Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

March 7, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ben Jacoby, Director
Pompano Beach Energy Center, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

Re: DEP File No. 0112515-001-AC (PSD-FL-304)
Pompano Beach Energy Center
Three Simple Cycle Combustion Turbines

Dear Mr. Jacoby:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Pompano Beach Energy Center to be located in Pompano Beach, Broward 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 other 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 or contact him at 850/921-9523.

Sincerely,

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

CHF/al

Enclosures

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee: DEP File No. 0112515-001-AC (PSD-FL-304)

Pompano Beach Energy, L.L.C.
Pompano Beach Energy Center
Broward County

Project type:

Project is construction of three 170-megawatt GE PG7241FA gas and oil-fired simple cycle combustion turbine-electrical generators with 80-foot stacks, inlet air chillers, two fuel oil storage tanks, four wet mechanical draft cooling towers, a gas heater, and ancillary equipment. Units will operate maximum of 3,500 hours per year per unit of which 1000 hours per year per unit may be on No. 2 distillate fuel oil. The facility will be further limited by two hours of operation for every hour of operation that fuel oil is used beyond 250 hours per unit over a 12-month period. Therefore if fuel oil is consumed for 1000 hours per unit during a 12-month period, then total facility operation is restricted to 2000 hours per unit.

The units must meet the manufacturer's "new and clean" nitrogen oxides performance guarantee of 9 parts per million by volume, dry, at 15% oxygen (ppmvd) while burning natural gas. The continuous (24-hour) BACT NO_X limits are 9 ppmvd when operating on natural gas and 42 ppmvd by wet injection when burning fuel oil. A report outlining the possibilities for NO_X reduction must be prepared if the facility uses fuel oil for more than 500 hours per unit during a 12-month period. Other pollutants, including particulate matter (PM/PM_{10}), carbon monoxide, volatile organic compounds, sulfur dioxide, and sulfuric acid mist will be controlled by good combustion and use of clean fuels.

Projected impacts from the proposed project emissions are all less than the applicable significant impact limits (SILs) corresponding to the nearby Class II areas. Except for SO_2, projected impacts are less than the applicable SILs corresponding to the Class I Everglades National Park. The project will not cause or contribute to a violation of any National Ambient Air Quality Standard or Increment. The National Park Service advised us that they have no adverse comments regarding this project.

I HEREBY CERTIFY that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).

3/2/01

A. A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

3/2

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Pompano Beach Energy, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

DEP File No. 0112515-001-AC (PSD-304)
Pompano Beach Energy Center
Broward 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, Pompano Beach Energy, L.L.C., applied on October 23, 2000 (revised December 15) to the Department for an air construction permit to construct three 170-megawatt dual-fuel combustion turbine-electrical generators and ancillary equipment for the Pompano Beach Energy Center to be located in Pompano Beach, Broward County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided 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 concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. The Department will also accept written and oral comments at a public hearing (meeting) to be held as described in the enclosed Public Notice. 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 comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying

(implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/7/01 to the person(s) listed:

Ben Jacoby, PBE LLC*
Gregg Worley, EPA
John Bunyak, NPS
Melissa Meeker, DEP SED
Blair Burgess, P.E., ENSR
Director, Broward County DPEP*
Chair, Broward County BCC*
Commissioners, Districts 1,2,3 and 9, Broward County BCC
Mayor, Pompano Beach*
Mayor, Deerfield Beach*
Mayor, Coral Springs*
Mayor, Coconut Creek*
Mayor, Margate*
Mayor, Parkland*

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 (Clerk) 3/7/01 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0112515-001-AC (PSD-FL-304)

Pompano Beach Energy Center
Broward County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Pompano Beach Energy, L.L.C (an affiliate of Enron North America). The permit is to construct three 170-megawatt (MW) dual-fuel combustion turbines with inlet chillers, three mechanical draft cooling towers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Pompano Beach Energy Center to be located at 3300 Northwest 27th Avenue in Pompano Beach, Broward County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Pompano Beach Energy, L.L.C. (affiliate of Enron North America), 1400 Smith Street, Houston, Texas 77002-7631.

The new units will be nominal 170 MW General Electric PG7241FA combustion turbine-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas. The backup fuel will be maximum 0.05 percent sulfur distillate fuel oil. The facility will be permitted to operate no more than an average of 3,500 hours per installed unit during any consecutive 12-month period. Fuel oil firing will be permitted for 1000 hours (within the 3,500 hours) per installed unit during any consecutive 12-month period. However the total hours of operation will be reduced by two hours for each fuel oil-fired hour in excess of an average of 250 per installed unit. Therefore if the facility uses fuel oil for 1000 hours per unit, total hours of operation (for both fuels combined) will be 2000 hours per unit.

NO_x emissions will be controlled by Dry Low NO_x (DLN-2.6) combustors. The units must meet a continuous emission limit of 9 parts per million by volume, dry at 15 percent oxygen (ppm). NO_x will be controlled to 42 ppm by wet injection when firing fuel oil. Sulfuric acid mist, SO_2, and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emissions from the combustion turbines in tons per year are summarized below. These include the minor emissions from the fuel oil storage tanks, the gas heater and the cooling towers.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	41	25/15
CO	146	100
NO_x	573	40
VOC	12	40
SO_2	166	40
Sulfuric Acid Mist	25	7

Air quality impact analyses were conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels. The predicted impacts in the Everglades National Park are also less than the applicable Class I significant impact levels, with the exception of SO_2. Therefore, multi-source modeling was required for SO_2. The maximum predicted PSD Class I SO_2 increments consumed in the Everglades National Park by all increment consuming sources (since 1975-77) in the area, including this project, will be as follows:

Averaging Time	Increment Consumed All Sources/This Project ($\mu g\ SO_2/m^3$)	Allowable Increment All Sources ($\mu g\ SO_2/m^3$)	Percent Increment Consumed All Sources/This Project (percent)
3-hour	9.6 / 1.1	25	48 / 4
24-hour	4.0 / 0.2	5	80 / 4

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, 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 concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments 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. Written and oral comments will also be received at a public meeting scheduled for March 26, 2001 at 7:30 p.m. at the Pompano Beach Civic Center, East Banquet Room, 1801 N.E. 6th Street, Pompano Beach. Department personnel will also be available between 6 and 7:00 p.m. for informal discussions regarding the proposed permit. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

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 Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32301 Telephone: 850/488-0114 Fax: 850/922-6979	Dept. of Environmental Protection Southeast District Office 400 North Congress Avenue West Palm Beach, Florida 33416 Telephone: 561/681-6600 Fax: 561/681-6755	Broward County Department of Planning & Environmental Protection 218 Southwest 1st Avenue Fort Lauderdale, Florida 33301 Telephone: 954/519-1220 Fax: 954/519-1495

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 draft permit, technical evaluation and preliminary BACT determination can be accessed at http://www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Pompano Beach Energy Center

Three 170-Megawatt Combustion Turbines
One 2.5-Million Gallon Fuel Oil Storage Tank
One 0.6 Million Gallon Fuel Oil Storage Tank
Four Wet Mechanical Draft Cooling Towers
Gas-fired Heater

Broward County

DEP File No. 0112515-001-AC (PSD-FL-304)

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

March 7, 2001

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Pompano Beach Energy, L.L.C. (PBE)
1400 Smith Street
Houston, Texas 77002-7631

Authorized Representative: *Mr. Ben Jacoby*

1.2 Reviewing and Process Schedule

10-23-00: Date of Receipt of Application
12-15-00: Received Revised Application
12-20-00: Application Complete
03-07-01: Distributed Intent to Issue

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The Pompano Beach Energy Center will be located in Broward County near the southeast coast. The proposed site is East of the Florida Turnpike and South of Sample Road. The street address will be 3300 Northwest 27th Avenue in Pompano Beach. The location is approximately 60 kilometers North-northeast of the Everglades National Park. The UTM coordinates for this facility are Zone 17; 556.67 km E; 3028.55 km N.

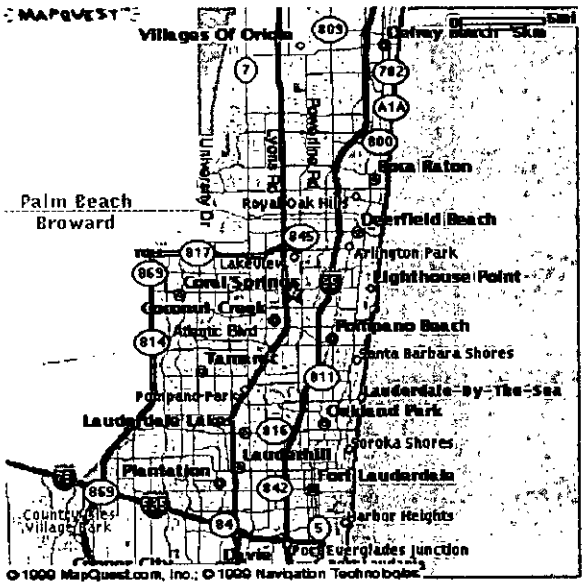


Figure 1 – Regional Location

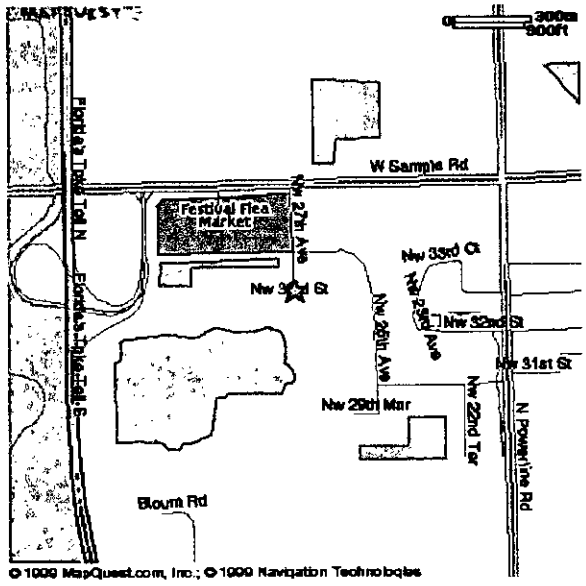


Figure 2 – Proposed Project Site

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 proposed facility will generate 510 megawatts (nominal MW) of electrical power. 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.

This facility is not 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 250 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), and a Best Available control Technology determination is required. Given that emissions of at least one single criteria pollutant will exceed 250 TPY, PSD Review and a BACT determination are required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. These values are: 40 TPY for NO_X, SO_2, and VOC; 25/15 TPY of PM/PM_{10}; 7 TPY of Sulfuric Acid Mist (SAM); and 100 TPY of CO.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
004	Fuel Storage	One 2.5-million gallon fuel oil storage tank and one 0.6-million gallon fuel oil storage tank
005	Fuel Heating	One 13 million Btu per hour Natural Gas heater
006	Inlet Air Chilling	Four 2-cell wet mechanical draft cooling towers

Pompano Beach Energy (PBE) proposes to construct three nominal 170 MW General Electric PG7241FA simple cycle, intermittent duty combustion turbine-electrical-generators with inlet air chillers, cooling towers, 80-foot stacks, two fuel oil storage tanks, a natural gas heater, and ancillary equipment at the planned Pompano Beach Energy Center.

According to the revised application, the facility will emit approximately 573 tons per year (TPY) of NO_X, 146 TPY of CO, 41 TPY of PM/PM_{10}, 166 TPY of SO_2, 12 TPY of VOC, and 25 TPY of sulfuric acid mist SAM.

Significant emission rate increases per Table 212.400-2, F.A.C. will occur for CO, SO_2, SAM, PM/PM_{10} and NO_X. A BACT determination is required for each of these pollutants. An air quality impact review is also required for CO, PM/PM_{10}, NO_X, and SO_2.

Each turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors for the control of NO_X emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. Each turbine will have a maximum heat input rating of approximately 1,700 (gas) and 1,900 (oil) mmBtu/hr lower heating value (LHV) at 30°F while operating at 100% load. The main fuel will be natural gas and the units are proposed by PBE to operate up to 3,500 hours per year per unit. PBE may fire up to 1000 hours per year per unit (average over the three units) of maximum 0.05 percent sulfur distillate fuel oil. In that case, PBE may operate only 2000 hours per year per unit (average over the three units).

The key components of the GE MS 7001FA (a predecessor of the PG 7241FA) are identified in Figure 3. An exterior view is also shown. Each unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of the earlier-generation combustors supplied with the MS7001FA.

4. PROCESS DESCRIPTION

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 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.

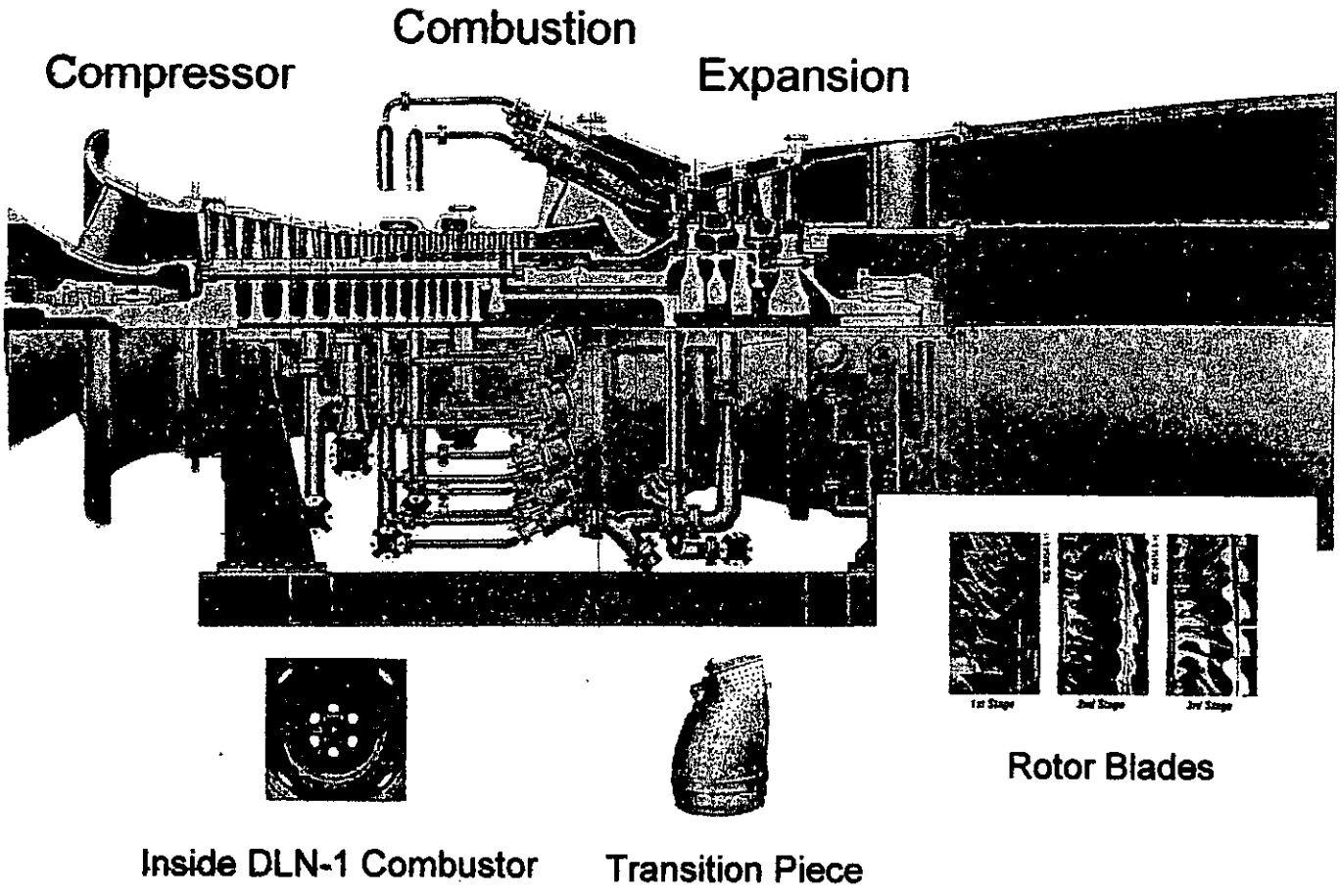
Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of 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.

Figure 4 is a simplified process flow diagram of the proposed Pompano Beach Project. In the Pompano Beach Project, the units will operate as peaking units in the simple cycle mode. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is approximately 35 percent for F-Class combustion turbines in the simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet air density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an inlet air cooler (fogger or chiller) can be installed ahead of the combustion turbine inlet. At an ambient temperature of 95 °F, roughly 15 MW of power can be regained per unit by using a chiller to cool the inlet air to 50 °F.

In combined cycle projects, the gas turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator. The steam, in-turn, drives another electrical generator producing an additional 80-90 MW. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

The additional process information related to the combustor design, and control measures to minimize pollutant emissions are given in the attached draft BACT determination.



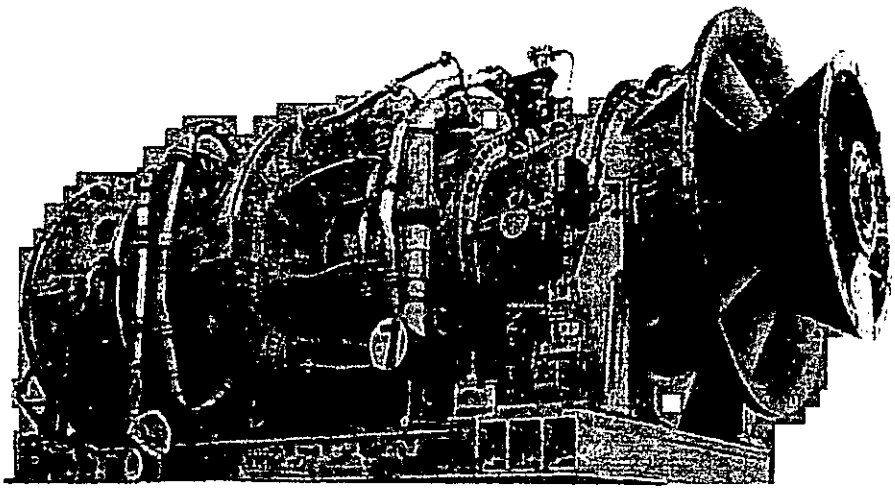


Figure 3 - Internal and External Views of Early GE 7FA

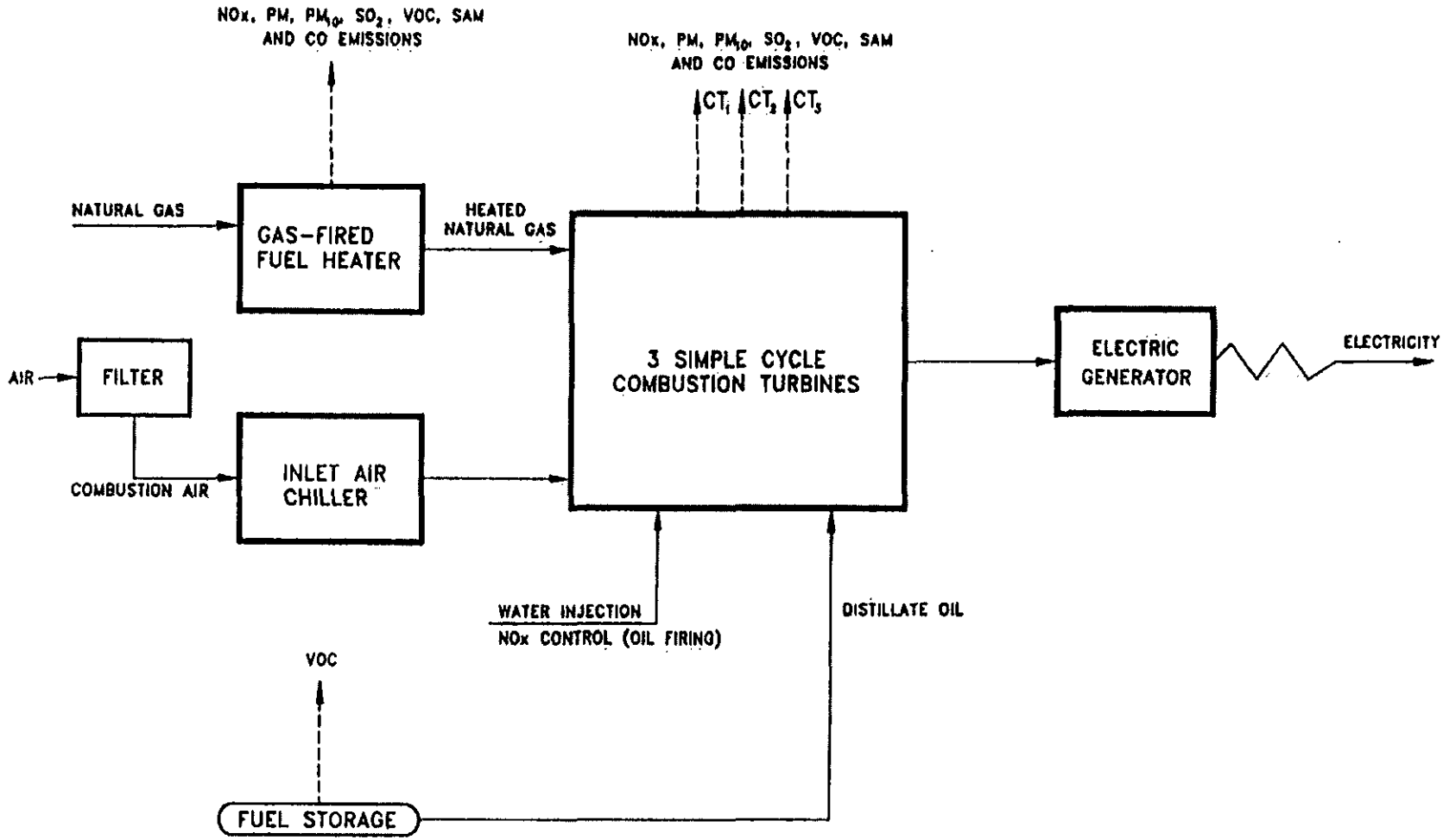


Figure 4 - Simple Cycle Process Flow Diagram

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 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 will be located in Broward 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) for the reasons given in Section 2.3, Facility Category, above.

This PSD review consists of an evaluation of resulting ambient air pollutant concentrations, and increases with respect to the National Ambient Air Quality Standards and Increments as well as a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO, SO_2, SAM 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

The emission units affected by this air construction 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 related to air:

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 60	Applicable sections of Subpart A, General Requirements, Subparts Dc, GG, and Kb
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)

5.2 Broward County Rules

Section 27-175(g)	General Prohibitions, Cumulative Impacts
Section 27-176(c)(2)b.	Permit Application Requirements, Cumulative Impacts
Section 27-176(c)(2)c.	Permit Application Requirements, Pollution Prevention Plan
Section 27-178	Pollution Prevention Planning

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2, F.A.C.): PM/PM_{10}, SO_2, NO_X, CO, SAM, and negligible quantities of fluorides (F), mercury (Hg) and lead (Pb). 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 are summarized in the Draft BACT document and Specific Condition Nos. 14-20 of Draft Permit PSD-FL-304.

6.2 Emission Summary

The annual emissions increases for all PSD pollutants as a result of the project are presented below:

PROJECT EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Gas Firing[1]	Oil Firing[2]	Total[3]	PSD Significance	PSD REVIEW?
PM/PM_{10}	95	51	41	25	Yes
SO_2	56	150	166	40	Yes
NO_X	315	482	573	40	Yes
CO	157	100	146	100	Yes
Ozone (VOC)	16	7	12	40	No
Sulfuric Acid Mist	8	23	25	7	Yes
Total Fluorides	~0	~0	0.09	3	No
Mercury	~0	0.003	0.003	0.1	No
Lead	~0	0.03	0.03	0.6	No
HAPs	5	3	5	NA	NA

1. Based on 3,500 hours of gas firing per year per unit. Includes gas heater. Reference inlet air chiller temperature is 50 °F.
2. 1000 hours of fuel oil firing per year per unit. Includes storage tanks, gas heater, towers.
3. Based on 1,000 hours of natural gas and 1000 hours of fuel oil firing per year per unit. Includes storage tanks, gas heater, towers.

6.3 Control Technology

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may be potentially emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_X, SO_2, CO, SAM, and PM/PM_{10}. Emissions control will be accomplished primarily by good combustion of clean natural gas and the limited use of low sulfur (0.05 percent) distillate fuel oil. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen

oxides formation potential. 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 Impact 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, AAQS or de minimis monitoring levels for SAM; the BACT determination will set the emission limits 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 in the Class II area in the vicinity of the project. Therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required in the Class II area. The nearest PSD Class I area is the Everglades National Park (ENP) located about 60 km to the south and southwest. The applicant's PSD Class I air quality analysis showed significant impacts for only SO_2, and only for the 24-hour and 3-hour averaging times. Therefore, a cumulative PSD Class I increment analysis was required for SO_2 for these averaging times. Also, the maximum predicted impacts for all pollutants 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_2 in the surrounding Class II Area;
- A significant impact analysis for PM_{10}, SO_2, and NO_2 in the ENP;
- A 24-hour and 3-hour averaging time SO_2 PSD Class I increment analysis for the ENP;
- 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 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimus concentration.

The table below shows that predicted impacts from the combustion turbines are substantially less than the respective de minimus levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant. Additionally, the approximate high values measured at existing ambient monitoring sites in Broward County are included for comparison purposes.

Broward County has an excellent monitoring program. Installation of additional monitors near the proposed site will probably not show any increases from the plant because of the very low impact levels. Basically, the highest contribution from the plant would be on the order of 1 percent or less of the highest measured concentrations. This is less than the inherent measurement error in the sampling and analytical techniques.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMUS AMBIENT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimus Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimus?
PM_{10}	24-hour	0.4	10	~ 40	NO
NO_2	Annual	0.03	14	~ 20	NO
SO_2	24-hour	0.08	13	~ 50	NO
CO	8-hour	3	575	~ 6000	NO

6.4.3 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) station at West Palm Beach, Florida (surface and upper air data). The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

PSD Class I Area

Since the PSD Class I ENP is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and two Air Quality Related Values (AQRVs), regional haze and deposition of sulfur and nitrogen compounds. 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.

CALPUFF was first run in screen mode using ISCST3 meteorological input data. Five years of regionally representative data were used as input. The source of the surface data was the Solar and Meteorological Surface Observation Network (SAMSON) data set that has been produced by the National Climatic Data Center (NCDC). Hourly SAMSON surface data for Miami International Airport supplemented with precipitation data obtained from NCDC for the period 1986 through 1990 was used along with concurrent upper air data from West Palm Beach.

Since CALPUFF screening runs showed significant impacts for at least one pollutant, refined CALPUFF modeling was required to further analyze potential impacts. The major difference between CALPUFF screening and CALPUFF refined modeling is the incorporation of three-dimensional meteorological wind fields. Five years of surface and upper air meteorological data (1986-1990) were processed. The applicant used the California Meteorological (CALMET) model to generate a three-dimensional gridded modeling domain of hourly temperature and wind fields over a modeling domain centered on the northern boundary of the ENP. Meteorological surface data and upper air data used were from Key West, Miami, Tampa and West Palm Beach. Hourly precipitation data were obtained from Miami, Moorehaven, Key West, Tampa, West Palm Beach, Venice, Fort Myers, Melbourne and Homestead.

6.4.4 Significant Impact Analysis

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. 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 which 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 is exempted from doing any further modeling.

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50 meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced receptors at 100 meters apart starting at and extending to 3,000 meters from the fence line. Beyond 3000 meters, a spacing of 500 meters was used out to 5,000 meters from the facility. From 6 to 10 kilometers, a spacing of 1000 meters was used. Between 10 and 20 kilometers, a spacing of 2000 meters was used.

For the Class I screening analysis four rings of receptors were centered on the facility at distances bracketing the ENP. These distances represent the nearest boundary, the central portion, and the farthest boundary of the ENP with respect to the proposed project. Receptors were placed at one-degree intervals over a 360-degree arc along each ring. Screening model runs showed insignificant impacts for all pollutants, except for SO_2. Therefore, a refined CALPUFF analysis for SO_2 was performed. The refined receptor grid for evaluating SO_2 impacts consisted of receptors placed at intervals of 1 kilometer along the boundary of the ENP. These Class I boundary receptors were supplemented by receptors placed along portions of the receptor rings used in the screening level analysis that were located in the ENP.

The tables below show the results of the significant impact modeling for the Class II and Class I areas:

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	0.01	1	NO
	24-Hour	0.8	5	NO
	3-Hour	3.9	25	NO
PM_{10}	Annual	0.007	1	NO
	24-Hour	0.4	5	NO
CO	8-Hour	3	500	NO
	1-Hour	11	2000	NO
NO_2	Annual	0.03	1	NO

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

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

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.004	0.2	NO
	24-hour	0.19	0.3	NO
NO_2	Annual	0.021	0.1	NO
SO_2	Annual	0.01	0.1	NO
	24-hour	0.22	0.2	YES
	3-hour	1.11	1	YES

The results of the significant impact modeling for the ENP show that there are no significant impacts predicted due to PM_{10} and NO_2 emissions from this project; therefore, no further modeling was required in the Class I area for these pollutants. However, significant impacts were predicted for SO_2 for the 24-hour and 3-hour averaging times. Therefore, further multi-source PSD increment modeling for SO_2 was required for these averaging times.

6.4.5 Broward County Analysis

The Broward County Code Section 27-175 and 27-176(c)(2)b prohibit major sources from allowing emissions of criteria pollutants in quantities that would reduce by more than one half the margin between the existing ambient concentrations and the applicable NAAQS. The Broward County Department of Planning and Environmental Protection (DPEP) provided 1999 ambient monitoring data to the applicant from sites throughout the County. These data were derived from eight monitoring sites for PM_{10}, one for SO_2, one for NO_2 and five for CO. The results were submitted by the applicant to DPEP for review and are tabulated below.

COMPLIANCE DEMONSTRATION FOR BROWARD COUNTY CODE SECTION 27.176(C)(2)(B)

Pollutant	Averaging Time	Baseline Concentration (ug/m^3)	Monitoring Site Number	NAAQS (ug/m^3)	½ [NAAQS-Baseline] (ug/m3)	Maximum Predicted Impact Of Facility
SO_2	Annual	9	28	60	25.5	0.01
	24-Hour	47	28	260	107	0.8
	3-Hour	272	28	1300	514	3.9
PM_{10}	Annual	18	28,29	50	16	0.01
	24-Hour	38	3	150	56	0.4
CO	8-Hour	6298	28	10,000	1,851	3
	1-Hour	10,877	18	40,000	14,563	11
NO_2	Annual	20	31	100	40	0.05

The table above shows that this project will consume much less than one-half of the margin between the maximum baseline concentration and the NAAQS. The project's impact is less than one percent of this margin for all the criteria pollutants modeled.

6.4.6 PSD Class Increment Analysis for SO_2

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 for SO_2 (the baseline year was 1975 for existing major sources of SO_2). The maximum predicted SO_2 PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table. The table shows that the maximum predicted impacts are less than the allowable Class I SO_2 increments in the ENP.

PSD CLASS I INCREMENT ANALYSIS - ENP

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater Than Allowable Increment?	Allowable Increment ($\mu g/m^3$)
SO_2	24-hr	4.0	NO	5
	3-hr	9.6	NO	25

6.4.7 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas and oil-fired combustion turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. An analysis of sulfur and nitrogen deposition impacts in the ENP was done. Based on National Park Service (NPS) criteria, no adverse impacts were predicted. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, SO_2 and SAM as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS. The project impacts are less than the significant impact levels, 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.

Impact On Visibility and Regional Haze

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. The contribution to smog in the area will be minimal. A regional haze analysis for the ENP was submitted by the applicant. Based on NPS criteria, no adverse impacts were predicted.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area.

The type of project proposed has a small overall physical "footprint," and among the lowest air emissions per unit of electric power generating capacity for intermittent duty.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to 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.

A. A. Linero, P.E., Administrator
Cleve Holladay, Meteorologist

DRAFT PERMIT

PERMITTEE:

Pompano Beach Energy, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

Permit No.	PSD-FL-304
Project No.	0112515-001-AC
SIC No.	4911
Expires:	December 31, 2003

Authorized Representative:
Mr. Ben Jacoby

PROJECT AND LOCATION:

This air construction permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers; four mechanical draft cooling towers; one 2.5-million gallon fuel oil storage tank; one 0.6 million gallon fuel oil storage tank; a gas-fired natural gas fuel heater; and three 80-foot stacks. The combustion turbines will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_x (DLN-2.6) combustors and wet injection capability.

The project will be located at 3300 Northwest 27th Avenue, Pompano Beach in Broward County. UTM coordinates are: Zone 17; 556.7 km E; 3028.5 km N.

STATEMENT OF BASIS:

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to construct 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).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions
Appendix GG	40 CFR 60, Subpart GG

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers, three 80-foot stacks, one 2.5-million gallon fuel oil storage tank, one 0.6-million gallon storage tank, a gas heater and ancillary equipment. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

EMISSIONS UNIT ID NO.	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 170 megawatt combustion turbine-electrical generator set with inlet air chiller
002	Power Generation	One nominal 170 megawatt combustion turbine-electrical generator set with inlet air chiller
003	Power Generation	One nominal 170 megawatt combustion turbine-electrical generator set with inlet air chiller
004	Fuel Storage	One 2.5-million gallon fuel oil storage tank and one 0.6-million gallon fuel oil storage tank
005	Fuel Heating	One 13 million Btu per hour natural gas heater
006	Inlet Air Chilling	Four 2-cell wet mechanical draft cooling towers

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 not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 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). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist

(SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

PERMIT SCHEDULE

- 10/23/00 Received Application
- 12/15/00 Received Revised Application
- 12/20/00 Application Complete
- 03/07/01 Distributed Intent to Issue
- xx/xx/01 Notice of Intent published in _____

RELEVANT DOCUMENTS:

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

- Application received on October 23, 2000;
- Letter from Broward County Department of Planning and Environmental Protection dated November 21, 2000;
- Letters from Enron North America dated December 1 and December 14, 2000;
- Revised Application received on December 15, 2000;
- Pollution Prevention Plan received on December 20, 2000;
- Application errata pages received January 19, 2001;
- Letter from Broward County Department of Planning and Environmental Protection dated February 8, 2000;
- CALPUFF air quality and Class I impact analysis received February 16, 2001;
- Department's Intent to Issue and Public Notice Package dated February 27, 2001;
- Letter from U.S. EPA Region IV dated _____;
- Letter from National Park Service dated _____; and
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

1. Regulating Agencies: 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 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the Broward County Department of Planning and Environmental Protection, 218 Southwest 1st Avenue, Fort Lauderdale, Florida 33301 and phone number 954/519-1220. Copies of all such reports, tests, and notifications shall also be submitted to the Department's Southeast District Office at P.O. Box 15425, West Palm Beach, Florida 33416-5425.
2. 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.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. 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.]
5. 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]
6. PSD Expiration Approval: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination Revision: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation (e.g. conversion to combined-cycle operation), oil firing, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

8. Completion of Construction: The permit expiration date is December 31, 2003. Physical construction shall be complete by June 30, 2003. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

9. Permit Extension: The permittee, for good cause, may request that this construction 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. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least ninety days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and a copy to the Broward County DPEP. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

11. 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.]

APPLICABLE STANDARDS AND REGULATIONS

1. General Applicability: Unless otherwise indicated in this permit, the construction and operation of the subject emission units 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, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Construction Authorization: The permittee is authorized to:

   a. EUs 001-003: Construct power generation facilities consisting of three simple cycle combustion turbines with a nominal generating capacity of 170 MW each. (Each unit is also subject to Subpart GG of 40 CFR 60, an NSPS for gas turbines as specified in Appendix GG of this permit.)

   b. EU 004: Construct fuel storage facilities consisting of one 2.5 million gallon distillate fuel oil storage tank and one 0.6 million gallon distillate fuel oil storage tank. (Each unit is also subject to Subpart Kb of 40 CFR 60, an NSPS for the storage of volatile liquids.)

   c. EU 005: Construct fuel heating facility consisting of one 13 million Btu per hour gas-fired fuel heater to heat natural gas for use by the combustion turbines.

   d. EUs 006: Construct inlet air chilling facilities consisting of four wet mechanical draft cooling towers.

   [Application, Rule 62-204.800(7)(b), F.A.C., and 40 CFR 60 Subparts GG and Kb]

3. NSPS General Provisions: Each emissions unit subject to a specific New Source Performance Standard shall also comply with all applicable General Provisions of Subpart A in 40 CFR 60, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). [Rule 62-204.800(7)(b), F.A.C.]

GENERAL OPERATION REQUIREMENTS

4. Authorized Fuels: Each gas turbine shall fire only pipeline-quality natural gas as the primary fuel and No. 2 distillate oil (or superior grade) containing a maximum of 0.05 percent sulfur by weight as a backup fuel. [Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

5. Permitted Capacity (Gas Turbines): The maximum heat input to each gas turbine shall not exceed 1,700 MMBtu per hour when firing natural gas nor 1,900 MMBtu per hour when firing distillate oil. The heat input limits are based on the lower heating value (LHV) of each fuel, 100% load, and ambient conditions of 30° F temperature, 60% relative humidity, and 14.7 psi pressure. 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

within 45 days of completing the initial compliance testing.
[Design, Rule 62-210.200(PTE), F.A.C.]

6. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.
[Rule 62-296.320(4)(c), F.A.C.]

7. 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 owner or operator shall notify the Broward County DPEP as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include pertinent information as to the cause of the problem; the 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 and the regulations.
[Rule 62-4.130, F.A.C.]

8. 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 the operation of the installed equipment. [Rule 62-4.070(3), F.A.C.]

9. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.
[Rules 62-210.650, F.A.C.]

10. Restricted Operation: No single combustion turbine shall operate more than 5,000 hours during any consecutive 12-month period. The three combustion turbines shall operate no more than an average of 3,500 hours per installed unit during any consecutive 12-month period. This amount shall be reduced by two hours for each fuel oil-fired hour in excess of an average of 250 hours per installed unit during any consecutive 12-month period. The three combustion turbines shall operate no more than an average of 1000 hours per installed unit on distillate oil during any consecutive 12-month period.
[Applicant Request, Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

CONTROL TECHNOLOGY

11. DLN Technology: Dry low NO_X (DLN-2.6) combustors shall be installed on the combustion turbine to control NO_X emissions when firing natural gas.
[Design, Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

12. Wet Injection: A water injection (WI) system shall be installed to reduce NO_X emissions when firing distillate oil. [Design, Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

13. Tuning: The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems upon completion of initial testing. DLN

systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rules 62-4.070 and 62-210.650, F.A.C.]

EMISSION LIMITS

14. Summary: Following is a summary of the emission limits and required technology.

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	11/17 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC (not PSD)	Pipeline Natural Gas Good Combustion	2.8 ppmvd @15% O_2 (Gas or Fuel Oil)
CO	Pipeline Natural Gas Good Combustion	9 ppmvd @15% O_2 (Gas) 20 ppmvd @15% O_2 (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and Limited Fuel Oil Usage	9 ppmvd @15% O_2 (Gas) 42 ppmvd @15% O_2 (Fuel Oil)

{Note: Mass emissions limits are based on full load and a compressor inlet temperature of 30° F.}

15. Nitrogen Oxides (NO_X) Emissions

a. **Initial Performance Tests**: When firing natural gas, NO_X emissions shall not exceed 62 pounds per hour nor 9 ppmvd corrected to 15% oxygen. When firing distillate oil, NO_X emissions shall not exceed 332 pounds per hour nor 42 ppmvd corrected to 15% oxygen. NO_X emissions (measured as NO_2) shall be based on a 3-hour test average as determined as determined by EPA Method 7E or 20 during initial performance tests.

b. **Continuous Compliance**: When firing natural gas, NO_X emissions from each combustion turbine shall not exceed 9 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, NO_X emissions from each combustion turbine shall not exceed 42 ppmvd corrected to 15% oxygen based on a 24-hour block average. Continuous compliance shall be demonstrated by data collected from the continuous emission monitoring system (CEMS) specified in Condition No. 29 of this section.

c. **NO_X Reduction Plan**: When the average hours of oil firing exceed 500 hours per year per unit, the permittee shall develop a NO_X reduction plan. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without adversely affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate, noting any performance problems. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Broward County DPEP for

review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised.

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

16. Carbon Monoxide (CO) Emissions: When firing natural gas, CO emissions from each combustion turbine shall not exceed 31 pounds per hour nor 9 ppmvd corrected to 15% oxygen. When firing distillate oil, CO emissions from each combustion turbine shall not exceed 70 pounds per hour nor 20 ppmvd corrected to 15% oxygen. CO emissions shall be based on a 3-hour test average as determined initial and annual EPA Method 10 performance tests. [Rule 62-212.400(BACT), F.A.C.]

17. Volatile Organic Compounds (VOC) Emissions: When firing either natural gas or distillate oil, VOC emissions from each combustion turbine shall not exceed 6 pounds per hour nor 2.8 ppmvd corrected to 15% oxygen. VOC emissions shall be based on a 3-hour test average as determined by an initial EPA Method 25A performance test. EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct the ethane and methane emissions from the measured VOC emissions. [Synthetic Minor Limit pursuant to Rule 62-212.400(BACT), F.A.C.]

18. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions: SO_2 and SAM emissions shall be limited by firing pipeline-quality natural gas ($\leq$ 2 grains of sulfur per 100 SCF of gas) as the primary fuel and No. 2 distillate oil ($\leq$ 0.05 percent sulfur by weight) as a backup fuel for no more than 1000 hours per year per unit. Compliance with the fuel specification shall be determined by Condition No. 30 of this section.
[40CFR60 Subpart GG; Rules 62-204.800(7) and 62-212.400(BACT), F.A.C.]

19. Particulate Matter (PM/PM_{10}): PM emissions shall not exceed 10 pounds per hour when firing natural gas and 17 pounds per hour when firing distillate oil based on a 3-hour test average as determined by an initial EPA Method 5 performance test. [Rule 62-212.400(BACT), F.A.C.]

20. Visible Emissions: When firing either natural gas or distillate oil, visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition No. 22 of this section, this standard applies during all operating conditions. [Rule 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the 24-hour compliance averages for NO_X. [Rule 62-210.700, F.A.C.]

22. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of the combined cycle gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

a. During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

b. Excluding startup and shutdown, operation below 50% base load is prohibited.

c. In accordance with Condition No. 29 of this section, specific data collected by the CEM systems during startup, shutdown, malfunction, and tuning may be excluded from the NO_x compliance averaging periods. If a CEM system reports emissions in excess of a 24-hour block emissions standard, the permittee shall notify the Broward County DPEP within one working day with a preliminary report 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.

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

COMPLIANCE DETERMINATIONS

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

24. Test Methods: Required tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
5	Determination of Particulate Matter Emissions from Stationary Sources (I) • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 dscf per run.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (I, A) • CEM system RATA may be used for annual compliance demonstration.
9	Visual Determination of the Opacity of Emissions from Stationary Sources (I, A)
10	Determination of Carbon Monoxide Emissions from Stationary Sources (I, A) • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography (I) • EPA Method 18 is an optional method that may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Gas Turbines (I) • Initial test is only for NOx emissions • EPA Method 7E may be substituted for the initial NOx test
25A	Determination of Volatile Organic Concentrations (I)

The methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[40 CFR 60, Appendix A; Rules 62-204.800 and 62-297.100, F.A.C.]

25. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate 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 purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2)(b), F.A.C.]

26. Compliance Test Schedules: Compliance with the allowable emissions standards shall be determined in accordance with the following schedule.

    - **Initial**: Initial (I) performance tests for each authorized fuel shall be conducted within 60 days after achieving at least 90% of the permitted capacity, but not later than 180 days of initial operation of each unit. The Department may require initial performance tests to be conducted after any modifications of air pollution control equipment (such as a change in or tuning of combustors) with a shakedown period not to exceed 100 days after restart.
    - **Annual**: Annual (A) performance tests shall be conducted during each federal fiscal year (October 1 - September 30) on each unit as indicated.

    [Rules 62-4.070(3) and 62-297.310(7), F.A.C.]

27. Compliance Determinations

    a. **CO**: Compliance with the CO emissions limits shall be demonstrated by conducting initial and annual tests for CO concurrently with NO_X, as required. Annual compliance with the CO emissions limit may be conducted at less than capacity when testing is conducted concurrently with the annual RATA testing for the NO_X CEM system.

    b. **VOC**: Compliance with the VOC emissions limits shall be demonstrated by conducting initial tests. Thereafter, the CO emissions limits shall serve as surrogate standards for VOC emissions limits. No annual testing for VOC emissions is required.

    c. **NO_X**: Compliance with the NO_X emissions limits shall be demonstrated by conducting initial performance tests, as required. Thereafter, compliance shall be demonstrated by data collected from the CEM systems, as specified in Condition No. 29 of this section.

    d. **PM/PM_{10}**: Compliance with the particulate matter emissions limits shall be demonstrated by conducting initial, concurrent tests for PM and visible emissions. Thereafter, compliance with the visible emissions limits shall be demonstrated by conducting annual

tests. In addition to the visible emissions limits, the CO emissions limits and fuel specifications shall serve as surrogate standards for particulate matter.

e. **SO_2 and Sulfuric Acid Mist**: The fuel specifications of this section effectively limit the potential emissions of SO_2 and sulfuric acid mist. The permittee shall demonstrate compliance with the fuel sulfur limits in accordance with the analysis and record keeping requirements of Condition No. 30 of this section.

[Rules 62-4.070(3) and 62-297.310(7), F.A.C.]

28. Special Compliance Tests: The DEP may request a special compliance test when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated. [Rule 62-297.310(7), F.A.C.]

MONITORING REQUIREMENTS

29. Continuous Emissions Monitoring System: The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring (CEM) system in the exhaust stack of each gas turbine to measure and record the emissions of NO_X from the gas turbines in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit. The oxygen content or the carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where NO_X emissions are monitored to correct the measured NO_X emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel being fired. The CEM system shall be used to demonstrate compliance with the CEM emission standards for NO_X specified in this permit.

a. *Data Collection.* Compliance with the CEM emission standards for NO_X shall be based on a 24-hour block average. The block average shall be calculated from 24 consecutive hourly average emission rate values. A new block average would be determined for the next 24-hour data set. Each hourly value shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis

(0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

b. *NO_X Monitor Certification.* The NOx monitors shall be certified and operated in accordance with the following requirements. The NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the CEM emission standards of this permit, missing data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 25 ppm, and the span for the upper range shall not be greater than 120 ppm, as corrected to 15% O_2.

c. *Oxygen (CO_2) Monitor Certification.* The oxygen (CO_2) monitors shall be certified and operated in accordance with the following requirements. Oxygen (and CO_2) monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to each Broward County DPEP. RATA tests required for the oxygen (and CO_2) monitors shall be performed using EPA Method 3B in Appendix A of 40 CFR 60.

d. *Data Exclusion.* Emissions data for NOx and oxygen content (or CO_2) shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards as provided in this paragraph.

(1) Periods of data excluded for startup and shutdown shall not exceed two hours in any block 24-hour period.

(2) Periods of data excluded for a documented unavoidable malfunction shall not exceed two hours in any block 24-hour period. A "documented unavoidable malfunction" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting the Broward County DPEP by telephone or fax.

All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur

entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported semi-annually to the Broward County DPEP. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall also include the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.

f. *Data Conversion.* Upon request from the Department, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

g. *Availability.* All CEM systems shall operate continuously to monitor performance of the gas turbines except for monitor breakdowns, repairs, calibration checks, and zero and span adjustments. Monitor availability shall not be less than 95% in any calendar quarter.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

30. Fuel Sulfur Limits: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

b. Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to Broward County DPEP before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the

fuel vendor. At the request of the Department or Broward County DPEP, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

31. Determination of Process Variables:

    a. The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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), F.A.C]

NOTIFICATION, REPORTING, AND RECORDKEEPING

32. Test Notifications: The Broward County DPEP shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests. [Rule 62-297.310(7)(a)9., F.A.C.]

33. NSPS Notifications: All notifications and reports required by 40 CFR60, Subpart A shall be submitted to the Broward County DPEP.

34. Annual Reports: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Broward County DPEP by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

35. Test Reports: The permittee shall submit test reports indicating the results of the required compliance tests to the Broward County DPEP 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), F.A.C.

36. Semi-Annual Reports: The permittee shall submit semi-annual excess emission reports to the Broward County DPEP. In addition to the information required in 40 CFR 60.7 and 60.334, the report shall summarize the periods of data excluded due to startup, shutdown, and unavoidable malfunction. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7(1998 version)]

37. NSPS Fuel Tank Records: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons that is used to store volatile organic liquids for which

construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons that store a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the following record keeping requirement. The permittee shall keep readily accessible records showing the dimension of the storage vessel and the capacity of the storage tank. Records shall be retained for the life of the tank. [40 CFR 60.110b(a) and (c); 40 CFR 60.116b(a) and (b); Rule 62-204.800(7)(b)16., F.A.C.]

38. Records and Reports: All measurements, records, and other data required to be maintained by the permittee 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. [Rule 62-213.440, F.A.C.]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Pompano Beach Energy Center
PSD-FL-304 and 0112515-001-AC
Broward County, Florida

BACKGROUND

The applicant, Pompano Beach Energy, L.L.C. (PBE, an affiliate of Enron North America), proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Pompano Beach Energy Center (PBEC) in Broward County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 80-foot stacks. PBE proposes to operate these units up to 3,500 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated March 7, 2001, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on October 23, 2000 (revised December 15) and included a proposed BACT proposal prepared by the applicant's consultant, ENSR.

PREPARED BY:

A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	9 ppmvd @ 15% O_2 (gas)[1] 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	9 ppmvd (gas, baseload) 20 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, 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 PBE is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the PBEC.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple cycle turbines. Two (Carson and McClellan) were permitted in ozone non-attainment areas and two (Lakeland and PREPA) were permitted as continuous duty projects. The proposed PBEC is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 11/00. 1000 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 2/2001. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 2/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Tenaska Heard, GA	960	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
RockGen Cristiana, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous
SC = Simple Cycle
INT = Intermittent

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR

FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

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.

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Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Pompano Beach project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 1000 hours per year (per CT).

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 each turbine of the Pompano Beach Project. The proposed NO_X controls will reduce these emissions significantly.

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

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 incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design 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. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X.

The 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 may occur 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.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Tests at the JEA[2] Kennedy Plant indicated that 30 ppmvd is achievable on a short-term basis.

Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[3] where water is scarce, but the Department has no information on the results. Mitsubishi (who also make a 501F) is developing a dual-fuel premixed 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.[4] The details are not available in English.

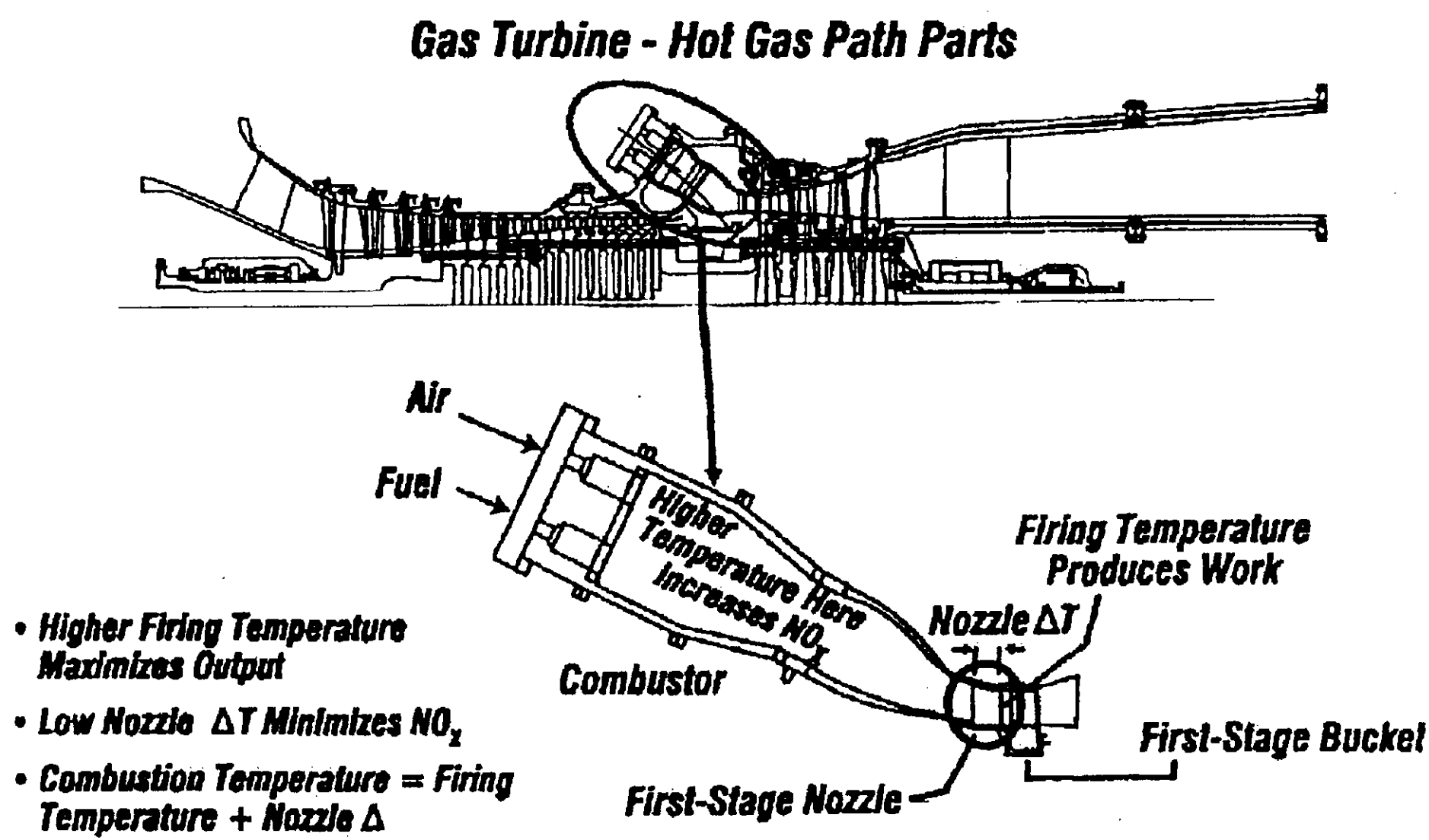

Figure 1 – Relation Between Flame Temperature and Firing Temperature

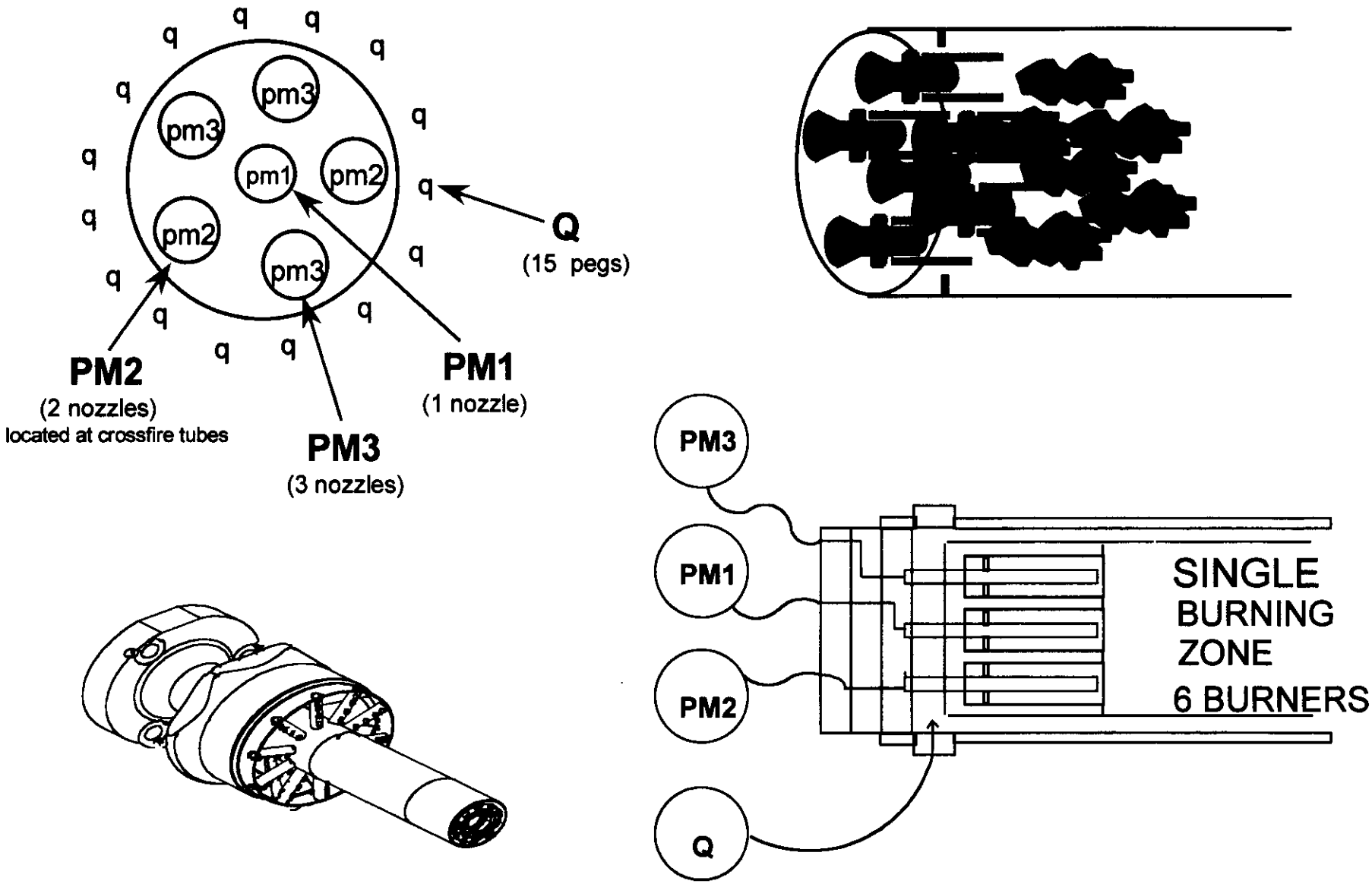

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

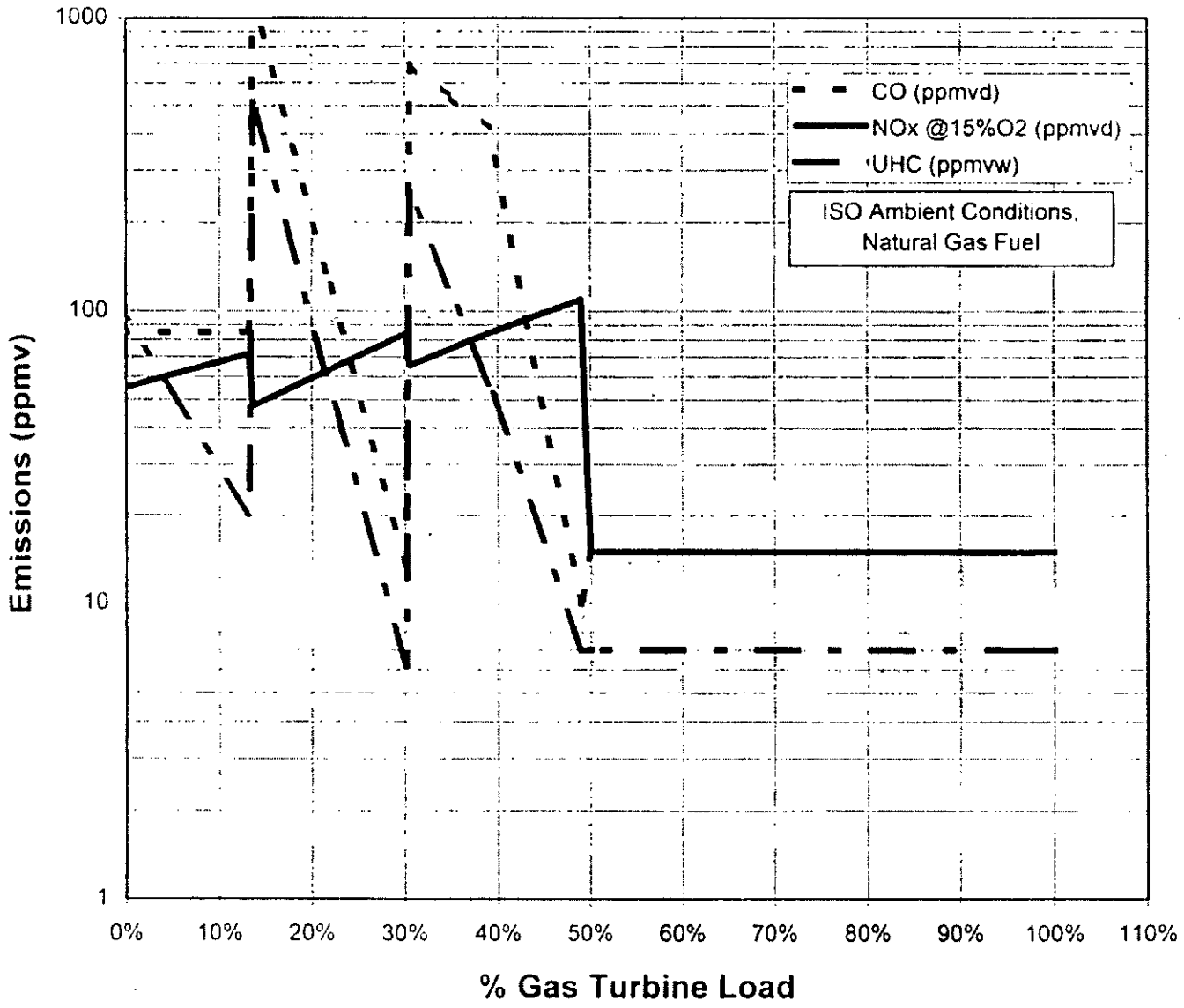

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

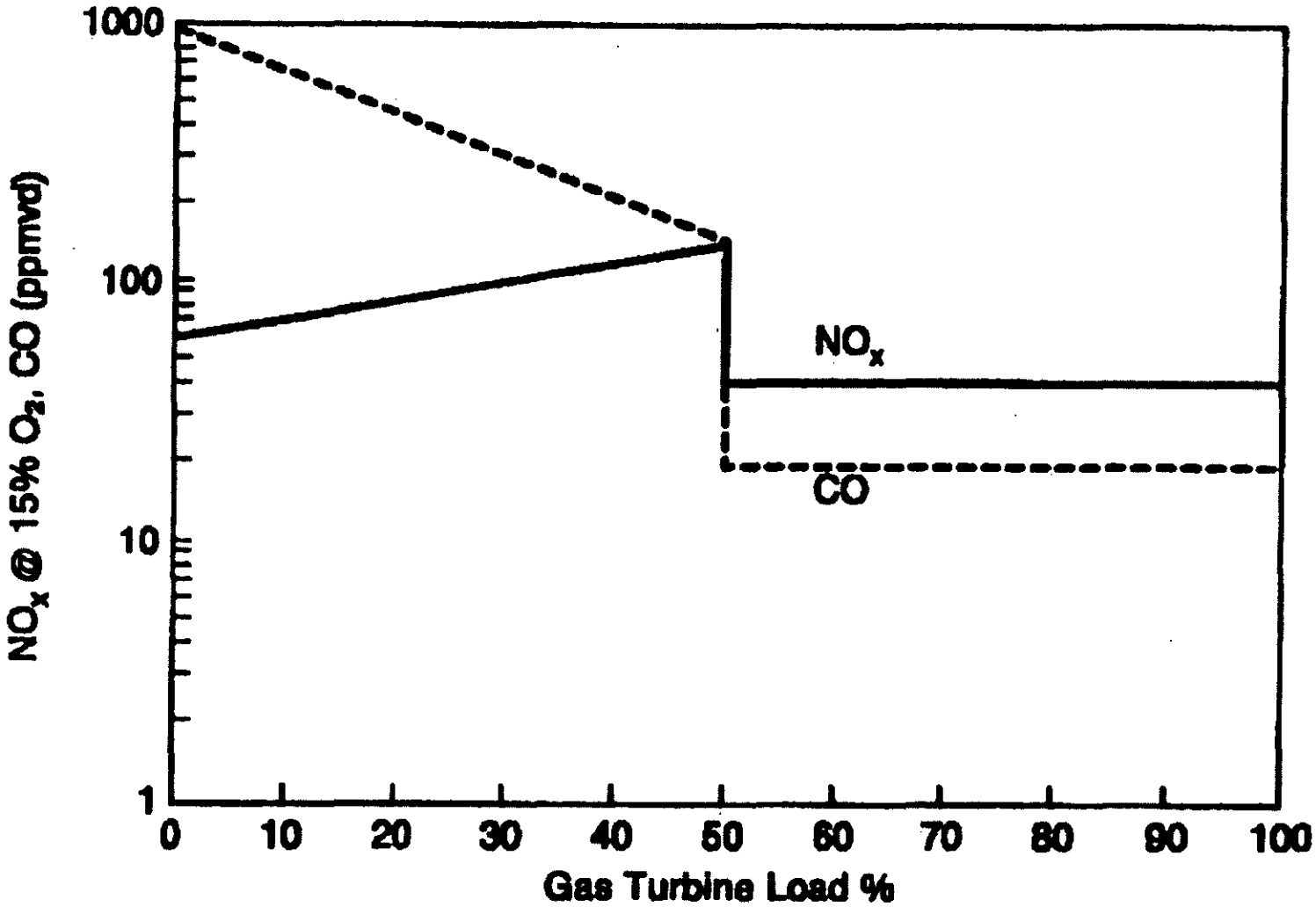

Figure 4 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

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 5 from an EPRI report.[5] 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 5.

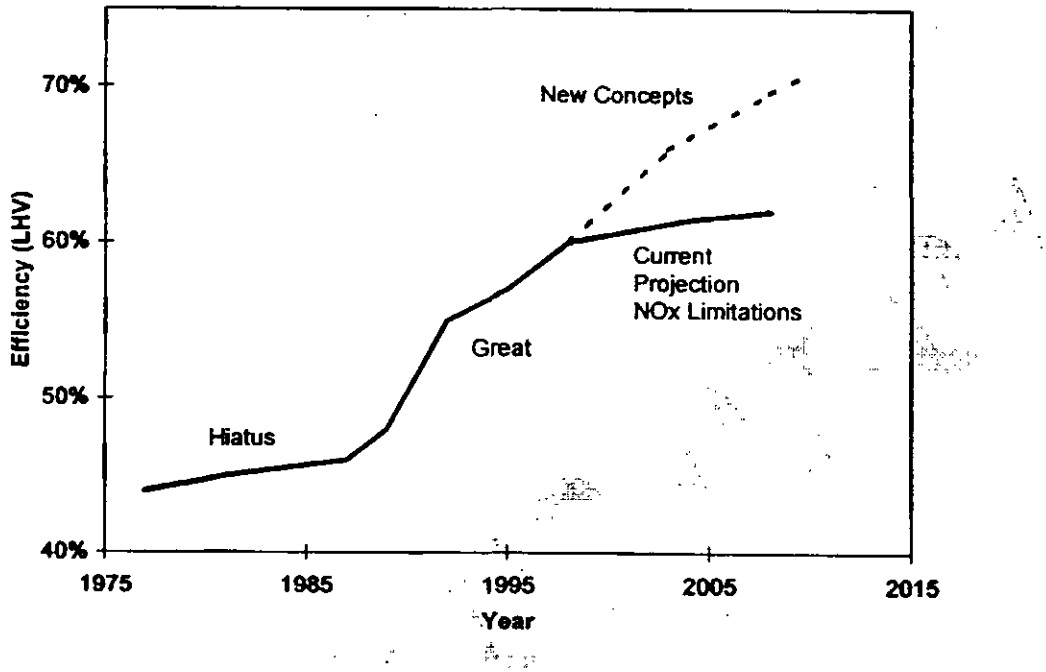

Figure 5 – Efficiency Increases in Combustion Turbines

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 (G or H Class technology) than the units planned by PBE. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. 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 instead of air cooling.

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 above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[6] 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, for example, 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™.[7] 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.[8] The project will enter commercial operation by the summer of 2001. However actual installation of XONON™ 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 Combustion

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.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

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 (Paynes Creek) project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority,[9] FPC, TECO, and Competitive Power Ventures will install SCR on combined cycle projects to achieve 3.5 ppmvd. Limits as low as 2 ppmvd NO_X have been specified using SCR on combined cycle F Class projects in various parts of the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) 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 Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

$SCONO_X$™ is a catalytic add-on technology 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.[10]

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.[11] The overall project includes several more 250 MW blocks with SCR for control.[12] 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. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [13] 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.

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."[14]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

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 190 TPY of SO_2 and 29 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf, but high enough to require a BACT determination.

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 its use is proposed for only 1000 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. Total annual emissions of PM_{10} for the project are expected to be approximately 119 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones 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 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[15]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 9 and 30 ppmvd for gas and oil respectively at baseload proposed in PBE's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by PBE for this project are 1.4 ppmvw for gas and fuel oil firing at baseload. These limits are sufficient to keep annual emissions of VOC below the 40 TPY threshold and a BACT determination is not required. 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]

BACKGROUND ON PROPOSED GAS TURBINE

PBE plans to install three nominal 170 MW General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

Typically, companies obtain a guarantee from GE to achieve 9 ppmvd NO_X during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation. With the frequent start-ups and shutdowns of the units, some applicants are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, some of them agreed to a "new and clean" limit of 9 ppmvd but requested a continuing BACT limit of 10.5 ppmvd.

As detailed in the table above, the Department has issued quite a number of permits for simple cycle GE 7FA requiring achievement of 9-10.5 ppmvd without the requirement of any additional control equipment. The ones with limits of 9 ppmvd are allowed to operate for as many as 1000 hours per year on back-up fuel oil whereas the ones permitted at 10.5 ppmvd are allowed only 750 hours per year of fuel oil. A smaller GE unit known as the 7EA can routinely achieve 9 ppmvd NO_X or lower based on numerous installations in Florida and elsewhere. The 7EA has a lower flame temperature, compression ratio, and power rating (85 versus 170 MW) than the 7FA.

The ability to meet a NO_X emission limit of 9 ppmvd by DLN technology involves a substantial efficiency and energy penalty as previously discussed. For example, the 7FA is characterized by a 15.5:1 compression ratio, a 2400 °F firing temperature, 56 percent efficiency, and produces 263 MW in combined cycle. On the other hand, GE offers a more efficient F-Class model known as the 7FB, but guarantees a NO_X limit of 25 ppmvd by DLN.

The 7FB is characterized by an 18.5:1 compression ratio, a 2500 °F firing temperature, 57.3 percent efficiency, and produces 280 MW in combined cycle. The clear implication is that the

power penalty to reduce NO_X from 25 to 9 ppmvd by DLN technology alone is on the order of 20 MW for a combined cycle (roughly 13 MW on a simple cycle unit).[17]

Another example of this point is the ABB GT24. It is characterized by a 30:1 compression ratio and 58 percent efficiency in combined cycle. The unit is guaranteed to meet 25 ppmvd of NO_X. The simple cycle version is rated at 183 MW compared to 170 for the GE7FA.

It is not surprising that some compromises were made by ABB, which resulted in greater power and efficiency but slowed progress toward single-digit NO_X emissions. According to ABB, "rather than just concentrating on ever lower NO_X levels, ABB has chosen a total solution that limits pollutants and at the same time increases energy efficiency."[18] A lower compression, lower efficiency version of the ABB GT24 might be capable of 15 ppmvd NO_X or less by DLN technology.

The results during the "new and clean" test of the GE PG7241 at the Polk Power Station (discussed above) are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits. For reference, the values while burning oil were equally good in comparison to the permitted limits for CO and VOC, whereas the NO_X emissions were very close to the permitted value of 42 ppmvd @15% O_2. Visible emissions were 0 percent opacity when firing natural gas or fuel oil.

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.[19]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Pompano Beach project assuming full load. Values for NO_X and CO are corrected to 15% O_2 on a dry volume basis. These emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are specified in the permit.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 10/17 lb/hr – Gas/Fuel Oil (Front-half)
CO	Pipeline Natural Gas Good Combustion	9 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	Pipeline Natural Gas Good Combustion	2 grain of sulfur per 100 ft^3 gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	9 ppmvd – Gas 42 ppmvd – F.O. for 1000 of 3,500 hrs

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are Hot SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- Hot SCR is not commonly required as BACT on simple cycle combustion turbines. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. It is noted that the specification of the fuel oil was 0.15 percent sulfur. This does not imply that hot SCR it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas with 0.05 percent sulfur fuel oil as back-up fuel.
- Hot SCR is required at the simple cycle continuous duty Lakeland McIntosh Unit 5 project if the Westinghouse 501 G unit fails to achieve 9 ppmvd while firing natural gas. Hot SCR was considered cost-effective because the unit will operate continuously and the expected NO_X reduction is from 25 to 9 ppmvd).
- The levelized costs of NO_X removal by Hot SCR for the PBEC were estimated by ENSR at $20,700 per ton assuming 3,500 hours of dual-fuel operation. The estimates are based on emissions controlled to 3.5 and 16 ppmvd @15% O_2 NO_X while burning gas and fuel oil respectively and 9-12 ppmvd of ammonia @15% O_2.
- The levelized costs of NO_X removal by Hot SCR for the DeSoto project were estimated by Golder at $11,350 per ton assuming 3,390 hours of operation on natural gas and a reduction to 3.6 ppmvd on gas and 17 ppmvd on fuel oil. The estimates are based on an ammonia slip of 9 ppmvd for gas and 12 ppmvd for oil.
- The Department does not accept the precise hot SCR cost calculations presented by PBE and considers them on the high end. The costs calculated by Golder for the DeSoto Project are probably more accurate. With the actual performance of the GE 7FA at TECO Polk Power Station with no add-on control (5-8 ppmvd @15%O_2), it is easy to see that hot SCR would not be cost-effective. Hot SCR is rejected as BACT.
- The Department will limit operation of the three units to an average of 3,500 hours per year per unit. No single unit may operate more than 5,000 hours per year to insure that the conclusion regarding cost-effectiveness remains applicable.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out

the possibility of SCONO$_X$. XONON is available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X. This value is equal to that required at the Lakeland continuous duty combustion turbine, which has an alternative hot SCR requirement.
- Typical permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, DeSoto, Virginia Power, Midway, and PBE while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42-ppmvd limit for limited fuel oil firing is typical.
- The gas-based NO_X emission limit of 9 ppmvd will be difficult to maintain over short term averaging times. That is the main reason why some operators cannot provide reasonable assurance they can meet such a low limit by DLN. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion. The permit includes limited periods of data to be excluded from the NO_X CEMS compliance averages due to startup, shutdown and unavoidable malfunction.
- The Department issued permits for the TEC Polk Power, JEA Brandy Branch, and Reliant Osceola Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander, Vandolah, Shady Hills, and DeSoto.
- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[20]
- Based on test results at the JEA Kennedy Plant, it is possible that the NO_X emissions while firing oil from may be reduced from 42 to 30 ppmvd. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.

- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- The fuel oil-based NO_X emissions limit of 42 ppmvd can be maintained over a short-term averaging period by varying the amount of water injected. The Department has determined that a 3-hour averaging time is appropriate.
- The Department's overall BACT determination is equivalent to approximately 0.4 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- The applicant estimates VOC emissions of 1.4 ppmvd while firing gas and 1.4 ppmvd while burning fuel oil. The Department will set the limits at 2.8 ppmvd because at this concentration, the project will still not trigger PSD or a requirement for a BACT determination.
- The Department will set CO limits achievable by good combustion at full load as 9 ppmvd @15% O_2 (gas) and 20 ppmvd (oil). These values are in the lower range of values from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- PBE estimated levelized costs for CO catalyst control at $13,200. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- Golder evaluated the use of oxidation catalyst for the DeSoto project with 90 percent control efficiency. Golder estimated levelized costs for CO catalyst control at $7,500 per ton.
- The cost of CO control by oxidation catalyst is probably closer to the Golder estimate based on reducing *permitted* CO emissions. However in view of the performance of GE 7FA units without add-on control (~1 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will not set a continuous CO limit reflecting the "new and clean test" because GE will not guarantee it. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- There is no benefit in penalizing the applicant or with a lower limit at this time just because the performance at another site was far better than guaranteed or expected.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limits for PM_{10} will be set at 10 pounds per hour during gas operation and 17 pounds per hour while operating on fuel oil. These values are based on front-half catch only.

- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power, DeSoto Power, Vandolah, Shady Hills and quite a number of combined cycle projects.

POLLUTANT	COMPLIANCE PROCEDURE
PM/PM_{10} (Visible Emissions)	Conduct initial, concurrent Method 5 and 9 tests and annual Method 9 tests. Thereafter, fuel specifications and CO/VE limits serve as surrogate limits.
CO	Conduct initial and annual Method 10 tests.
NO_X (Initial)	Conduct initial Method 20 (or 7E) tests.
NO_X (Continuous)	Continuous compliance demonstrated by data collected from NO_X CEMS and diluent monitors (O_2 or CO_2). 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. Pursuant to Rule 62-210.700 F.A.C., up to 2 hourly averages in a 24-hour block may be excluded due to startups and shutdowns. Up to 2 hourly averages in a 24-hour block may be excluded due to unavoidable malfunction. A separate compliance determination is conducted at the end of each operating day, which is calculated from the arithmetic average of all valid hourly emission rates. May use data collected during RATA if performed at capacity.
SO_2 and SAM	Maintain records of fuel sampling and analysis with appropriate ASTM Methods.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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:

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

Date

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date

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APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Pompano Beach Energy Center
PSD-FL-304 and 0112515-001-AC
Broward County, Florida

BACKGROUND

The applicant, Pompano Beach Energy, L.L.C. (PBE, an affiliate of Enron North America), proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Pompano Beach Energy Center (PBEC) in Broward County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 80-foot stacks. PBE proposes to operate these units up to 3,500 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated March 7, 2001, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on October 23, 2000 (revised December 15) and included a proposed BACT proposal prepared by the applicant's consultant, ENSR.

PREPARED BY:

A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	9 ppmvd @ 15% O_2 (gas)[1] 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	9 ppmvd (gas, baseload) 20 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, 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 PBE is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the PBEC.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple cycle turbines. Two (Carson and McClellan) were permitted in ozone non-attainment areas and two (Lakeland and PREPA) were permitted as continuous duty projects. The proposed PBEC is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 11/00. 1000 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 2/2001. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 2/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Tenaska Heard, GA	960	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
RockGen Cristiana, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous
SC = Simple Cycle
INT = Intermittent

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR

FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

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.

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Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Pompano Beach project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 1000 hours per year (per CT).

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 each turbine of the Pompano Beach Project. The proposed NO_X controls will reduce these emissions significantly.

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

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 incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design 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. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X.

The 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 may occur 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.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Tests at the JEA[2] Kennedy Plant indicated that 30 ppmvd is achievable on a short-term basis.

Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[3] where water is scarce, but the Department has no information on the results. Mitsubishi (who also make a 501F) is developing a dual-fuel premixed 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.[4] The details are not available in English.

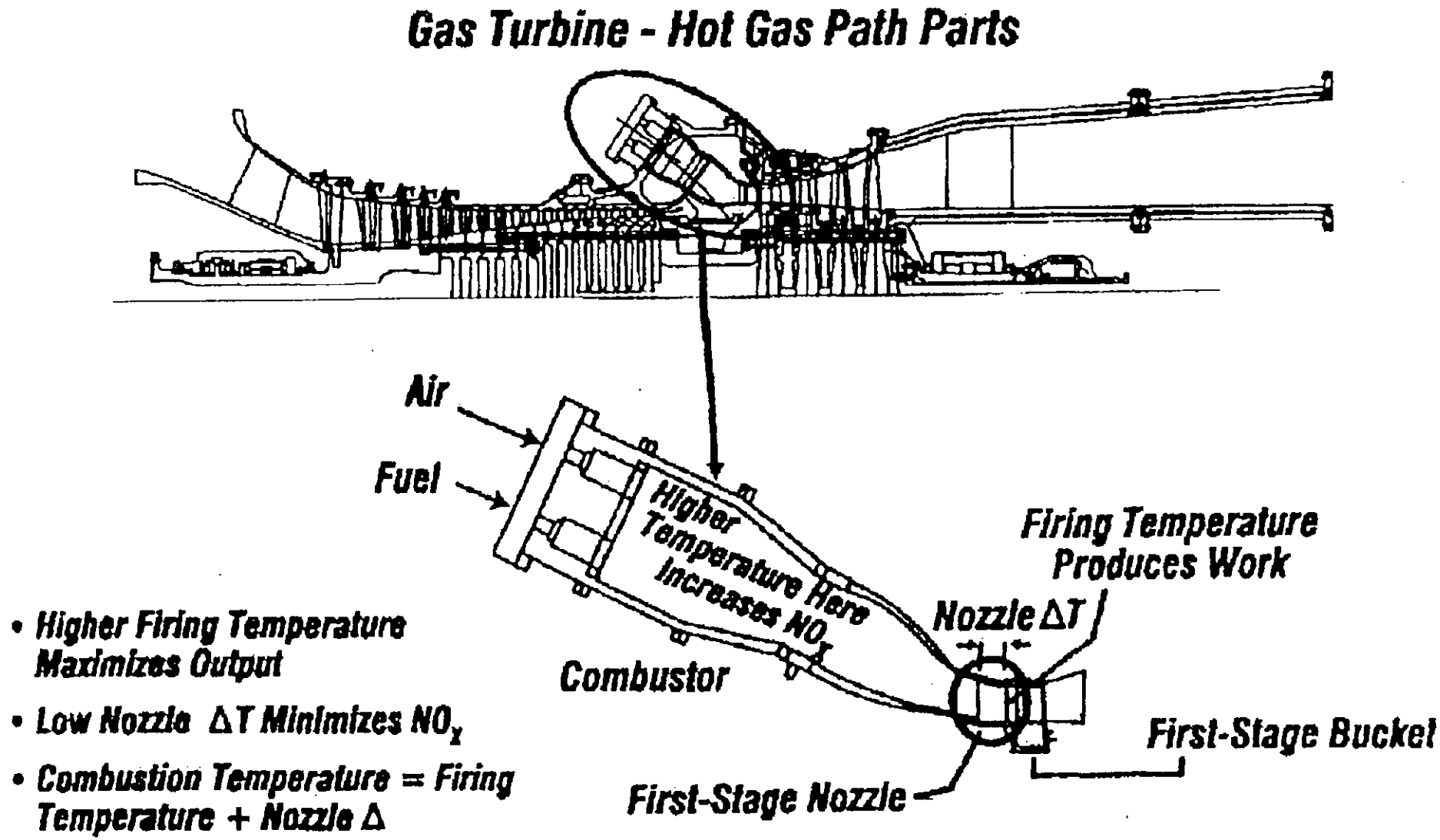

Figure 1 – Relation Between Flame Temperature and Firing Temperature

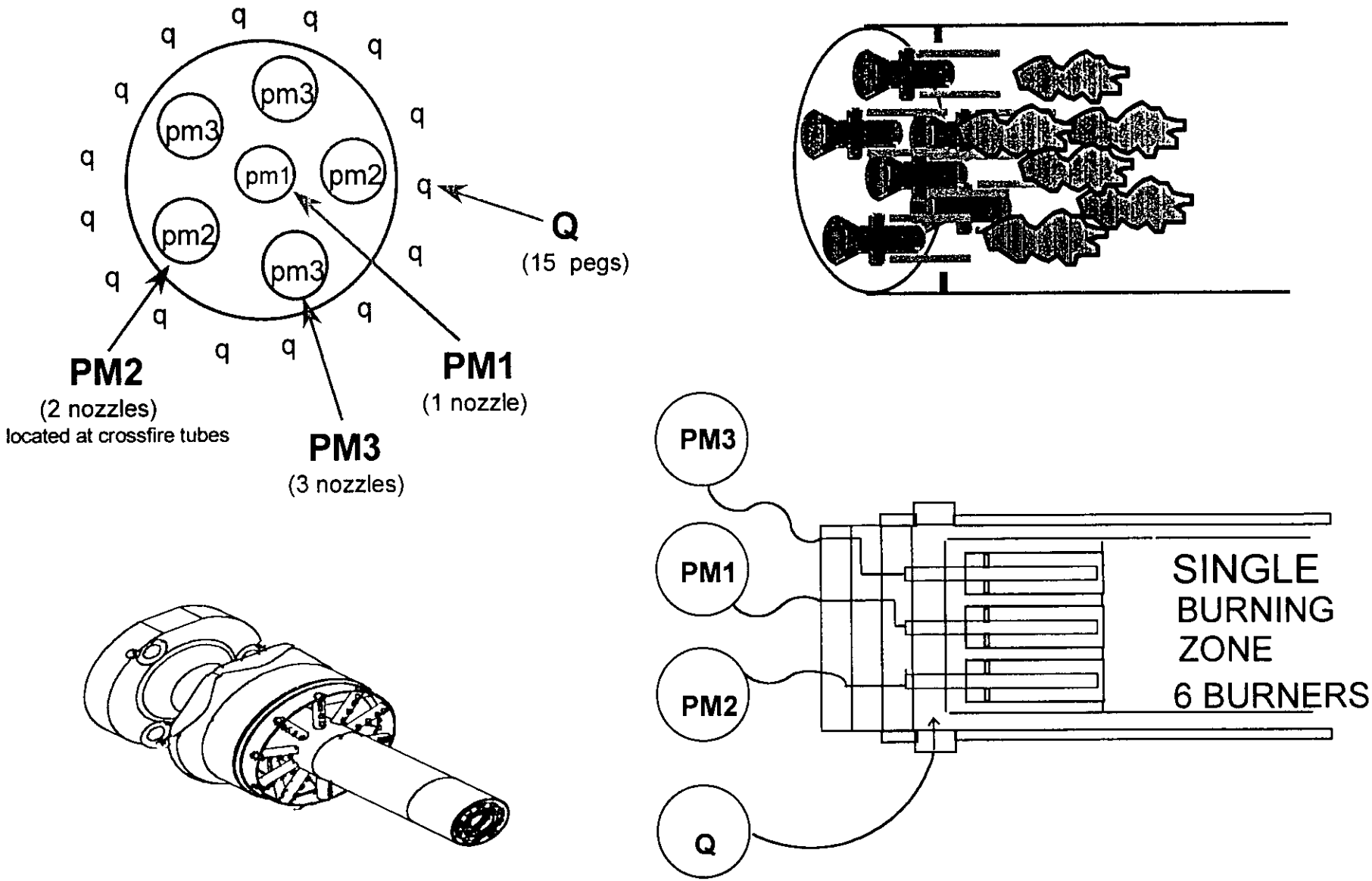

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

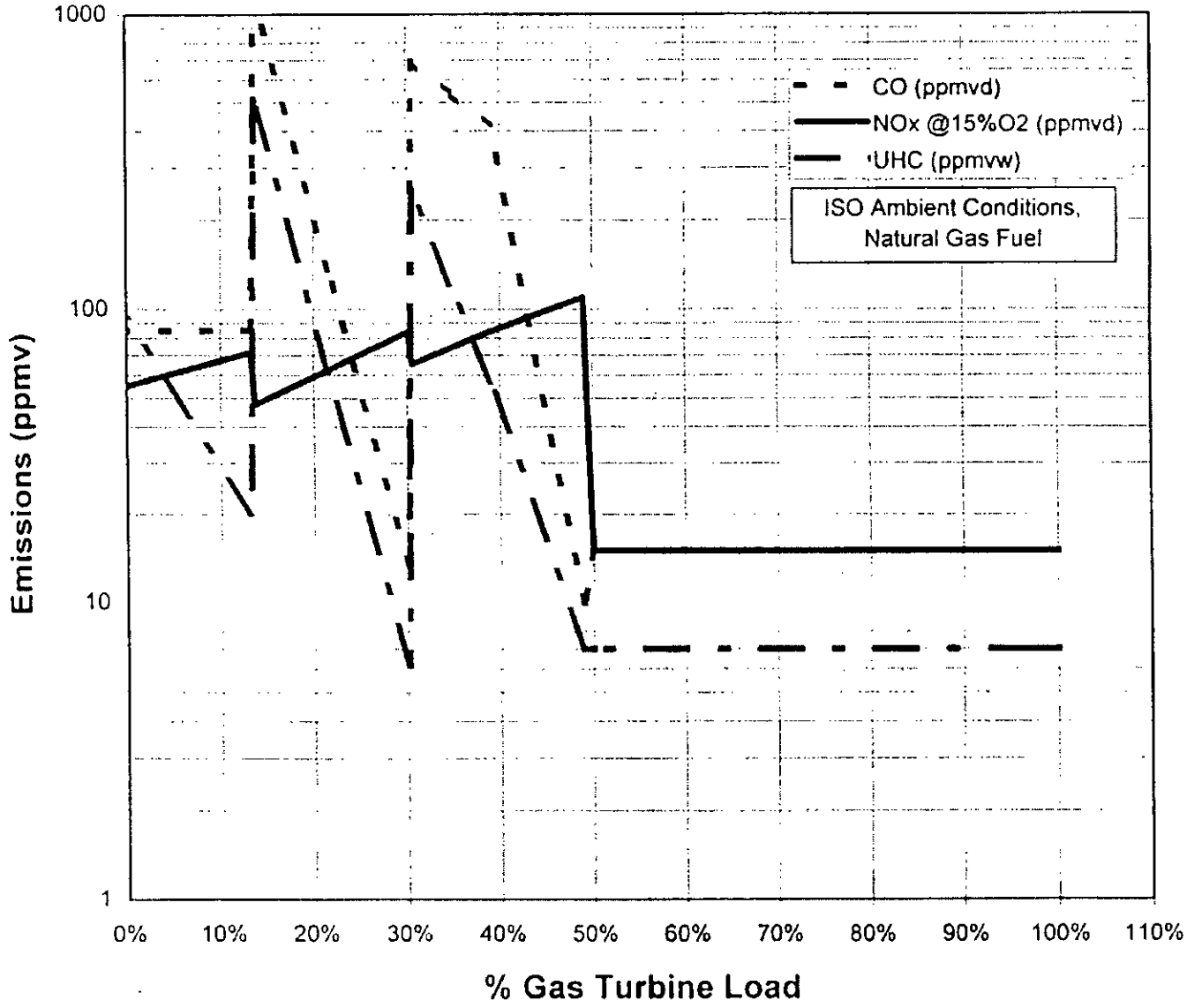

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

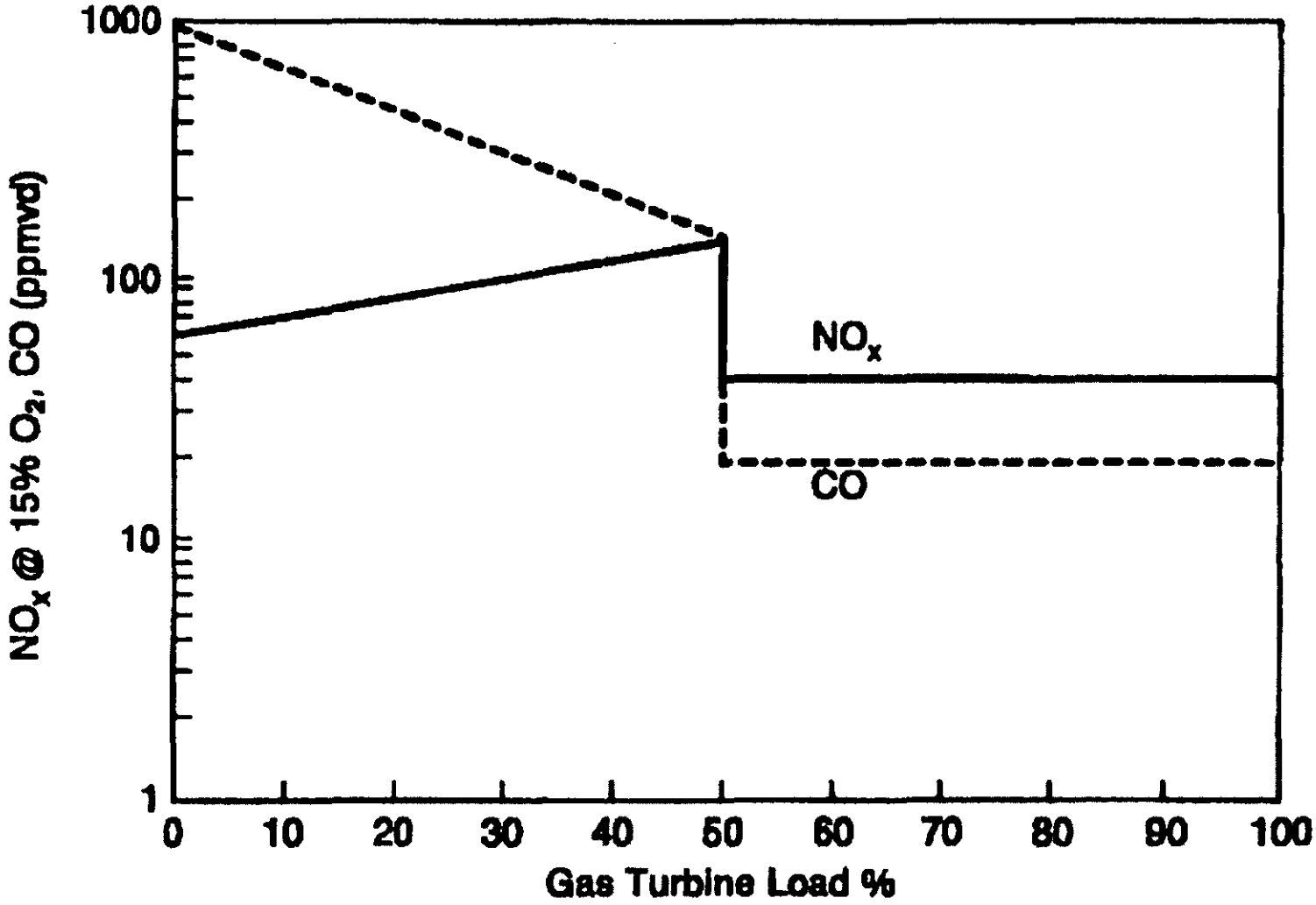

Figure 4 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

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 5 from an EPRI report.[5] 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 5.

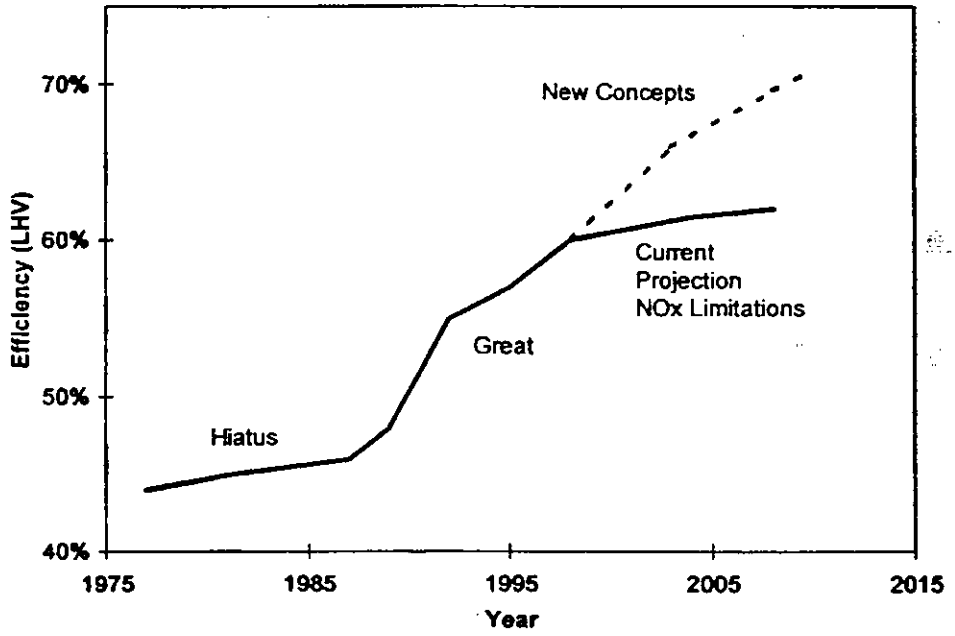

Figure 5 – Efficiency Increases in Combustion Turbines

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 (G or H Class technology) than the units planned by PBE. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. 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 instead of air cooling.

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 above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[6] 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, for example, 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™.[7] 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.[8] The project will enter commercial operation by the summer of 2001. However actual installation of XONON™ 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 Combustion

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.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

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 (Paynes Creek) project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority,[9] FPC, TECO, and Competitive Power Ventures will install SCR on combined cycle projects to achieve 3.5 ppmvd. Limits as low as 2 ppmvd NO_X have been specified using SCR on combined cycle F Class projects in various parts of the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) 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 Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

$SCONO_X$™ is a catalytic add-on technology 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.[10]

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.[11] The overall project includes several more 250 MW blocks with SCR for control.[12] 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. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [13] 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.

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."[14]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

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 190 TPY of SO_2 and 29 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf, but high enough to require a BACT determination.

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 its use is proposed for only 1000 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. Total annual emissions of PM_{10} for the project are expected to be approximately 119 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones 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 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[15]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 9 and 30 ppmvd for gas and oil respectively at baseload proposed in PBE's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by PBE for this project are 1.4 ppmvw for gas and fuel oil firing at baseload. These limits are sufficient to keep annual emissions of VOC below the 40 TPY threshold and a BACT determination is not required. 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]

BACKGROUND ON PROPOSED GAS TURBINE

PBE plans to install three nominal 170 MW General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

Typically, companies obtain a guarantee from GE to achieve 9 ppmvd NO_X during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation. With the frequent start-ups and shutdowns of the units, some applicants are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, some of them agreed to a "new and clean" limit of 9 ppmvd but requested a continuing BACT limit of 10.5 ppmvd.

As detailed in the table above, the Department has issued quite a number of permits for simple cycle GE 7FA requiring achievement of 9-10.5 ppmvd without the requirement of any additional control equipment. The ones with limits of 9 ppmvd are allowed to operate for as many as 1000 hours per year on back-up fuel oil whereas the ones permitted at 10.5 ppmvd are allowed only 750 hours per year of fuel oil. A smaller GE unit known as the 7EA can routinely achieve 9 ppmvd NO_X or lower based on numerous installations in Florida and elsewhere. The 7EA has a lower flame temperature, compression ratio, and power rating (85 versus 170 MW) than the 7FA.

The ability to meet a NO_X emission limit of 9 ppmvd by DLN technology involves a substantial efficiency and energy penalty as previously discussed. For example, the 7FA is characterized by a 15.5:1 compression ratio, a 2400 °F firing temperature, 56 percent efficiency, and produces 263 MW in combined cycle. On the other hand, GE offers a more efficient F-Class model known as the 7FB, but guarantees a NO_X limit of 25 ppmvd by DLN.

The 7FB is characterized by an 18.5:1 compression ratio, a 2500 °F firing temperature, 57.3 percent efficiency, and produces 280 MW in combined cycle. The clear implication is that the

power penalty to reduce NO_X from 25 to 9 ppmvd by DLN technology alone is on the order of 20 MW for a combined cycle (roughly 13 MW on a simple cycle unit).[17]

Another example of this point is the ABB GT24. It is characterized by a 30:1 compression ratio and 58 percent efficiency in combined cycle. The unit is guaranteed to meet 25 ppmvd of NO_X. The simple cycle version is rated at 183 MW compared to 170 for the GE7FA.

It is not surprising that some compromises were made by ABB, which resulted in greater power and efficiency but slowed progress toward single-digit NO_X emissions. According to ABB, "rather than just concentrating on ever lower NO_X levels, ABB has chosen a total solution that limits pollutants and at the same time increases energy efficiency."[18] A lower compression, lower efficiency version of the ABB GT24 might be capable of 15 ppmvd NO_X or less by DLN technology.

The results during the "new and clean" test of the GE PG7241 at the Polk Power Station (discussed above) are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits. For reference, the values while burning oil were equally good in comparison to the permitted limits for CO and VOC, whereas the NO_X emissions were very close to the permitted value of 42 ppmvd @15% O_2. Visible emissions were 0 percent opacity when firing natural gas or fuel oil.

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.[19]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Pompano Beach project assuming full load. Values for NO_X and CO are corrected to 15% O_2 on a dry volume basis. These emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are specified in the permit.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 10/17 lb/hr – Gas/Fuel Oil (Front-half)
CO	Pipeline Natural Gas Good Combustion	9 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	Pipeline Natural Gas Good Combustion	2 grain of sulfur per 100 ft^3 gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	9 ppmvd – Gas 42 ppmvd – F.O. for 1000 of 3,500 hrs

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are Hot SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- Hot SCR is not commonly required as BACT on simple cycle combustion turbines. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. It is noted that the specification of the fuel oil was 0.15 percent sulfur. This does not imply that hot SCR it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas with 0.05 percent sulfur fuel oil as back-up fuel.
- Hot SCR is required at the simple cycle continuous duty Lakeland McIntosh Unit 5 project if the Westinghouse 501 G unit fails to achieve 9 ppmvd while firing natural gas. Hot SCR was considered cost-effective because the unit will operate continuously and the expected NO_X reduction is from 25 to 9 ppmvd).
- The levelized costs of NO_X removal by Hot SCR for the PBEC were estimated by ENSR at $20,700 per ton assuming 3,500 hours of dual-fuel operation. The estimates are based on emissions controlled to 3.5 and 16 ppmvd @15% O_2 NO_X while burning gas and fuel oil respectively and 9-12 ppmvd of ammonia @15% O_2.
- The levelized costs of NO_X removal by Hot SCR for the DeSoto project were estimated by Golder at $11,350 per ton assuming 3,390 hours of operation on natural gas and a reduction to 3.6 ppmvd on gas and 17 ppmvd on fuel oil. The estimates are based on an ammonia slip of 9 ppmvd for gas and 12 ppmvd for oil.
- The Department does not accept the precise hot SCR cost calculations presented by PBE and considers them on the high end. The costs calculated by Golder for the DeSoto Project are probably more accurate. With the actual performance of the GE 7FA at TECO Polk Power Station with no add-on control (5-8 ppmvd @15%O_2), it is easy to see that hot SCR would not be cost-effective. Hot SCR is rejected as BACT.
- The Department will limit operation of the three units to an average of 3,500 hours per year per unit. No single unit may operate more than 5,000 hours per year to insure that the conclusion regarding cost-effectiveness remains applicable.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out

the possibility of SCONO$_X$. XONON is available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X. This value is equal to that required at the Lakeland continuous duty combustion turbine, which has an alternative hot SCR requirement.
- Typical permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, DeSoto, Virginia Power, Midway, and PBE while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42-ppmvd limit for limited fuel oil firing is typical.
- The gas-based NO_X emission limit of 9 ppmvd will be difficult to maintain over short term averaging times. That is the main reason why some operators cannot provide reasonable assurance they can meet such a low limit by DLN. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion. The permit includes limited periods of data to be excluded from the NO_X CEMS compliance averages due to startup, shutdown and unavoidable malfunction.
- The Department issued permits for the TEC Polk Power, JEA Brandy Branch, and Reliant Osceola Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander, Vandolah, Shady Hills, and DeSoto.
- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[20]
- Based on test results at the JEA Kennedy Plant, it is possible that the NO_X emissions while firing oil from may be reduced from 42 to 30 ppmvd. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.

- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- The fuel oil-based NO_X emissions limit of 42 ppmvd can be maintained over a short-term averaging period by varying the amount of water injected. The Department has determined that a 3-hour averaging time is appropriate.
- The Department's overall BACT determination is equivalent to approximately 0.4 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- The applicant estimates VOC emissions of 1.4 ppmvd while firing gas and 1.4 ppmvd while burning fuel oil. The Department will set the limits at 2.8 ppmvd because at this concentration, the project will still not trigger PSD or a requirement for a BACT determination.
- The Department will set CO limits achievable by good combustion at full load as 9 ppmvd @15% O_2 (gas) and 20 ppmvd (oil). These values are in the lower range of values from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- PBE estimated levelized costs for CO catalyst control at $13,200. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- Golder evaluated the use of oxidation catalyst for the DeSoto project with 90 percent control efficiency. Golder estimated levelized costs for CO catalyst control at $7,500 per ton.
- The cost of CO control by oxidation catalyst is probably closer to the Golder estimate based on reducing *permitted* CO emissions. However in view of the performance of GE 7FA units without add-on control (~1 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will not set a continuous CO limit reflecting the "new and clean test" because GE will not guarantee it. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- There is no benefit in penalizing the applicant or with a lower limit at this time just because the performance at another site was far better than guaranteed or expected.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limits for PM_{10} will be set at 10 pounds per hour during gas operation and 17 pounds per hour while operating on fuel oil. These values are based on front-half catch only.

- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power, DeSoto Power, Vandolah, Shady Hills and quite a number of combined cycle projects.

POLLUTANT	COMPLIANCE PROCEDURE
PM/PM_{10} (Visible Emissions)	Conduct initial, concurrent Method 5 and 9 tests and annual Method 9 tests. Thereafter, fuel specifications and CO/VE limits serve as surrogate limits.
CO	Conduct initial and annual Method 10 tests.
NO_X (Initial)	Conduct initial Method 20 (or 7E) tests.
NO_X (Continuous)	Continuous compliance demonstrated by data collected from NO_X CEMS and diluent monitors (O_2 or CO_2). 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. Pursuant to Rule 62-210.700 F.A.C., up to 2 hourly averages in a 24-hour block may be excluded due to startups and shutdowns. Up to 2 hourly averages in a 24-hour block may be excluded due to unavoidable malfunction. A separate compliance determination is conducted at the end of each operating day, which is calculated from the arithmetic average of all valid hourly emission rates. May use data collected during RATA if performed at capacity.
SO_2 and SAM	Maintain records of fuel sampling and analysis with appropriate ASTM Methods.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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:

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

Date

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date

References

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

[20] Letter. Linero, A. A., FDEP to Forry, J. and Chalfin, J. General Electric. NO_X emissions control while firing fuel oil in Simple Cycle Units. October 12, 1999.

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 any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

APPENDIX GG
NSPS Subpart GG Requirements for Gas Turbines

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

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

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

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NOx = emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

Po = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

Florida Department of Environmental Protection

Memorandum

TO: Clair Fancy

FROM: Al Linero 3/2

DATE: March 2, 2001

SUBJECT: Pompano Beach Energy Center
Three 170 MW Combustion Turbines
DEP File No. 0112515-001-AC (PSD-FL-304)

Attached is the public notice package for construction of a 510 MW power plant in Pompano Beach. The plant will consist of three dual-fuel, intermittent duty, simple cycle, 170 MW GE 7FA combustion turbines. Ancillary facilities include inlet air chillers, four wet mechanical draft cooling towers, a gas-fired heater, two fuel oil storage tanks, and three 80-foot stacks.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6) combustion. The applicant proposed an NO_X emission limit of 9 ppmvd @15% O_2. The facility may operate up to 3,500 hour per year per unit. Use of fuel oil will be allowed up to 1000 hour/year/unit during which a NO_X limit of 42 ppmvd applies. This represents a reduction from 1,500 hours /year/unit requested in the original application.

Enron North America (the parent of Pompano Beach Energy L.L.C.) and other applicants claim they cannot get a guarantee from the manufacturer less than 42 ppmvd when firing fuel oil. We determined that high temperature SCR is not cost-effective for this project. To discourage use of fuel oil, we included two provisions. The first requires a report outlining the possibilities for NO_X reductions when firing fuel oil. This requirement is triggered when the facility actually uses fuel oil more than 500 hours per unit during a 12-month period. The second provision limits total operation of the facility by 2 hours for every hour of fuel oil firing beyond 250 hours per unit during a 12-month period.

Based on some very recent data we reviewed from a simple cycle unit at JEA, we believe they will be able to reduce NO_X emissions when firing fuel oil. The "2 for 1" provision will limit operation of the facility to 2000 hours/year/unit if the facility uses fuel oil for 1000 hours/year/unit.

Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, the design of the GE unit. The project has an insignificant impact in Class II areas and is significant in the Class I Everglades National Park only for SO_2. However, the project will not cause or contribute to a violation of any Class I or Class II National Ambient Air Quality Standard or Increment.

The National Park Service reviewed the modeling performed by the applicant, including regional haze in the Class I Everglades National Park. They advised that they have no adverse comments regarding this project and said that no further modeling is necessarily to provide their input prior to issuance of our final decision. We typically receive input from EPA after distribution of an Intent to Issue. This project is almost identical to the Enron Midway Project. Basically, we incorporated most of EPA's suggestions on Midway into the Pompano Project. We can still expect some additional comments from EPA.

We will advise the affected cities, county commissioners, and legislators as soon as an Intent is signed. The Broward County Department of Planning and Environmental Protection reviewed the application, updates in response to requirements in their local ordinance, and various drafts of this package. They did not indicate any opposition to this project but advised of the public controversy associated with it.

A public meeting has been scheduled in Pompano Beach for March 26. We mentioned this in the enclosed public notice. We also provided a draft notice in the appropriate format to OGC for review and submittal to the FAW.

Today (March 2) is day 72. I recommend your approval of the attached Intent to Issue.

AAL/al

Attachments

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 0112515-001-AC (PSD-FL-304)

Pompano Beach Energy, L.L.C.
Pompano Beach Energy Center
Broward County

Project type:

Project is construction of three 170-megawatt GE PG7241FA gas and oil-fired simple cycle combustion turbine-electrical generators with 80-foot stacks, inlet air chillers, two fuel oil storage tanks, four wet mechanical draft cooling towers, a gas heater, and ancillary equipment. Units will operate maximum of 3,500 hours per year per unit of which 1000 hours per year per unit may be on No. 2 distillate fuel oil. The facility will be further limited by two hours of operation for every hour of operation that fuel oil is used beyond 250 hours per unit over a 12-month period. Therefore if fuel oil is consumed for 1000 hours per unit during a 12-month period, then total facility operation is restricted to 2000 hours per unit.

The units must meet the manufacturer's "new and clean" nitrogen oxides performance guarantee of 9 parts per million by volume, dry, at 15% oxygen (ppmvd) while burning natural gas. The continuous (24-hour) BACT NO_X limits are 9 ppmvd when operating on natural gas and 42 ppmvd by wet injection when burning fuel oil. A report outlining the possibilities for NO_X reduction must be prepared if the facility uses fuel oil for more than 500 hours per unit during a 12-month period. Other pollutants, including particulate matter (PM/PM_{10}), carbon monoxide, volatile organic compounds, sulfur dioxide, and sulfuric acid mist will be controlled by good combustion and use of clean fuels.

Projected impacts from the proposed project emissions are all less than the applicable significant impact limits (SILs) corresponding to the nearby Class II areas. Except for SO_2, projected impacts are less than the applicable SILs corresponding to the Class I Everglades National Park. The project will not cause or contribute to a violation of any National Ambient Air Quality Standard or Increment. The National Park Service advised us that they have no adverse comments regarding this project.

I HEREBY CERTIFY *that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

A A. Linero, P.E. — Date: 3/2/01
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
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Tallahassee, Florida 32301
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3/2