FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

November 17, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gary Lambert, Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

Re: DEP File No. 0810194-001-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Dear Mr. Lambert:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the CPV Gulfcoast Power Generating Facility to be located near Piney Point in Manatee County. The Department's Intent to Issue Air Construction Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time 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 questions, please call Teresa Heron at 850/921-9529.

Sincerely,

for C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/th

Enclosures

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1452 9931

Article Sent To:

Mr. Gary Lambert

Postage	$	CPV Gulfcoast,
Certified Fee		Postmark Here
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
Mr. Gary Lambert
Street, Apt. No.; or PO Box No.
45 Bristol Road, Ste 101
City, State, ZIP+4
Easton, MA 02375

PS Form 3800, July 1999 — See Reverse for Instructions

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. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 1-6

C. Signature
X
☐ 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)*
7099 3400 0000 1452 9931

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

In the Matter of an
Application for Permit by:

Mr. Gary Lambert, Executive Vice President
CPV Gulfcoast, Ltd.
45 Bristol Road, Suite 101
Easton, MA 02375

DEP File No. 0810194-001-AC and PSD-FL-300
245 Megawatt Combined Cycle Facility
Manatee 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, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, CPV Gulfcoast, Ltd, applied on September 11, 2000 to the Department to construct nominal 245 megawatt (MW) combined cycle electrical power generating plant consisting of a nominal 170 MW combustion turbine-electrical generator, an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator, a 150-foot stack, a mechancal draft cooling tower, a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. The project will be located at a new site near Piney Point in Manatee County.

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 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.

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.

P.E.

for 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 (including the PUBLIC NOTICE, 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 11/17/00 to the person(s) listed:

Gary Lambert, CPV Gulfcoast, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Chair, Manatee County BCC
Marion Forthoffer, Manatee County EMD
Scott Sumner, P.E.

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 11/17/00
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0810194-001-AC and PSD-FL-300

CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Manatee County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to CPV Gulfcoast Ltd. The permit is to construct nominal 245 megawatt (MW) combined cycle electrical power generating plant near Piney Point in Manatee County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration of Air Quality (PSD), for emissions of particulate matter (PM/PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist, and nitrogen oxides (NO_X). A maximum achievable control technology (MACT) determination for hazardous air pollutants was not required. The applicant's name and address are CPV Gulfcoast Ltd., 45 Bristol Road, Suite 101, Easton, MA 02375.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator; an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NO_x emissions will be controlled by selective catalytic reduction (SCR) to achieve 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, hazardous air pollutants (HAP), and will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions generated due to NO_X control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	102	25/15
Sulfuric acid mist	12	7
SO_2	76	40
NO_x	126	100
VOC	15	40
CO	222	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels for all applicable pollutants. Therefore no increment consumption analysis was required. Emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards. The project has no significant impact on the PSD Class I Chassahowitzka National Wilderness Area.

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 a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments 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.

This project is not subject to Chapter 403, Sections 403.501-518, "Florida Electrical Power Plant Siting Act," because the steam (electrical) generating capacity is less than 75 MW.

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, as well as the rules and statutes which entitle the petitioner to relief; (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.

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:

Dept. of Environmental Protection	Dept. of Environmental Protection	Manatee County Environmental Management Department
Bureau of Air Regulation	Southwest District Office	202 Sixth Avenue, East
111 S. Magnolia Drive, Suite 4	3804 Coconut Drive	Bradenton, Florida 34208
Tallahassee, Florida, 32301	Tampa, Florida 33619-8218	Telephone: 941/742-5980
Telephone: (850)488-1344	Telephone: (813)744-6100	Fax: 941/742-5996
Fax: (850)922-6979	Fax: (813)744-6084	

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 Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Department's technical evaluations and Draft Permit can be viewed at www.dep.state.fl.us/air/permitting.htm by clicking on Utility and Other Facility Permits.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

CPV Gulfcoast, Ltd.

245-Megawatt Combined Cycle Unit

Manatee County

Facility I.D. No. 0810194-001-AC
PSD-FL-300

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

November 17, 2000

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

CPV Gulfcoast, Ltd.
45 Bristol Road, Suite 101
Easton, MA 02375

Authorized Representative: Mr. Gary Lambert, Executive Vice President

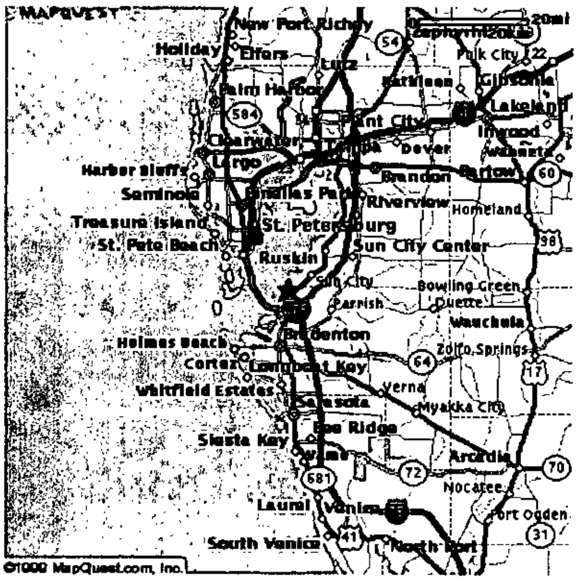
1.2 Reviewing and Process Schedule

09-11-00:	Date of Receipt of Application
10-09-00:	Request for Additional Information (RAI)
11-06-00:	Received CPV Response to Department RAI
11-17-00:	Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figure 1. This new facility will be located on a 160-acre tract at the intersection of Buckeye and Bud Rhoden Roads, southeast of Piney Point in Manatee County. This site is approximately 120 kilometers south of the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates are Zone 17; 348.5 km E; 3057.0 km N.



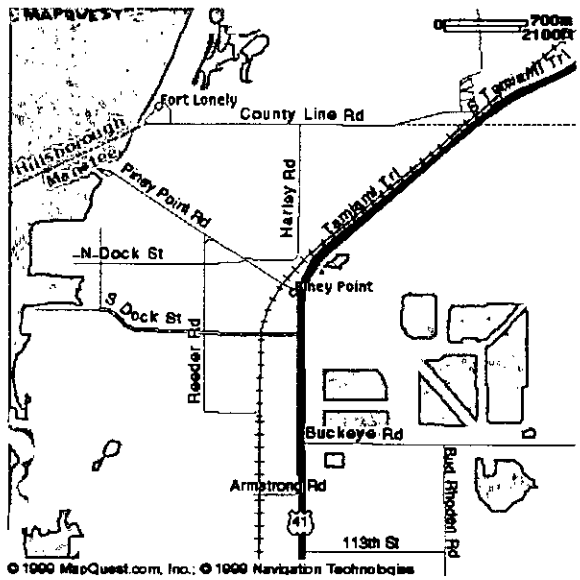


Figure 1 – Location of Piney Point **Figure 2 – Vicinity of Piney Point**

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

This new facility will generate electric power from one nominal 245 MW combined cycle unit including an unfired heat recovery steam generator (HRSG). The combustion turbine will be fired primarily with natural gas as the primary fuel, with distillate fuel as backup.

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY. The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because present emissions are greater than 100 TPY for CO and NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

As a Major Facility, project emissions greater than: Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72 and must apply for an Acid Rain Permit at least 24 months prior to start up.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One 170-megawatt combustion turbine-electrical generator with unfired heat recovery steam generator
002	Water Cooling	Cooling tower
003	Fuel Storage	One 1-million gallon fuel oil storage tank

Competitive Power Ventures (CPV), Gulfcoast Ltd proposes to construct a nominal 245-megawatt (MW) combined cycle combustion turbine at their new site located near Piney Point in Manatee County. The project includes: a nominal 170-MW General Electric 7FA combustion turbine-electrical generator, an un-fired heat recovery steam generator (HRSG) capable of generating sufficient steam to generate another 74.9 MW from a steam-electrical generator, a 150-foot stack, a mechanical draft cooling tower, a 1-million gallon fuel oil storage tank, and other ancillary equipment.

The main fuel will be natural gas and the unit will operate up to 8760 hours per year, of which no more than 720 represent fuel oil operation (30 days). The turbine will have a nominal heat input rating of 1,700 million Btu per hour (mmBtu/hr), lower heating value (LHV), while firing natural gas and 1918 mmBtu/hr, LHV, while firing fuel oil at 25 °F while operating at 100% load.

The turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors and Selective Catalytic Reduction (SCR) to control NO_X emissions to 3.5 parts per million by volume, dry, at 15% O_2 (ppmvd) while burning natural gas and 10 ppmvd while burning fuel oil.

Emission increases will occur for CO, SO_2, sulfuric acid mist (SAM), PM/PM_{10}, VOC, and NO_X.

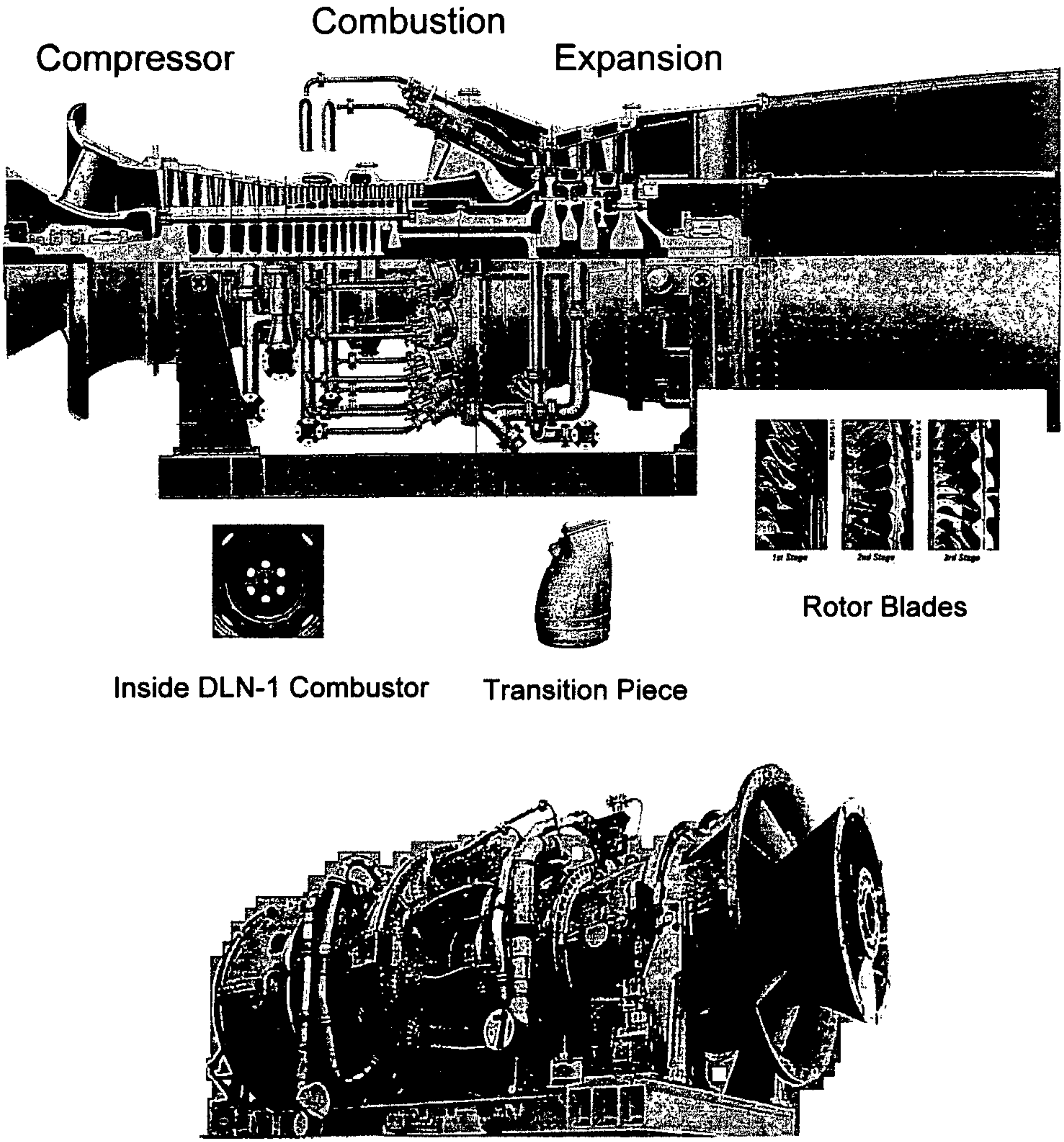


Figure 3 - Internal and External Views of Early GE 7FA

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA (Figure 3) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. Figure 4 is photograph from the GE website of a "7FA on the half-shell" as viewed from the compressor section.

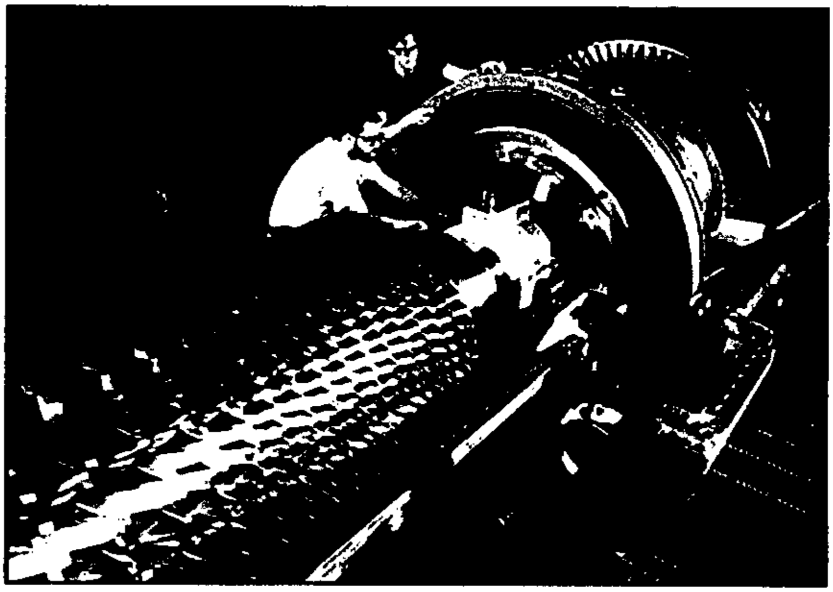


Figure 4 – Internal View of GE 7FA. **(GE Website)**

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower <u>flame</u> temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the CPV project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine, which also drives an electrical generator.

Figure 5 is a process flow diagram for a combined cycle unit basically similar similar to the proposed CPV project. CPV will also include fuel oil back-up, SCR, and power augmentation.

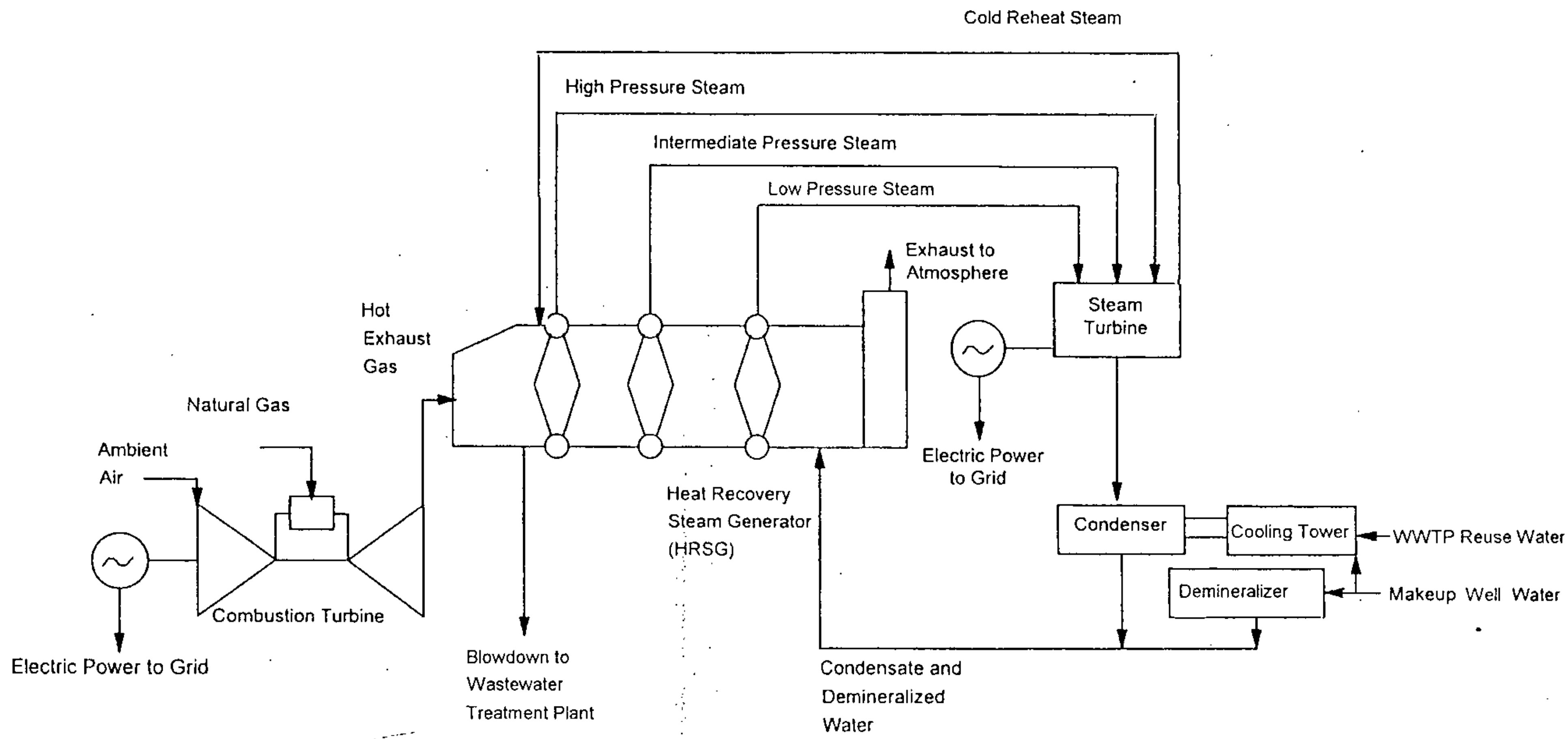


Figure 5 - Process Flow Diagram of a Basic Combined Cycle Power Plant

(gas-only, without SCR, and no power augmentation)

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet air density. To partially compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), a chilling unit or evaporative inlet fogger may be installed ahead of the combustion turbine inlet to increase air density. Neither of these features is planned for the CPV project.

Another possibility is to include a gas-fired duct burner between the combustion turbine and the HRSG. This would raise more steam, however additional steam is not needed because the unit will be easily capable of producing enough steam to drive the undersized steam-electrical turbine.

Other methods of increasing power include power augmentation and peaking. Power augmentation is accomplished by injecting some steam from the HRSG into the rotor (power) section of the combustion turbine. Peaking is simply running the unit at greater than design fuel input.

According to CPV, power augmentation will be employed in this project at temperatures above 59 °F "to make additional electrical output that is lost due to increasing temperature." Power augmentation also provides the opportunity to divert excess steam that cannot be used in the steam cycle (to avoid exceeding 74.9 MW electrical power production by steam-electrical generation). The diversion allows additional power production via the combustion turbine-electrical generator (Brayton Cycle).

The project includes highly automated controls, described as the GE Mark V Control System. The SPEEDTRONIC Mark V Gas Turbine Control System is designed to fulfill all of the gas turbine control requirements.

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Manatee County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, SO_2, SAM and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, SO_2, SAM, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth. This project is exempt from review for Site Certification under the Power Plant Siting Act (Chapter 62-17 F.A.C) because the power (MW) generated from steam is less than the 75 MW threshold..

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subparts GG and Kb
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, sulfuric acid mist, carbon monoxide, and negligible quantities of, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 16 through 21 of Draft Permit PSD-FL-300.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TOTAL TPY) AND PSD APPLICABILITY

Pollutants	Gas Firing[1]	Oil Firing[3]	Total[1]	PSD Significance	PSD REVIEW?
PM/PM_{10}	88	19	102[4]	25	Yes
SO_2	44	36	76	40	Yes
NO_X	106	29	126	40	Yes
CO	197	25	222	100	Yes
Ozone (VOC)	13	3	15	40	No
Sulfuric Acid Mist	8	4	12	7	Yes
Mercury	<<0.1	<<0.1	<0.1	0.1	No
Lead	<<0.6	<<0.6	<0.6	0.6	No
HAPs			8[5]	NA	NA

1. Based on 8760 hours of gas firing. Reference Temperature is 25 °F.
2. Based on 720 hours of fuel oil firing. Reference Temperature is 25 °F
3. Based on 8040 hours of gas firing and 720 hours of fuel oil firing. Reference Temperature is 25 °F.
4. Includes 3.5 TPY of PM/PM10 from the cooling tower.
5. Less than 10 TPY for any single HAP and less than 25 TPY for all HAPs. Case-by-case MACT does not apply.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of inherently clean fuels. During gas operation, the combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The DLN-2.6 combustors will control combustion turbine emissions of CO and NO_X to 9 ppmvd @15% O_2 between 50 and 100% of full load under normal operating conditions and during gas burning. Further control for NO_X will be achieved by SCR to 3.5 (gas) and 10 (oil) ppmvd @15% O_2. Emissions of CO during oil burning are expected not to exceed 20 ppmvd. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, and SAM. PM_{10}, SO_2 and NO_X 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. There are no applicable PSD increments or AAQS for SAM.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS impact and PSD increment analyses for these pollutants were not required. Also, the maximum predicted impacts for all of the pollutants listed above were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project were the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_X;
- 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.

6.4.2 Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. 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 satisfied 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 Tampa, Florida (surface data) and Ruskin, Florida (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.

PSD Class I Area

The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Chassahowitzka National Wilderness Area (CNWA). CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF requires the use of the California Meteorological (CALMET) model for preparation of meteorological data. However, the model can also be used in a screening mode known as CALPUFF Lite. The screening mode utilizes the same meteorological data that is input into the ISCST3 model. As a result, CALPUFF Lite often overestimates impacts and is adequate for use as a screening tool. For this project, the applicant utilized CALPUFF Lite screening mode and the same meteorological data set that was described in the preceding section.

6.4.3 <u>Significant Impact Analysis</u>

Typically, in order to conduct a significant impact analysis, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas. If this modeling at worst load conditions shows significant impacts, additional modeling that includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant does not have to conduct any further modeling.

The significant impact analysis submitted for this project contained two separate analyses; one for the surrounding Class II Area, and another for the CNWA, which is the nearest Class I Area. The following paragraphs explain the results of these two analyses:

PSD Class II Area

Receptors were placed around the proposed facility, which is located in a PSD Class II Area. A combination of fence line, near-field, mid-field, and far-field receptors were utilized for predicting maximum concentrations in the vicinity of the project. The fence line and near field receptors consisted of discrete Cartesian receptors spaced at 50 meter intervals near the facility property boundary. The mid field receptors consisted of discrete Cartesian receptors spaced at 330 meter intervals starting at the end of near field receptor network out to a distance of about 8.3 km from the facility. The remaining receptors consisted of a polar receptor grid with 7 logarithmically spaced rings and 10° spacing radials out to a distance 40 km from the facility. 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. The table below shows the results of the significant impact modeling for the Class II Area:

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	0.02	1	NO
	24-Hour	2.0	5	NO
	3-Hour	10.4	25	NO
PM_{10}	Annual	0.05	1	NO
	24-Hour	1.6	5	NO
CO	8-Hour	7.2	500	NO
	1-Hour	22.8	2000	NO
NO_2	Annual	0.04	1	NO

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project; therefore, no further modeling was required in the surrounding Class II Area.

PSD Class I Area

The Chassahowitzka National Wilderness Area (CNWA) is the closest PSD Class I Area, and is located approximately 109 km north-northwest of the project. The maximum predicted impacts for all applicable pollutants due to the proposed project were compared to the Class I significant impact levels to determine whether there was a significant impact in the CNWA. The table below shows the results of the Class I significant impact modeling:

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (CNWA)

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	0.1	0.2	NO
	3-Hour	0.4	1.0	NO
PM_{10}	Annual	0.004	0.2	NO
	24-Hour	0.05	0.3	NO
NO_2	Annual	0.003	0.1	NO

The results of the significant impact modeling revealed that there were no significant impacts predicted due to the emissions from this project in the CNWA Class I Area. Therefore, no further modeling was not required for this project in the CNWA.

6.4.4 Additional Impacts Analysis

Impact On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 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 also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are 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.

Effects from sulfuric acid mist are expected to be minor. Ammonia emissions will result as a result of NO_X control. The impacts of ammonia on soils, vegetation, and wildlife will be in the same range as the effects of NO_X on the same media.

Nearby fertilizer operations are is a larger source of SO_2 and sulfuric acid mist emissions and use large quantities of ammonia. The impacts from the CPV project on non-air media will be smaller by comparison.

Impact On Visibility

Natural gas is a clean fuel and produces little particulate emissions. The low NO_X and SO_2 emissions will also minimize plume opacity. Due to the large distance between this source and the nearest PSD Class I Area, plus the type and amount of emissions from the source, the U.S. Fish & Wildlife Service believes that there is a low potential for visibility impacts. Therefore, a regional haze analysis was not required for this project.

The effects on visibility due to additional particulate matter from ammonia use are very difficult to quantify. These will be minimized by limiting ammonia emissions (slip) to 5 ppmvd.

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 combustion turbine will require few permanent employees, which will cause no significant impact on the local Area.

This project is a response to state-wide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," and the lowest air emissions per unit of electric power generating capacity.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any maximum achievable control technology (MACT) requirements pursuant to Department rules or Section 112 of the Clean Air Act.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

Teresa Heron, Engineer
A. A. Linero, P.E.
Chris Carlson, Meteorologist

PERMITTEE:

CPV Gulfcoast, Ltd.
45 Bristol Road, Suite 101
Easton, MA 02375

File No.	0810194-001-AC
Permit No.	PSD-FL-300
SIC No.	4911
Expires:	December 30, 2002

Authorized Representative:

Gary Lambert, Executive Vice President

PROJECT AND LOCATION:

Air construction permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD) for the construction of a nominal 245-megawatt (MW) gas-fired combined cycle electrical power plant. The plant will be known as the CPV Gulfcoast Power Generating Facility.

The project will be located at the intersection of Buckeye and Bud Rhoden Roads, East of Highway 41 near Piney Point, Manatee County. UTM coordinates are Zone 17; 348.5 km E; 3057.0 km N.

STATEMENT OF BASIS:

This permit is issued under the provisions of Chapter 403 of the Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code. The above named permittee is authorized to modify the facility 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 of Environmental Protection (Department).

The attached Appendices are made a part of this permit:

Appendix GC	Construction Permit General Conditions
Appendix BD	BACT Determination

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The proposed CPV facility is a nominal 245 MW combined cycle plant. Key components include:

- One nominal 170-MW gas-fired combustion turbine-electrical generator with an un-fired heat recovery steam generator (HRSG) and 150-foot stack;
- A selective catalytic reduction unit located within the HRSG;
- A 1-million gallon storage tank for backup No. 2 distillate fuel oil;
- A steam-electrical generator limited to less than 75 MW;
- A five-cell mechanical draft cooling tower; and
- Ancillary facilities including equipment including buildings, ammonium storage, demineralized water storage, fire water storage, diesel-fired fire water pump, and a 500 kW emergency generator

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One 170-megawatt combustion turbine-electrical generator with unfired heat recovery steam generator
002	Water Cooling	One five-cell mechanical cooling tower
003	Fuel Storage	One 1-million gallon fuel oil storage tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). With respect to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X and SO_2, 25/15 TPY of PM/PM_{10}, 100 TPY of CO, and 7 TPY of sulfuric acid mist. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This Project is not subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is less than 75 MW. [Chapter 403.503 (12), F.S., Definitions]

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- xx/xx/xx Air Construction Permit Issued
- xx/xx/xx Notice of Intent to Issue published in ______________
- 11/17/00 Distributed Intent to Issue Permit
- 11/06/00 Application deemed complete
- 09/11/00 Received PSD Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.

- Application received on September 11, 2000
- Department letter to CPV dated October 9, 2000
- Comments from the Fish and Wildlife Service dated October 6, 2000
- CPV Responses dated November 3, 2000
- Department's Intent to Issue and Public Notice Package dated November 17, 2000.
- Letter from EPA Region IV dated ________________
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II. COMMON SPECIFIC CONDTIONS

GENERAL AND ADMINISTRATIVE 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 (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114.
2. Compliance Authority: All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District Office, 3804 Coconut Palm Dr, Tampa, Fl 33619-8218 and phone number 813/744-6100. Copies of these items shall also be submitted to the Manatee County Environmental Management Department, 202 Sixth Avenue East, Bradenton, Fl 34208, and phone number 813/742-5980.
3. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
4. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
5. Forms and Application Procedures: 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. [Rule 62-210.900, F.A.C.]
6. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
7. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., 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.]
8. PSD Approval to Construct 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)]
9. Permit Expiration Date Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

10. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, the extension of the December 30, 2002 permit expiration date, or any increases in MW generated by steam, heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes; the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.
[40 CFR 52.21(j)(4); 40CFR 51.166(j) and Rule 62-4.070 F.A.C.]

11. Application for Title IV Permit: An application for a Title IV Acid Rain Permit must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

12. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southwest District Office. [Chapter 62-213, F.A.C.]

OPERATIONAL REQUIREMENTS

13. 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.]

14. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

15. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without the applicable air control device operating properly.
[Rule 62-210.650, F.A.C.]

16. Unconfined Particulate Matter 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.]

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. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and conducting the test.
[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.]

22. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

24. Testing procedures: Testing of emissions 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 ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, 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 ambient temperature) and 105 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. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

RECORDS

23. 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

24. Emissions Performance Test Results 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.].

25. Annual Operating Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District Office by March 1st of each year.

26. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (2000 version), shall be submitted to the *Compliance Authority.*

APPLICABLE STANDARDS AND REGULATIONS:

1. Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. Applicable Requirements: Issuance of a permit does not relieve the owner or operator of an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law, notwithstanding that these applicable requirements are not explicitly stated in this permit. In cases where there is an ambiguity or conflict in the specific conditions of this permit with any of the above-mentioned regulations, the more stringent state, federal or local requirement applies.
[Rules 62-204.800; 62-4.070(3), and Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emissions Unit 001. Power Generation, consisting of a nominal 170-megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 002. Fuel Storage, consisting of a 1.0 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.

6. ARMS Emission Unit 003. Five-Cell Mechanical Draft Cooling Tower.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 25°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,700 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,918 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil.

   These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Hours of Operation: The combined cycle power plant may operate 8760 hours per year while firing natural gas. Fuel oil firing is permitted for a maximum of 720 hours per year.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

10. Dry Low NO_X (DLN) combustors shall be installed to reduce NO_X emissions from the combustion turbine exhaust entering the heat recovery steam generator (HRSG).
[Design, Rules 62-4.070 and 62-212.400, F.A.C.]

11. A wet injection system shall be installed for use during fuel oil firing to reduce NO_X emissions from the combustion turbine exhaust entering the HRSG.
[Design, Rules 62-4.070 and 62-212.400, F.A.C.]

12. The permittee shall a selective catalytic reduction (SCR) within the HRSG to comply with the NO_X limits listed in Specific Condition 16.

13. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions Nos. 16 through 21. [Rule 62-4.070, Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

14. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize simple cycle NO_X emissions and CO emissions.
[Rule 62-4.070, and 62-210.650 F.A.C.]

15. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

16. Nitrogen Oxides (NO_X) Emissions:
    - The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas exceed neither 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2) nor 24.1 pounds per hour (lb/hr) on a 3-hr block average. Initial and annual stack test. Continuous compliance shall be determined by a CEMS.
      [Rule 62-212.400, F.A.C., BACT Determination]
    - The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil gas exceed neither 10 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2) nor 80 pounds per hour (lb/hr) on a 3-hr block average. Initial and annual stack test. Continuous compliance shall be determined by a CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
17. Carbon Monoxide (CO) Emissions:
    - Emissions of CO in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 9 ppmvd nor 26 lb/hr on a 3-hr block average during periods when the unit is not operating in the Power Augmentation Mode. Initial and annual stack test as specified in Specific Condition No. 33. Continuous compliance shall be determined by CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
    - Emissions of CO in the stack exhaust gas with the combustion turbine operating on natural gas and in the Power Augmentation Mode shall exceed neither 15 ppmvd nor 49 lb/hr on a 3-hr block average during periods when the unit is operating in the Power Augmentation Mode. Initial and annual stack tests as specified in Specific Condition No. 33. Continuous compliance shall be determined by CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
    - Emissions of CO in the stack exhaust gas with the combustion turbine operating on fuel oil shall not exceed 20 ppmvd nor 70 lb/hr on a 3-hr block average. Initial and annual stack tests as specified in Specific Condition No. 33. Continuous compliance shall be determined by CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
    - The concentration of CO in the stack exhaust gas with the combustion turbine operating on fuel oil shall exceed neither 20 ppmvd at 90-100 percent of full load, 22 ppmvd at 75-89 percent of full load nor 29 ppmvd at 50-74 percent of full load. Continuous compliance shall be determined by CEMS. Initial and annual stack tests as specified in Specific Condition No 33. [Rule 62-212.400, F.A.C, BACT Determination]
18. Volatile Organic Compounds (VOC) Emissions:
    - Emissions of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.4 ppmvw nor 3 lb/hr be demonstrated by initial stack test using EPA Method 25A with correction allowed by deducting methane measured by EPA Method 18. [Rule 62-212.400, F.A.C., BACT]
    - Emissions of VOC in the stack exhaust gas with the combustion turbine operating on fuel oil shall exceed neither 3.6 ppmvw nor 8 lb/hr be demonstrated by initial stack test using

EPA Method 25A with correction allowed by deducting methane measured by EPA Method 18. [Rule 62-212.400, F.A.C., BACT]

19. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist Emissions (SAM):
    - Emissions of SO_2 in the stack exhaust gas exceed neither 10 lb/hr when operating on natural gas nor 99 lb/hr when operating on fuel oil. Compliance shall be demonstrated as specified in Specific Condition No. 31. [Rule 62-212.400, F.A.C., BACT]
    - Emissions of sulfuric acid mist in the stack exhaust gas exceed neither 2 lb/hr when operating on natural gas nor 11 lb/hr when operating on fuel oil. Compliance shall be demonstrated as specified in Specific Condition No. 31. [Rule 62-212.400, F.A.C., BACT]
20. PM/PM_{10} and Visible Emissions (VE):
    - Emissions of PM/PM_{10} in the stack exhaust gas shall exceed neither 20 lb/hr while firing natural gas nor 53 lb/hr while firing fuel oil. Compliance shall be demonstrated by stack tests as specified in Specific Condition No. 31. [Rule 62-212.400, F.A.C., BACT]
    - VE from the stack exhaust gas shall not exceed 10 percent opacity. VE shall serve as the surrogate for compliance with the PM/PM_{10} emission rates following the initial compliance test. Compliance shall be demonstrated by stack tests as specified in Specific Condition No. 36. [Rules 62-204.800(7), 62-4.070, and 62-212.400, F.A.C., BACT]
21. Ammonia Emissions: The concentration of ammonia in the stack exhaust gas shall not exceed 5 ppmvd @15% O_2. The compliance procedures are described in Specific Condition 50. [Rules 62-4.070 and 62-212.400, F.A.C., BACT]

EXCESS EMISSIONS

22. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except for the following modes of operation:
    - *Cold Startup and Shutdown*: During cold *start-up* to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. During *shutdowns* from combined cycle operation, up to three hours of excess emissions are allowed.
    - *Warm Startup and Shutdown*: During warm start up to combined cycle operation, up to two hours of excess emissions are allowed. Warm start-up is defined as a startup to combined cycle operation following a complete shutdown lasting 8 hour or more, but less than 48 hours. During *shutdowns* from combined cycle operation, up to three hours of excess emissions are allowed.
    - *Low Load Operation*: Excluding startup and shutdown, operation below 50% base load is prohibited.

    [G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]

23. Excess Emissions Prohibited: Excess emissions 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and for CO.

24. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify the *Compliance Authority* within one (1) working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one 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. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 16 and 17. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (2000 version)].

COMPLIANCE DETERMINATION

25. Test Compliance Schedule: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of *initial* operation of the unit, and annually thereafter as indicated in this permit or as required by the *Compliance Authority*. [Rule 62-4.070(3) F.A.C and 40CFR60, Subpart A]

26. Initial (I) and Annual (A) Compliance Tests: Initial (I) performance tests (for both fuels) shall be conducted in accordance with 40CFR 60.8 and 40 CFR60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this unit as indicated.
[Rules 62-4.070(3) and 62-204.800, F.A.C., and 40CFR60, Subpart A].

27. Test After Substantial Modifications: All performance tests required for initial start up shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as installation of an oxidation catalyst or change of combustors.

28. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for this combustion turbine to demonstrate compliance with the CO, NO_X, and visible emissions standards for normal gas firing (standard and power augmentation modes), and backup oil firing. 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.]

29. Test Methods: The following reference methods as described in 40 CFR 60, Appendix A (2000 version), and adopted by reference in Chapter 62-204.800, F.A.C. shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5 , "Determination of the Opacity of Emissions from Stationary Sources" (front and back half catch) (I)
    - EPA Reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" (A).
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A) or through annual RATA testing.
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.". Initial tests for compliance with 40CFR60 Subpart GG. Initial and annual test for compliance with the BACT standard.
    - EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
    - EPA Method 26A (modified) for ammonia sample collection (I, A)
    - EPA Draft Method 206 for ion chromatographic analysis for ammonia. (I, Quarterly)

30. Testing Modes of Operation: The permittee shall conduct all required tests for each mode of operation defined below:

    (a) **Standard Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas as well as low sulfur distillate oil.

    (b) **Alternate Mode of Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas and implementing the power augmentation with steam injection. Hourly rates for steam injection for power augmentation (pounds of steam) shall be restricted to the rates that demonstrated compliance during the test for this alternate mode of operation. The maximum steam injection rate (lb steam/hour) for power augmentation shall be established in the operation permit.

    Note: Alternate mode of operation is not allowed when firing low sulfur oil.

    [Rule 62-4.070(3), F.A.C.]

31. Compliance with the SO_2 SAM and PM/PM_{10} Emission Limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas as the primary fuel with a maximum sulfur content of 0.0065 percent by weight and the restricted use (720 hour/year) of No. 2 or superior grade distillate fuel oil with a maximum sulfur content of 0.05 percent sulfur is the method for determining compliance for SO_2 and PM/PM_{10}. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring

Schedule in Specific Conditions 47 and 48 will demonstrate compliance with the NSPS SO_2 emissions limitations from the combustion turbine. Initial PM stack test is required.

[40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

32. Test Method for Natural Gas and Fuel Oil Sulfur Content For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM 2880-71 (or equivalent) for sulfur content of *liquid fuel* and ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of *gaseous fuel* shall be utilized in accordance with the EPA-approved custom fuel monitoring schedules. Natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be submitted when demonstrating compliance with this fuel. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. 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 pursuant to 40 CFR 60.335(e) (2000 version).

33. Compliance with CO Emission Limit: An initial stack test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted. Continuous compliance by CEMS shall be determined as specified in Specific Conditions 41 through 44.

34. Compliance with the NO_X Emission Limit: Compliance with the NO_X limit shall be determined by stack tests and a CEMS as specified in specific conditions Nos. 29, and 41 - 44.

35. Compliance with the VOC Emission Limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required. Initial tests for CO, NO_X, and VOC emissions shall be conducted concurrently.

36. Compliance with the Visible Emission Limit: Initial and annual compliance shall be demonstrated by stack test. VE shall serve as a surrogate for PM/PM_{10} annual compliance test. Initial tests for PM and visible emissions shall be conducted concurrently.

37. Compliance with the Ammonia Emissions: The permittee shall calculate and report the ppmvd ammonia slip @ 15% O_2 at the measured lb/hr emission rate as a means of compliance with the BACT standard. The permittee shall also be capable of calculating ammonia slip according to Specific Condition 50.

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by CPV shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

39. Compliance Test Reports: 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), F.A.C.

40. NSPS Notifications: All notifications and reports required by the 40CFR 60, Subpart A applicable requirements shall be submitted to the Department's District Office and to the Manatee County Environmental Management Department.

MONITORING REQUIREMENTS

41. Required Continuous Monitoring System for NO_X and CO: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen (NO_X) and carbon monoxide (CO) from this unit. Each device shall properly function prior to the initial performance tests and comply with the applicable monitoring system requirements of 40 CFR 75.62. Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 62-4.130, F.A.C and 40CFR75]

42. Continuous Monitoring System Certification and Quality Assurance Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Continuous Monitoring System Operation: The continuous monitoring systems (CEMS) for NO_X and CO shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as require in Specific Conditions 24 and 45. [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 60.13, 40 CFR 75]

44. Continuous Compliance with the CO and NO_X Emission Limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated with the CEM system on a 3-hr average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hr period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 3-hr period. A valid hourly emission rate shall be calculated for each hour in which at least two measurements are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 24 and 45. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

45. CEMS for Reporting Excess Emissions: The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (2000 version). Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15 % oxygen) and CO emissions are above the permit limits listed in Specific Conditions 16 and 17, shall be reported to the *Compliance Authority* as required in Specific Condition 24.

46. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (2000 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (2000 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. [EPA approval dated February 10, 1999]

47. Natural Gas Monitoring Schedule: 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 the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline-supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- 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 a 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).

48. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

49. Selective Catalytic Reduction (SCR) System

The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by the manufacturer's guidelines and in accordance with this permit. During turbine start-up, permittee shall begin use of SCR (i.e., commence ammonia injection) as soon as possible and within two (2) hours of the initial turbine firing or when the temperature of the catalyst bed reaches a suitable predetermined temperature level, whichever occurs first. During turbine shutdown, permittee shall discontinue use of the SCR (i.e., discontinue ammonia injection) when the catalyst bed temperature drops below the predetermined temperature levels, but no more than one hour prior to the time at which the fuel feed to the turbine is discontinued. Suitable temperature for activation and deactivation of the SCR shall be established during performance testing. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit while minimizing ammonia slip to below the emission limit.

50. Ammonia Stack Tests and Injection

- An initial and quarterly stack emission test for ammonia shall be conducted for natural gas and fuel oil firing. The initial and annual (one of the four quarters) NO_X and ammonia stack tests shall be conducted at four points within the operating range of the combustion turbine. The ammonia injection rate necessary to comply with the NO_X standard for each test load, shall be established.
- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. It shall be maintained and calibrated according to the manufacturer's specifications.

51. Continuous Compliance with the 74.9 MW Steam Power Generated Limitation:

Electrical power from the steam-electrical generator shall be limited to 74.9 MW on an hourly basis. CPV shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system.

Exceedance of this limit is not allowed and can result in a requirement to obtain plant certification under Sections 403.501-518, F.S.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

CPV Gulfcoast Power Generating Facility
PSD-FL-300 and 0810194-001-AC
Manatee County, Florida

BACKGROUND

The applicant, CPV Gulfcoast, Ltd, proposes to install a construct a nominal 245-megawatt (MW) (net) combined cycle power plant at a new facility near Piney Point, Manatee County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 170 MW, General Electric 7FA combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) connected to a steam turbine-electrical generator to produce an additional 74.9 MW of electrical power. The project also includes a 1 million gallon storage tank for backup No. 2 fuel oil, cooling tower, a 150-foot stack, and a mechanical draft cooling tower and other ancillary equipment. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated November 17, 2000, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on September 11, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, TRC.

REVIEW GROUP MEMBERS:

Teresa Heron, Permit Engineer and A. A. Linero, P.E.

BACT REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	3.5 ppmvd @15% O_2 (gas) 10 ppmvd@15% O_2 (oil)
Carbon Monoxide	Combustion Controls	.9 ppmvd (gas) 20 ppmvd (oil)
Particulate Matter	Inherently Clean Fuels Combustion Controls	20 lb/hr (gas) 53 lb/hr (oil)
Sulfur Dioxide/Sulfuric Acid Mist	Low Sulfur Fuels	0.0065% sulfur (gas) 0.05% sulfur (oil)

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, 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 stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the CPV is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency unit to be purchased by CPV. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

There is a National Emission Standard for Hazardous Air Pollutants (NESHAP) under development by EPA, but it is not applicable to this project. Because emissions of HAP are less than 10 tons per year, there is no requirement to conduct a case-by-case maximum achievable control technology determinaion.

DETERMINATIONS BY STATES:

The following table is a sample of information on some recent applications, proposals, and determinations in the Southeast for combined cycle projects. The CPV Gulfcoast Project is included for reference.

TABLE 1

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Capacity Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
CPV Gulfcoast. FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT Under Review
TECO Bayside, FL	1750	3.5 – NG 16.4 - FO	SCR	7x170 MW GE 7FA CTs Repowering Review. Possibly $SCONO_X$ on 1 CT
FPC Hines II, FL		3.5 - NG 15 - FO	SCR	2x170 MW WH501F Under Review
Calpine Osprey, FL	527	3.5 – NG		2x170 MW WH501F Draft 5/00
Santee Cooper, SC	~500	9 – NG	DLN	2x170 MW GE 7FA CTs ~ 4/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG (12 – simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
Lake Worth LLC. FL	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
CT = Combustion Turbine

TABLE 2

RECENT CO, VOC, AND PM NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppmv (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
CPV Gulfcoast, FL	9 - NG (50 - 100% load)) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	20 lb/hr – NG 51 lb/hr – FO 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	7.2 – NG 14.2 - FO	1.2 – NG 2.8 FO	20 lb/hr – NG 53 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	10 - NG (100% load)) 50 - NG (60% load) 30 – FO (100% load)	1.8 - NG (100% load)) 3 – NG (60% load) 10 – FO (100% load)	10% Opacity – NG 20% Opacity - FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Alabama Power Theo	~36 – CT & DB	~12.5 CT & DB		Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion

All of the projects listed above control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. In every case, pipeline quality natural gas is used and has a sulfur content less than 2 grains per 100 cubic. In some cases, the limits are even lower or are expressed in different terms. However all ultimately rely on a fairly uniform gas distribution network and have very little flexibility in actually controlling sulfur content. Similarly, emissions of these two pollutants are controlled by using 0.05 percent sulfur distillate fuel oil.

Some of the projects listed above include front and back half catch for PM limits. Therefore comparison is not simple.

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Comments from the National Park Service dated September 27, 2000
- Comments from from EPA Region IV dated ______________
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. *Thermal NO_X* forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. *Prompt NO_X* is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 1 which is from a General Electric discussion on these principles.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is limited to no more than 30 days or 720 hours per year.

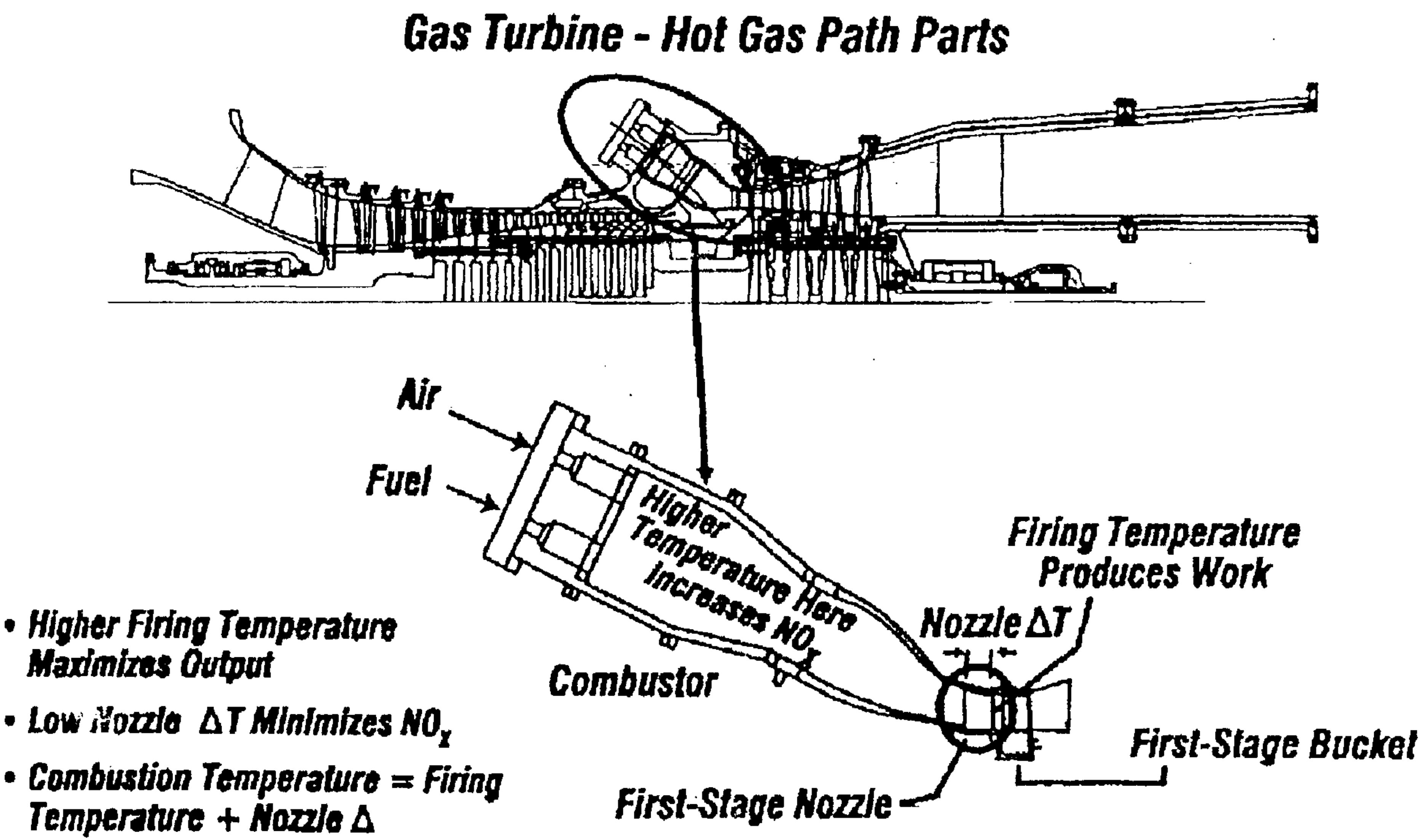


Figure 1 – Relation Between Flame Temperature and Firing Temperature

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for the turbine of the CPV Gulfcoast Project. The proposed NO_X controls will significantly reduce these emissions.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN)

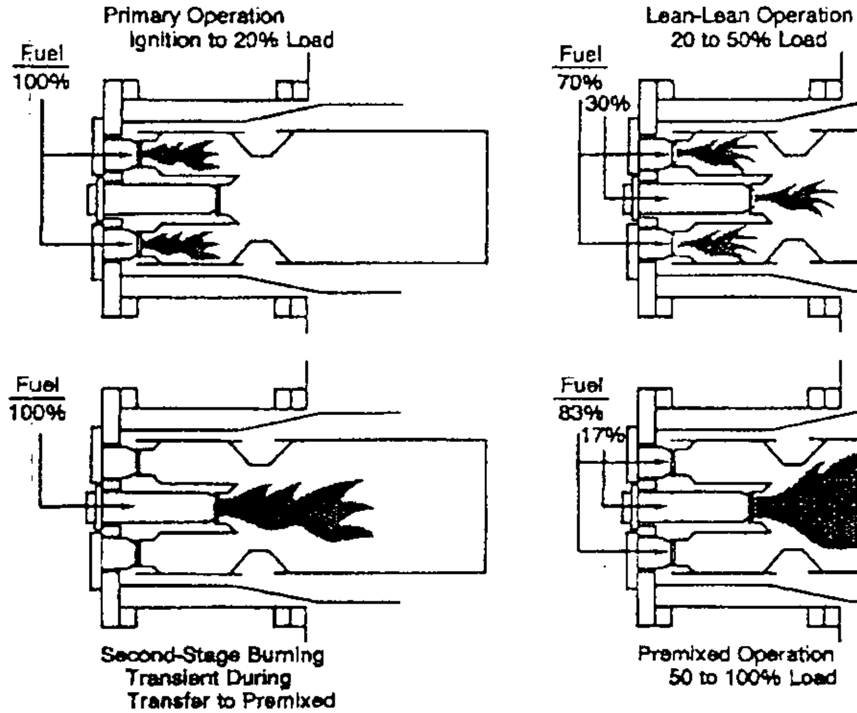
The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 2 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 2) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the CPV Gulfcoast project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.



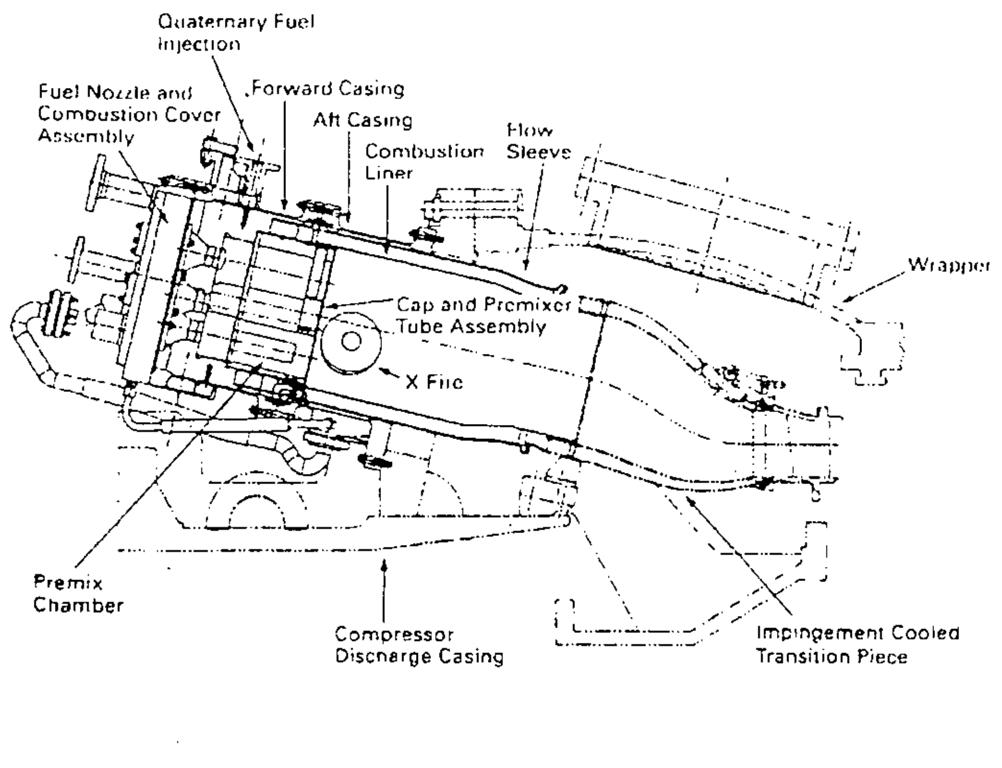


Figure 2 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

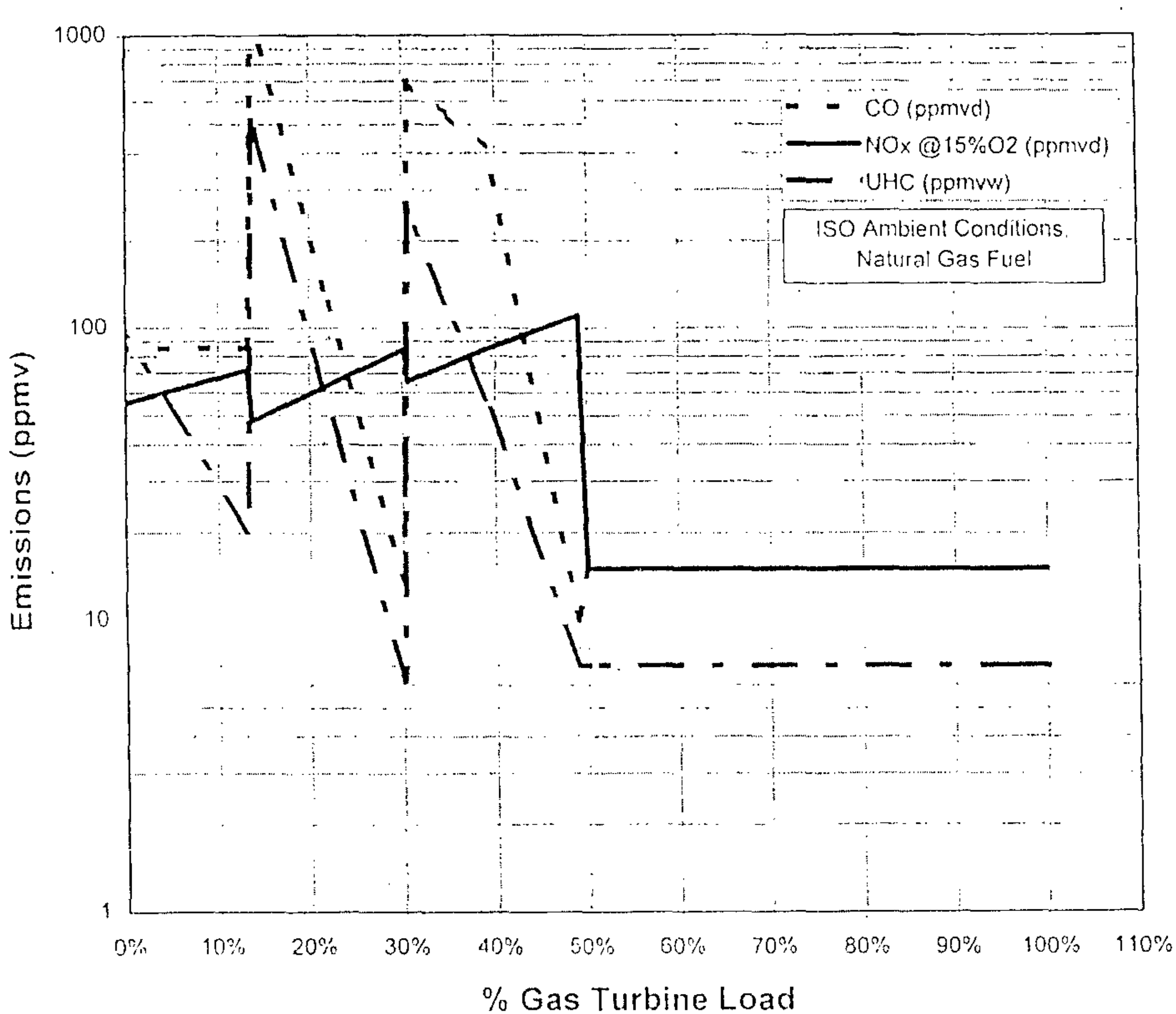


Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_x)

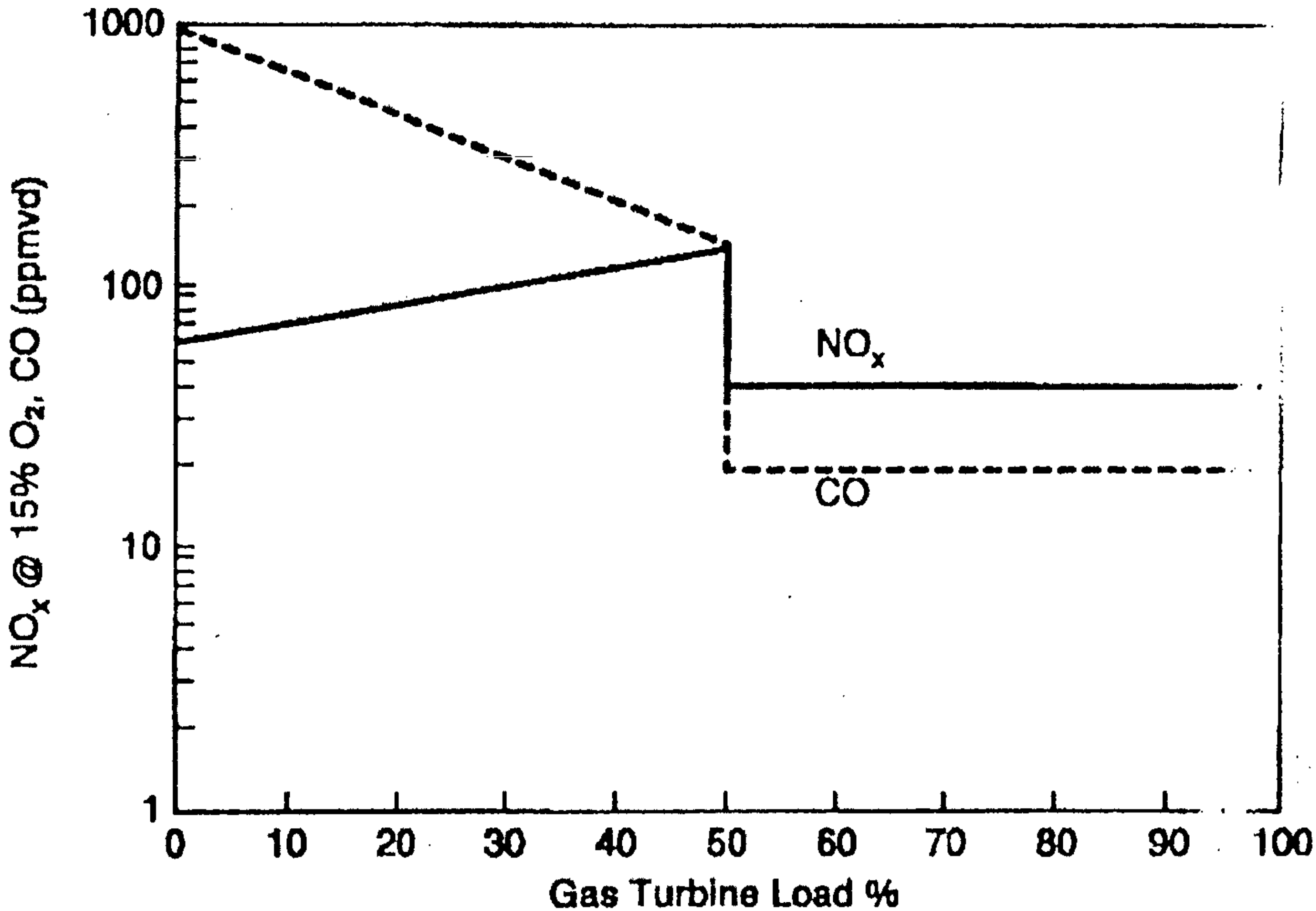


Figure 4 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

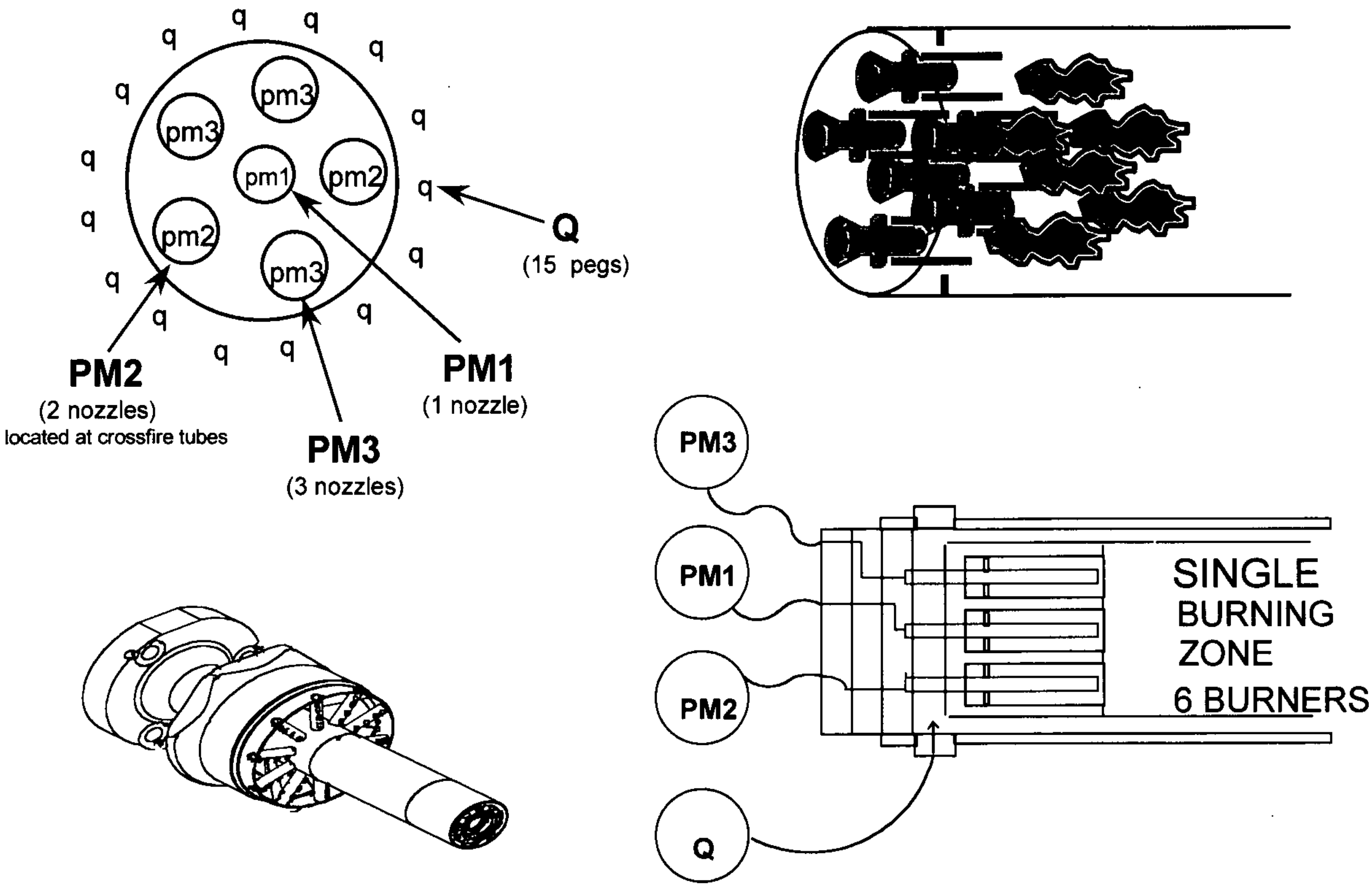


Figure 5 - DLN2.6 Fuel Nozzle Arrangement

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppmvd of CO. Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 4. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the CPV Gulfcoast project are shown in Figure 5.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 6 from an EPRI report.[1] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 6.

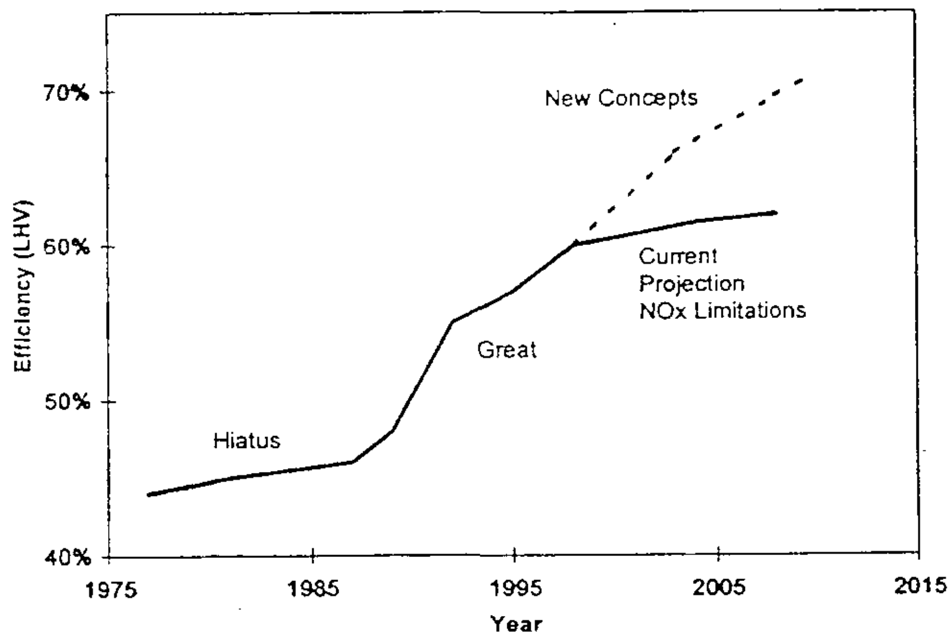


Figure 6 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (Westinghouse G or General Electric H Class technology) than the units planned by CPV. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[2], but the Department does not know their performance on fuel oil. Mitsubishi (who also make a 501F) is also developing a dual-fuel DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[3] The details are not available in English.

Catalytic Combustion: XONON ™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described in the DLN technology above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[4] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents. Westinghouse is working to replace the central pilot in its DLN technology with a catalytic pilot in a project with Precision Combustion Inc.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[5] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Recently, Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[6] The project will enter commercial operation by the summer of 2001. However actual installation of XONON on the Pastoria project is doubtful.

In principle, XONON™ will work on a simple cycle project. However, the Department does not have information regarding the status of the technology for fuel oil firing and cycling operations.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority (KUA) will install SCR at the Cane Island Unit 3 project as a result of insistence by EPA that DLN technology to achieve 9 ppmvd of NO_X was not BACT. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Since then, the Department has consistently advised prospective applicants that BACT is 3.5 ppmvd. Accordingly, FPC submitted an application for the Hines Power Block II project with a BACT NO_X proposal of 3.5 ppmvd by SCR. CPV proposes the same for the present project by SCR. TECO proposes the same limit by SCR for its Bayside Repowering Project.

Figure 7 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 8 is a photograph of FPC Hines Energy Complex. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

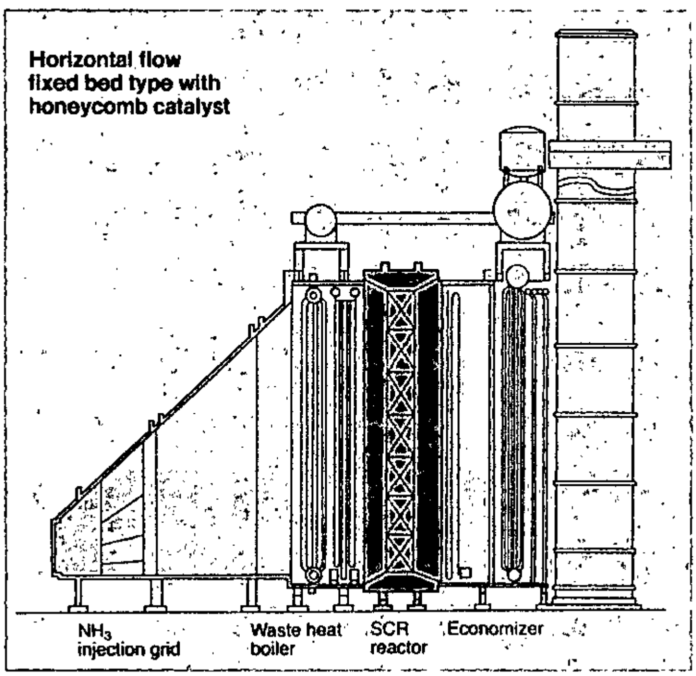


Figure 7 – SCR System within HRSG

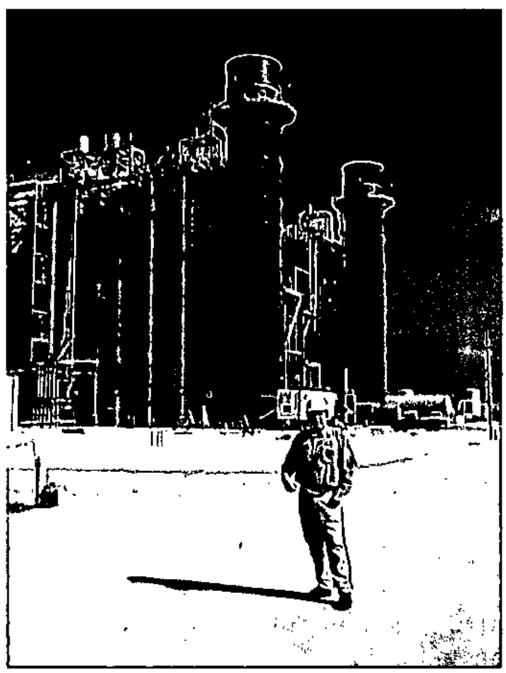


Figure 8 – FPC Hines Power Block I

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

In a project such as the CPV Gulfcoast Energy Center, the DLN system will reduce potential emissions from about 200 ppmvd to 9 ppmvd while firing gas. The DLN system is a sophisticated combustion system that optimizes efficiency and emissions. An SCR system at the CPV project will further reduce emissions to about 3.5 ppmvd at a substantial cost with add-on control equipment that does nothing to enhance efficiency. It increases PM formation and substitutes another pollutant (ammonia) while bringing NO_X emissions to levels equal to the uncertainty in the measurement method.

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. Temperatures on the order of 1800 °F can be achieved in supplementally-fired HRSGs with very large duct burners. An example is the Santa Rosa Energy Center, which incorporates a 585 mmBtu/hr duct burner. SNCR is not feasible for un-fired HRSG planned for the CPV project.

$SCONO_X$™

$SCONO_X$ is a catalytic add-on technology (and registered trademark) that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[7]

California regulators and industry sources have stated that the first 250 MW block to install $SCONO_X$ will be at PG&E's La Paloma Plant near Bakersfield.[8] The overall project includes several more 250 MW blocks with SCR for control.[9] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine equipped with $SCONO_X$™.

$SCONO_X$ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the $SCONO_X$ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions.

Recently EPA Region IX acknowledged that $SCONO_X$ was demonstrated in practice to achieve 2.0 ppmv NO_X.[10] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv. More recently, Goaline submitted information to EPA and states in support of its contention that the technology has achieved 1 ppmvd in practice.[11]

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[12] The technology is under consideration for on . of the seven combined cycle units to be installed at the TECO Bayside Project (repowering of coal-fired Gannon Station Units 5 and 6).

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 76 TPY of SO_2 and 12 TPY of SAM. The Department expects that emissions will be lower because of the limited oil consumption and because typical natural gas distributed in Florida that contains less than the 0.0065% sulfur specification proposed as BACT.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 720 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. As previously mentioned, the NO_X control technology of SCR increases PM/PM_{10} emissions due to formation of ammonium nitrates and ammonium sulfates. The problem is more significant when firing fuel oil (despite the low sulfur specification). This effect will be minimized by limiting fuel oil firing to less than 720 hours per year and limiting ammonia emissions (slip) to 5 ppmvd.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO. There is a great deal of uncertainty regarding actual CO emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions have actually been reported from several facilities without use of oxidation catalyst. For example, although Westinghouse does not offer a single digit CO guarantee on the 501F, the units installed at the FPC Hines Energy Complex achieved CO emissions in the range of 1-3 ppmvd on both gas and fuel oil.[13] GE 7FA units achieved similar results when firing gas at the FPL Martin Power Plant.[14]

CO emissions *should* be low (at least at full load) because of the very high combustion temperatures characteristic of "F-Class" turbines. It appears that contract writing has not yet "caught up" with the field experience to consistently guarantee low CO emissions for F-Class units, at least at high loads.

One alternative is to complete the combustion by installation of an oxidation catalyst. Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[15]

The limit proposed by CPV when firing natural gas is 9 ppmvd at the entire operating range between 50 and 100 percent of full load. This is consistent with the description of the DLN-2.6 technology. A higher limit of 15 ppmvd is proposed during power augmentation. Under this mode, steam from the HRSG is re-injected into the combustors to boost power production. One consequence is that CO emissions increase. The emission limit of 20 ppmvd during limited fuel oil firing appears reasonable, although lower values are likely to be achieved.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by CPV for this project are 1.4 ppmvw for gas and 3.6 ppmvw for oil firing. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[16]

Based on the chosen equipment, the Department believes that annual VOC emissions will be less than 40 TPY. Therefore a BACT determination is not required.

BACKGROUND ON SELECTED GAS TURBINE

CPV plans to the purchase a 170 MW (nominal) General Electric 7FA combined cycle gas turbine with an unfired heat recovery steam generator (HRSG). Per the discussion above, the unit is capable of achieving and has achieved all of the emission limits proposed by CPV as BACT.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values prior to the SCR unit.[17]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the CPV project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 16 through 21.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	3.5 ppmvd @15% O_2 (gas) 10 ppmvd@15% O_2 (oil)
Carbon Monoxide	Combustion Controls	9 ppmvd (gas) 15 ppmvd (power augmentation) 20 ppmvd (oil)
Particulate Matter	Inherently Clean Fuels Combustion Controls Ammonia Slip < 5 ppmvd	20 lb/hr (gas) 53 lb/hr (oil) 10 percent Opacity
Sulfur Dioxide and Sulfuric Acid Mist	Low Sulfur Fuels	0.0065% sulfur (gas) 0.05% sulfur (oil)

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line has requested recognition of a 1.3 ppmvd NO_X value as *achieved in practice*.
- There are several projects for large turbines requiring SCR with a NO_X emission limit of 2 ppmvd.
- The "Top" technology in a top/down analysis will achieve 2 ppmvd by either $SCONO_X$ or SCR.
- CPV chose SCR over $SCONO_X$ for technical and economic reasons. The Department does not necessarily accept the technical rationale. The Department does not necessarily accept the economic figures submitted by CPV of $2,835 and $24,916 per ton of NO_X removed by SCR and $SCONO_X$ respectively.
- If the costs submitted by CPV were *doubled* to $5,600 per ton by SCR and *halved* to $12,500 per ton by $SCONO_X$, the former control technology would still be more cost-effective than the latter. The difference of almost $7,000 per ton of NO_X removed is sufficient reason to select SCR over $SCONO_X$ for this project.
- CPV proposes a NO_X limit of 3.5 ppmvd while firing natural gas. This is equal to the lowest emission rate in Florida and nearby states to-date.
- Based on previous projects such as KUA Cane Island, the Department believes that the costs of NO_X control by SCR are on the order of $6,000 per ton when ammonia emissions are held to 5 ppmvd.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[18]

- Although further reduction to 2 ppmvd is possible (though difficult to measure), the marginal costs escalate rapidly and ammonia emissions increase.
- The Department agrees with CPV that 3.5 ppmvd (with 5 ppmvd ammonia slip) while firing natural gas constitutes BACT. This value for the SCR option takes into consideration the uncertainties mentioned above and minimize the negative effects of ammonia emissions.
- The Department previously documented the environmental and cost impacts associated with the use of SCR to achieve 3.5 ppmvd of NO_X at the KUA Cane Island Project in comparison with DLN to achieve 9 ppmvd NO_X.
- EPA Region IV determined that there are no there were "no unusual site-specific conditions associated with the KUA project to indicate that the use of SCR to achieve NO_X emissions of 3.5 ppm would cause greater problems than experienced elsewhere at other similar facilities."
- Ammonia is used very large quantities at adjacent or nearby fertilizer plants in Polk, Hillsborough and Manatee Counties to make ammoniated fertilizers. Therefore there are no obvious site-specific conditions that would make it unadvisable to use ammonia at the CPV project.
- The conclusion is that the cost and environmental impacts of SCR for this project are acceptable in view of the NO_X reduction.
- The CO limits of 9 ppmvd while firing natural gas and 15 ppmvd under power augmentation are low and within the range of recent BACT determinations for combustion turbines in the Southeast. The CO limit during the limited hours of fuel oil firing will be set at 20 ppmvd (full load).
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.
- The Department agrees that inlet air filtration, good combustion, and use of inherently clean fuels is BACT for PM/PM_{10}. Furthermore, the Department will set the ammonia limit at 5 ppmvd to minimize additional PM formation.
- PM_{10} emissions will be very low and difficult to measure. The values of 20 and 53 lb/hr for natural gas and oil respectively will be included in the permit. These values include front and back-half catch.
- The Department will set a visible emissions BACT limit at 10 percent. The Department will rely on VE observation as a surrogate for PM/PM_{10} BACT compliance (after the initial PM/PM_{10} test).

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
PM/PM_{10}	Method 5 (Front plus back-half catch, Initial test, thereafter VE as surrogate)
Volatile Organic Compounds	Method 25A corrected by methane from Method 18 (Initial tests only)
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
Carbon Monoxide	CO CEMS
NO_X (continuous 3-hr)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (initial and annual)	Annual Method 20 (can use RATA if at capacity); Method 7E

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 24 of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C. and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: One hour in simple cycle or following a shutdown less than or equal to 8 hours.
Warm Start: Two hours following a shutdown between 8 and 48 hours.
Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the HRSG has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[19]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Teresa Heron, Review Engineer, New Source Review Section
A. A. Linero, P.E. Administrator, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: Approved By:

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

REFERENCES

[1] Paper. Cohn, A. and Scheibel, J., EPRI. Current Gas Turbine Developments and Future Projects. October 1997.

[2] Telecom. Linero, A.A., FDEP and Chalfin, J., GE. NO_X control technology for fuel oil.

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[11] Letter. Bedwell, A.F., Goal Line to Linero, A.A., FDEP. Re: $SCONO_X$ 21000 Hour Report. September 29, 2000.

[12] News Release. ABB Alstom Power, Environmental Segment. ABB Alstom Power to Supply Groundbreaking $SCONO_X$™ Technology. December 1, 1999.

[13] Reports. Cubix Corporation. "Initial Compliance Reports – Power Block I." February and May 1999.

[14] Report. Florida Power & Light. "Final Dry Low NO_X Verification Testing at Martin Combine Cycle Plant." August 7, 1995.

[15] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[16] Telecon. Vandervort, C., GE, and Linero, A.A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."

[17] Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."

[18] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[19] General Electric. Combined Cycle Startup Curves. June 19, 1998.

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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.