_2 is 47 tons/year.

- Question: The vendor quote is based on a turbine exhaust flow that includes the 11% "degradation". Doesn't this tend to inflate catalyst costs, ammonia costs, and the overall cost estimate?

Response: As described in response to Question 2, emissions at this level may occur. The effect would have a marginal effect on the annualized cost. Indeed, increasing emissions would directly lower the cost effectiveness since it is inversely proportional. In this case higher emissions would have more of an effect (i.e., increase cost effectiveness by about $1,400 per ton of NO_x removed) than increased costs associated with ammonia (i.e., lower cost effectiveness by less than $100 per ton of NO_x removed).

- Question: On the first page of the Engelhard Corporation vendor quote, the system design basis indicates a similar quote for the Westinghouse Model 501D and the General Electric Model 7FA. It also suggests that the costs were based on an ammonia slip of 9 ppm for the 501D and 5 ppm for the 7FA. Please explain.

Response: The vendor information provided for the Martin Peaking Project in the application was specific for the GE Frame 7FA simple cycle turbine. This was part of information provided by the Engelhard Corporation for various turbine configurations (simple cycle and combined cycle) and manufacturers (both GE and Siemens-Westinghouse) that Golder Associates is currently working.

6. Please revise the oxidation catalyst cost analysis based on the following:

   - Question: What additional "instrumentation" ($84,300) will be added as a result of the oxidation catalyst?

   Response: A continuous emission monitor (CEM) system for CO would be necessary to determine CO emissions from the oxidation catalyst. The Department's previous permits for simple cycle projects have not required CO CEM system.

   - Question: If necessary, revise this cost estimate with regard to the sales tax question in #5.

   Response: Sales and other taxes may be applicable to the SCR equipment and were included as a 6 percent charge. The affect of this cost was recalculated on the attached revised cost estimates.

   - Question: The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.

   Response: See attached revised cost calculations. With this recalculation and those previously noted above, the revised cost effectiveness is $7,595 per ton of NO_x removed. The initial estimate was $7,918 per ton of NO_x removed.

   - Question: The "heat rate penalty" includes a 0.2% MW output loss and a $3/mmBTU of additional fuel costs. Please explain why this wouldn't be considered "double-counting".

   Response: These costs reflect two different and distinct costs that would be incurred by a reduction in power. First, less power would be produced and there would be lost revenue as a result. This cost accounts for 56.4 percent of the heat rate penalty and is based on $40/MWhr at 0.2% of 172.44 MW. Second, the heat rate (Btu/kWhr) is reduced proportionally, which results in proportionally higher fuel costs. This cost is 43.6 percent of the heat rate penalty and is based on gas cost of $3/mmBtu and a heat rate reduction of 0.2% using 1,776 mmBtu/hr.

Please call if there are any technical questions on the application. Your assistance is always appreciated.

Sincerely,

Robert C McCann for

Kennard F. Kosky, P.E.
Principal

KFK/jkw

Enclosures

cc: Rich Piper, FPL

cc: J. Koerner, BAR
R. Piper, FP&L
SED
EPA
NPS
B. Oven, PPS

FPL Martin Plant Steam Power Augmentation on Gas
Guarantee Delta from Baseload Dry
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,835
Fuel Temperature	Deg F	290
Output	kW	178,700.
Heat Rate (LHV)	Btu/kWh	9,060.
Heat Cons. (LHV) X 10^6	Btu/h	1,619.
Auxiliary Power	kW	560
Output Net	kW	178,140.
Delta Output Net	kW	+15,000
Heat Rate (LHV) Net	Btu/kWh	9,090.
Delta Heat Rate (LHV) Net	Btu/kWh	-320
Exhaust Flow X 10^3	lb/h	3538.
Delta Exhaust Flow X 10^3	lb/h	+120.
Exhaust Temp.	Deg F.	1115.
Delta Exhaust Temp.	Deg F.	-13
Exhaust Heat (LHV) X 10^6	Btu/h	968.8
Steam Flow	lb/h	115,670.

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	74.6
CO	ppmvd	15.
CO	lb/h	46.7.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates(TSP)	lb/h	9.0
Particulates(PM10)	lb/h	18.0
Opacity		10%

EXHAUST ANALYSIS

	% VOL.
Argon	0.84
Nitrogen	69.97
Oxygen	11.33
Carbon Dioxide	3.83
Water	14.04

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel. IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 02/18/2000 12:16 FPL Martin gas BL stm aug 75 guar delta.dat

FPL MARTIN PLANT Peak Firing
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	75.
Output	kW	169,500.
Heat Rate (LHV)	Btu/kWh	9,370.
Heat Cons. (LHV) X 10^6	Btu/h	1,588.2
Auxiliary Power	kW	560
Output Net	kW	168,940.
Heat Rate (LHV) Net	Btu/kWh	9,400.
Exhaust Flow X 10^3	lb/h	3413.
Exhaust Temp.	Deg F.	1152.
Exhaust Heat (LHV) X 10^6	Btu/h	952.2

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	97.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates (TSP)	lb/h	9.0
Particulates (PM10)	lb/h	18.0

EXHAUST ANALYSIS	% VOL.
Argon	0.89
Nitrogen	73.80
Oxygen	12.12
Carbon Dioxide	3.95
Water	9.25

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system. Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 75 dry.dat

FPL Martin Plant Gas Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%
Ambient Temp.	Deg F.	75.	75.	75.	75.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290	290
Output	kW	163,700.	122,800.	81,900.	40,900.
Heat Rate (LHV)	Btu/kWh	9,380.	10,190.	12,330.	17,110.
Heat Cons. (LHV) X 10^6	Btu/h	1,535.5	1,251.3	1,009.8	699.8
Auxiliary Power	kW	560	560	560	560
Output Net	kW	163,140.	122,240.	81,340.	40,340.
Heat Rate (LHV) Net	Btu/kWh	9,410.	10,240.	12,410.	17,350.
Exhaust Flow X 10^3	lb/h	3418.	2803.	2336.	2130.
Exhaust Temp.	Deg F.	1128.	1153.	1195.	1028.
Exhaust Heat (LHV) X 10^6	Btu/h	921.1	786.3	692.2	531.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	77.
NOx AS NO2	lb/h	56.	45.	36.	213.
CO	ppmvd	9.	9.	9.	61.
CO	lb/h	28.	23.	19.	119.
UHC	ppmvw	7.	7.	7.	28.
UHC	lb/h	14.	11.	9.	33.
VOC	ppmvw	1.4	1.4	1.4	5.6
VOC	lb/h	2.8	2.2	1.8	6.6
Particulates	lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.88	0.89	0.90
Nitrogen	73.88	73.93	74.04	74.69
Oxygen	12.36	12.49	12.83	14.72
Carbon Dioxide	3.84	3.78	3.62	2.75
Water	9.04	8.92	8.62	6.95

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2.0.1 Opt: 9 72410996
HENRYCO 01/28/2000 17:54 FPL Martin gas BL LOAD rge 75

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG72[illegible](FA)

Load Condition		BASE	75%	50%	25%
Ambient Temp.	Deg F.	75.	75.	75.	75.
Fuel Type		Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78	1.78
Output	kW	173,900.	130,500.	87,000.	43,500.
Heat Rate (LHV)	Btu/kWh	10,020.	10,750.	12,860.	17,360.
Heat Cons. (LHV) X 10^6	Btu/h	1,742.5	1,402.9	1,118.8	755.2
Auxiliary Power	kW	1,390	1,390	1,390	1,390
Output Net	kW	172,510.	129,110.	85,610.	42,110.
Heat Rate (LHV) Net	Btu/kWh	10,100.	10,870.	13,070.	17,930.
Exhaust Flow X 10^3	lb/h	3552.	2871.	2389.	2162.
Exhaust Temp.	Deg F.	1113.	1149.	1193.	1032.
Exhaust Heat (LHV) X 10^6	Btu/h	970.1	823.5	721.0	550.1
Water Flow	lb/h	111,950.	80,050.	56,630.	25,120.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.
NOx AS NO2	lb/h	307.	245.	193.	129.
CO	ppmvd	20.	23.	34.	246.
CO	lb/h	62.	59.	71.	484.
UHC	ppmvw	7.	7.	7.	22.
UHC	lb/h	14.	11.	9.	26.
VOC	ppmvw	3.5	3.5	3.5	11.
VOC	lb/h	7.	5.5	4.5	13.
SO2	ppmvw	11.0	11.0	11.0	8.0
SO2	lb/h	90.0	72.0	58.0	39.0
SO3	ppmvw	1.0	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	8.0	6.0	4.0
Particulates	lb/h	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.86	0.89
Nitrogen	70.94	71.40	72.00	73.93
Oxygen	11.00	11.22	11.77	14.22
Carbon Dioxide	5.54	5.47	5.21	3.88
Water	11.68	11.06	10.17	7.08

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system. Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less. FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value. Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel. IPS- version code- 2 . 0 . 1 Opt: 9. 72410996 HENRYCO 01/28/2000 18:02 FPL Martin dis load rge 75

The Contractor will be allowed to apply offsets on exhaust flow, such that units with greater than guaranteed exhaust flow will offset units with less than guaranteed exhaust flow, in accordance with the following requirements. For a unit to be eligible for the application of offsets, its as-tested minimum exhaust flow shall be equal to or greater than 99 percent of the Exhaust Flow Guarantee. Thus, the maximum offset that can be applied to a unit is one (1) percent of the Exhaust Flow Guarantee. The Contractor will also not be allowed to increase the exhaust flow of a unit that has already tested and met the Exhaust Flow Guarantee in order to increase the level of its offset credit.

C.4 EXHAUST EMISSIONS GUARANTEES. The Contractor guarantees that the following emission values will not be exceeded during the emissions test or any other test conducted in association with measuring the performance of these units. The emission guarantees shall be met during all operation modes from the Minimum Acceptable Emissions Load (50 percent) to the full continuous (base) load capability of each unit for the specified fuels over the full range of specified site ambient conditions.

Emission Parameter	Guarantee Value Gas- Base	Guarantee Value Gas- Power Augmentation	Guarantee Value Distillate- Base
Carbon Monoxide, CO	9 ppmvd	15 ppmvd	20 ppmvd
Nitrogen Oxides, Nox	9 ppmvd @ 15% 0_2	12 ppmvd @ 15% 0_2	42 ppmvd @ 15% 0_2
Volatile Organic Compounds, VOC	1.4 ppmvd		3.5 ppmvd
Particulate (front half of CT only)	9 lb/hr		17 lb/hr
Particulate)front half plus back half of CT)	18 lb/hr		43 lb/hr
Opacity	5%		10%

Stack emissions tests shall be conducted on each combustion turbine unit following the completion of the final combustion turbine generator commissioning tests. The emissions tests may be conducted separately form or concurrently with the performance tests, a the discretion of the Purchaser. The emissions test will be conducted by an independent testing contractor with the assistance of the Contractor, in accordance with mutually agreed upon test procedures to be developed by the Purchaser and the Contractor. The Purchaser will witness the test and will furnish operators, startup power, and fuel. The Regulatory Authority, consisting of local, state, and/or federal agencies, may witness the tests.

The purpose of the emissions test is to demonstrate that the units meet the Contractor's emissions guarantees for all specified fuels. The emissions tests will also serve as compliance test to demonstrate that the units comply with all regulated emissions limits contained in the unit operating permit/air permit. The emissions tests shall be binding on the Contractor to determine compliance with guarantees.

Test instrumentation and methods shall be in accordance with the appropriate US EPA method for each specified pollutant. Measured data and calculated results will be deemed absolute

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 21-Mar-2000 07:43am
From: Alvaro Linero TAL
LINERO_A
Dept: Air Resources Management
Tel No: 850/921-9523

To: Rich_Piper (Rich_Piper@fpl.com)
CC: Jeff Koerner TAL (KOERNER_J)

Subject: Re: Response to Martin RAI

Rich. I would recommend having Bob call Jeff to make sure Bob understands each issues from Jeff's point of view. For example, the manner by which the 10.5 ppmvd is derived needs to be understood and discussed. We have received a number of virtually identical applications (dual fuel simple cycle 7FA units) from Golder with limits of 9 ppmvd with no "allowances" for degradation.

Jeff will get back to you directly. Al.

INTEROFFICE MEMORANDUM

Date: 21-Mar-2000 06:48am
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

Subject: Response to Martin RAI

Al,

We should have a response to you and Jeff Koerner later this week. Please note that Ken Kosky is on vacation, although we've been in touch via email. Due to Ken's absence, if it meets with your approval, we'd like to go ahead and submit our response under Bob McCann's signature. Bob is one of Ken's colleagues at Golder.

- Rich

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

March 10, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

John M. Lindsay, Plant General Manager
Florida Power and Light – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: Request for Additional Information
DEP File No. 0850001-001-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Mr. Lindsay:

On February 19, 2000, the Department received your application with sufficient fee for an air construction permit for two simple cycle, 170 MW combustion turbines to be located at FPL's Martin Plant. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The application identifies the General Electric Frame 7FA as the gas turbine model chosen for this project with DLN 2.6 combustors. Please provide <u>manufacturer</u> information supporting the proposed CO and NOx emissions standards of 10.5 ppmvd and 15 ppmvd, respectively. The Department is aware of other projects that plan to install this model turbine with standards of 9 ppmvd for both CO and NOx.

2. Please explain the statement on page 2-2 regarding, "*... degradation when the units operate over time and performance improvements beyond that provided by the manufacturer's guarantee. In particular, the combustion turbine emission estimates account for 5 percent higher power output and 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine.*"

   Recently, the Department attended a meeting in Cincinnati with General Electric, which included discussions with a representative of the Frame series gas turbine division. GE stated that the current guarantees for the Model 7FA were 9 ppmvd for both CO and NOx. In answer to several questions from the Department, GE could think of no technical reasons why the 7FA could not continue to meet these limits or why intermittent operation would adversely affect emission performance. Please provide supporting information that suggests higher emission rates are necessary, appropriate, or even recommended. The statement in the application seems to indicate that the "high power mode" of operation is outside of the manufacture's recommended performance of the unit and that FPL believes this operation will significantly degrade the units. Please comment.

3. When these units are converted to combined cycle operation as detailed in the "Ten Year Power Plant Site Plan, 1999 – 2008", what additional control equipment does FPL plan to install for the control of CO and NOx emissions? <u>*Note*</u>*: The temperature constraint imposed by simple cycle only*

operation would be relaxed making conventional SCR technically feasible. In addition, combined cycle operation is typically permitted for more than 8000 hours of operation per year, which would tend to make additional controls more cost effective. EPA and the Department have recently determined that conventional SCR systems are commercially available, have been demonstrated down to NOx emission levels of 3.5 ppmvd, and are cost effective.

4. According to the manufacturer, how many minutes of startup does it take the unit to reach 50% of base load? How many minutes does it take to shutdown the unit? Please estimate the number of startups in a year based on the proposed maximum 3390 hours per year of operation. The Department plans to address excess emissions from startup and shutdown in the BACT determination.

5. Please revise the SCR cost analysis based on the following:
   - Please explain the $50,000 cost for "additional NOx monitor and system"
   - Please explain the 6% tax. Is this Florida sales tax? Does this apply in all cases? Are deductions available for air pollution control equipment?
   - The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.
   - Please show the calculation for the estimated "tons" of ammonia needed.
   - The vendor quote is based on a turbine exhaust flow that includes the 11% "degradation". Doesn't this tend to inflate catalyst costs, ammonia costs, and the overall cost estimate?
   - On the first page of the Engelhard Corporation vendor quote, the system design basis indicates a similar quote for the Westinghouse Model 501D and the General Electric Model 7FA. It also suggests that the costs were based on an ammonia slip of 9 ppm for the 501D and 5 ppm for the 7FA. Please explain.

6. Please revise the oxidation catalyst cost analysis based on the following:
   - What additional "instrumentation" ($84,300) will be added as a result of the oxidation catalyst?
   - If necessary, revise this cost estimate with regard to the sales tax question in #5.
   - The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.
   - The "heat rate penalty" includes a 0.2% MW output loss and a $3/mmBTU of additional fuel costs. Please explain why this wouldn't be considered "double-counting".

7. The Department received the modeling input/output files on March 3, 2000. Comments on the air quality impact analysis and additional impacts analysis will follow within thirty days of March 3.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Cleve Holladay, meteorologist, at 850/921-8986.

Sincerely,

3/10

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/jfk

Enclosure

cc: Mr. John M. Lindsay, FPL
Mr. Richard G. Piper, FPL
Ken Kosky, Golder Associates
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

CC: Buck Oven

Z 031 391 879

US Postal Service

Receipt for Certified Mail

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Sent to John Lindsay	
Street & Number FP & L	
Post Office, State, & ZIP Code Indiantown Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 085001-001-AC 3-10-00 PSD-FL-286	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
John Lindsay
FP & L - Martin Plant
PO Box 176
Indiantown, Fl
34956

4a. Article Number
Z 031 391 879

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
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7. Date of Delivery
3 13 00

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X [signature]

8. Addressee's Address *(Only if requested and fee is paid)*

Thank you for using Return Receipt Service.

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 23, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P.O. Box 25287
Denver, CO 80225

Re: FPL Martin Power Plant
Addition of Two New Combustion Turbines
Facility ID No. 0850001-008-AC, PSD-FL 286

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above referenced project. The applicant proposes to install two new General Electric Model 7FA combustion turbines. It is proposed to operate each unit in simple cycle mode for no more than 3390 hours per year. The primary fuel is natural gas with up to 500 hours of oil firing as a backup fuel. The application also requests power augmentation or a "high power mode" with slightly higher emissions.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/414-7268.

Sincerely,

2/22

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/jfk

Enclosures

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 23, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, GA 30303

Re: FPL Martin Power Plant
Addition of Two New Combustion Turbines
Facility ID No. 0850001-008-AC - PSD-FL-286

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above referenced project. The applicant proposes to install two new General Electric Model 7FA combustion turbines. It is proposed to operate each unit in simple cycle mode for no more than 3390 hours per year. The primary fuel is natural gas with up to 500 hours of oil firing as a backup fuel. The application also requests power augmentation or a "high power mode" with slightly higher emissions.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/414-7268.

Sincerely,

2/23

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/jfk

Enclosures

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 22-Feb-2000 09:32pm
From: Alvaro Linero TAL
LINERO_A
Dept: Air Resources Management
Tel No: 850/921-9523

To: Jeff Koerner TAL (KOERNER_J)
CC: Kim Tober TAL (TOBER_K)

Subject: Re: FPL Martin Power Plant - New CTs

Jeff. It should have a brand new PSD number. It is a distinctly different project than whatever is already at Martin. Also log it into ARMS as an AC. I don't care what has been done in the past. See if we can show a correct fee of $0.00 by noting that a fee was paid to the Site Certification Office.

This project will not (repeat will not) go through Governor and Cabinet. Handle as closely as possible to a standard AC. Kim - please do it my way. Don't get any other advice. Just let me know if the system refuses to log the application for lack of a fee. Then we will go from there.

The benefits of being able to monitor the project by ARMS and having public access to the project status via the DEP website greatly outweighs the far-fetched possibility that we will develop a separate module for Site Certification.

Thanks. Al.