

THE PALM BEACH POST

Published Daily and Sunday
West Palm Beach, Palm Beach County, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA

COUNTY OF PALM BEACH

Before the undersigned authority personally appeared Tyler Dixon, who on oath says that she is Classified Advertising Manager, Inside Sales of The Palm Beach Post, a daily and Sunday newspaper published at West Palm Beach in Palm Beach County, Florida; that the attached copy of advertising, being Notice in the matter of Ref No. 0009640300 Intent to issue air construction permit in the Court, was published in said newspaper in the issues of September 14, 2001.

Affiant further says that the said The Post is a newspaper published at West Palm Beach, in said Palm Beach County, Florida, and that the said newspaper has heretofore been continuously published in said Palm Beach County, Florida, daily and Sunday and has been entered as second class mail matter at the post office in West Palm Beach, in said Palm Beach County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she/he has neither paid nor promised any person, firm or corporation any discount rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before this 14th day of September, A.D. 2001

Personally known XX or Produced Identification
Type of Identification Produced _____



NO. 351967 PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0990594-001-AC (PSD-FL-317)
El Paso Balke Glode Energy Center
Palm Beach 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 El Paso Balke Glode Energy Center. The permit is to construct a proposed 400 megawatt (MW) natural gas-fired power plant (0.33 Miles East of SR 80, South of Curlew Road in Balke Glode, Palm Beach County, A Best Available Control Technology (BACT) assessment was required for sulfur dioxide (SO₂), particulate matter (PM₁₀/PM_{2.5}), 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 El Paso Balke Glode Energy Center, 1001 Louisiana Street, Houston, Texas 77002.

El Paso proposes to construct three combined 175-MW General Electric PG7211A natural gas-fired combined cycle electrical generators. Two of the units will operate in simple cycle mode and intermittent duty. The other unit will operate in combined cycle mode and will include an unfired heat recovery steam generator and a separate steam-electric generator.

Additional equipment includes three 135-foot stacks, a three-cell mechanical draft fresh water cooling tower, a 2,600-horsepower fire emergency diesel-fired electrical generator, a 250-hp emergency diesel-fired fire water pump, a natural gas fuel heater, an aqueous ammonia storage tank, and raw and demineralized water storage tanks.

NO_x emissions will be controlled by Dry Low NO_x (DLN-2) combustors. The two simple cycle units must meet an emission limit of 9 parts per million by volume, dry at 15 percent oxygen (ppmv @ 15% O₂). NO_x emissions on the combined cycle unit will be further controlled by selective catalytic reduction (SCR) to achieve 2.5 ppbvd. Emissions of CO will be controlled to 6 ppmvd @ 15% O₂ except during periods of power augmentation when the limit for the combined cycle unit will be 12 ppmvd @ 15% O₂.

Emissions of PM₁₀/PM_{2.5}, SO₂, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAPs) will be controlled by wet scrubbers and use of inherently clean piping quality natural gas. Ammonia emissions (HAPs) generated due to NO_x control on the combined cycle unit will be limited to 5 ppmvd.

The combined maximum emissions from the three units in tons per year are summarized below. These include emissions from the emergency diesel generator.

PSD Significant Emission Rate	PSD Significant Emission Rate
PM ₁₀ /PM _{2.5} (filterable plus condensable)	181
NO _x	25773
CO	100
SO ₂	40
YOC	40
SO ₂ (HAP)	69
Sulfuric Acid Mist	7

Maximum predicted air quality impacts due to emissions from the El Paso project are less than the applicable PSD Class I significant impact levels, with the exception of 24-hour average PM₁₀. Therefore, multi-source modeling was required for PM₁₀ under PSD Class I. PSD Class I significant impact levels for PM₁₀ are 175 µg/m³ for all sources (El Paso Project) and 277 µg/m³ for all sources (El Paso Project).

A CALPUFF modeling analysis for the El Paso project was submitted by the applicant to the National Park Service (NPS). On the basis of the NPS analysis, the Department is not required to consider the potential for impacts from the proposed facility will have any significant impacts on resources of the Everglades National Park.

Based on the required analysis, 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 project is not subject to Section 403.501-518, F.S., Florida Electrical Power Plant Siting Act, based on information regarding gross electrical power generated from the steam cycle submitted by the applicant and reviewed by the Department.

The Department will issue the PSD permit in accordance with the conditions of the DRAFT Permit, unless a request received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit action for a period of 30 days from the date of publication of the Public Notice of Intent to issue an Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2400 Blair Stone Road, Mail Station #5503, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public review.

The Department will issue the permit unless a petition for a hearing is filed with the Department within 14 days of the date of publication of this notice. A petitioner shall mail a copy of the petition to the applicant or 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 28-104.205 of the Florida Administrative Code.

A petition that disputes the material facts upon 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; (b) the name, address, and telephone number of the petitioner; (c) 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 proceedings; and an explanation of how the petitioner's substantial interests will be affected by the agency's proposed action; (d) A statement of how and when petitioner received notice of the agency action or proposed action; (e) A statement of disputed issues of material fact; (f) If there are none, the petition must so indicate; (g) A concise statement of the ultimate facts alleged; (h) The specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (i) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (j) 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 28-104.301.

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:
Department of Environmental Protection (El Paso Balke Glode Energy Center Health Department Bureau of Air Regulation)
Southwest District Office: 901 Eureka Street, West Palm Beach, Florida 33411
North District Office: 400 North Congress Avenue, West Palm Beach, Florida 33411
Telephone: 561/581-6400
Fax: 561/681-6753

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, Bureau of Air Regulation, Section 111 South Congress 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://www.dep.state.fl.us/air/permits/0990594-001-AC/0990594-001-AC.htm>.

PUBLISH: September 14, 2001

SENDER: COMPLETE THIS SECTION	COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 	A. Received by (Please Print Clearly)	B. Date of Delivery 9/11
<p>1. Article Addressed to:</p> <p>Mr. William Mack, Sr. Managing Director El Paso Merchant Energy Co. 1001 Louisiana Street Houston, TX 77002</p>	<p>C. Signature [Signature] 9/11</p> <p><input type="checkbox"/> Agent <input type="checkbox"/> Addressee</p>	
<p>2. Article Number (Copy from service label)</p> <p>7000 0600 0026 4129 8054</p>	<p>D. Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below: <input type="checkbox"/> No</p>	
<p>PS Form 3811, July 1999</p>	<p>3. Service Type</p> <p><input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C.O.D.</p> <p>4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes</p> <p>Domestic Return Receipt</p> <p>102595-99-M-1789</p>	

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

7000 0600 0026 4129 8054

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

Recipient's Name (Please Print Clearly) (to be completed by mailer)
 William Mack, Sr.
 Street, Apt. No.; or PO Box No.
 1001 Louisiana Street
 City, State, ZIP+4
 Houston, TX 77002

PS Form 3800, February 2000
See Reverse for Instructions



Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

September 7, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William Mack Sr., Managing Director
El Paso Merchant Energy Company
1001 Louisiana Street
Houston, Texas 77002

Re: DEP File No. 0990594-001-AC (PSD-FL-317)
Belle Glade Energy Center
600-Megawatt Power Plant

Dear Mr. Mack:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Belle Glade Energy Center to be located in Palm Beach 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. If you have any questions please call Ms. Teresa Heron at 850/921-9529.

Sincerely,

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

CHF/al

Enclosures

"More Protection, Less Process"

Printed on recycled paper.

In the Matter of an
Application for Permit by:

Mr. William Mack, Sr., Managing Director
El Paso Merchant Energy Company
1001 Louisiana Street
Houston, Texas 77002

DEP File No. 0990594-001-AC (PSD-317)
Belle Glade Energy Center
Palm Beach 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, El Paso Merchant Energy Company, applied on March 28, 2001 (complete June 27, 2001) to the Department for an air construction permit to construct a 600-megawatt natural gas-fueled combustion turbine power plant for the Belle Glade Energy Center to be located in Belle Glade, Palm Beach 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 and requests for public meetings 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

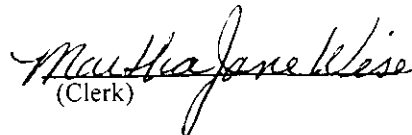
The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9/17/01 to the person(s) listed:

William Mack, El Paso*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Tom Davis, P.E., ECT

Jim Stormer, PBCHD
Krish Ravishankar, El Paso
Mayor, City of Belle Glade*
Chair, Palm Beach County BCC*

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.

 9/17/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0990594-001-AC (PSD-FL-317)

El Paso Belle Glade Energy Center
Palm Beach 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 El Paso Merchant Energy Company. The permit is to construct a nominal 600-megawatt (MW) natural gas-fueled power plant 0.33 Miles East of SR 80, South of Curlee Road in Belle Glade, Palm Beach County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO₂), particulate matter (PM/PM₁₀), 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 El Paso Merchant Energy Company, 1001 Louisiana Street, Houston, Texas 77002.

El Paso proposes to construct three nominal 175-MW General Electric PG7241FA natural gas-fired combustion turbine-electrical generators. Two of the units will operate in simple cycle mode and intermittent duty. The other unit will operate in combined cycle mode and will include an unfired heat recovery steam generator and a separate steam-electrical generator.

Additional equipment includes three 135-foot stacks, a five-cell mechanical draft fresh water cooling tower, a 2,600-horsepower (hp) emergency diesel-fired electrical generator, a 250-hp emergency diesel-fired fire water pump, a natural gas fired heater, an aqueous ammonia storage tank, and raw and demineralized water storage tanks.

NO_x emissions will be controlled by Dry Low NO_x (DLN-2.6) combustors. The two simple cycle units must meet an emission limit of 9 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O₂). NO_x emissions from the combined cycle unit will be further controlled by selective catalytic reduction (SCR) to achieve 2.5 ppmvd at 15% O₂. Emissions of CO will be controlled to 8 ppmvd @15% O₂ except during periods of power augmentation when the limit for the combined cycle unit will be 12 ppmvd @15% O₂.

Emissions of PM/PM₁₀, SO₂, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas. Ammonia emissions (NH₃) generated due to NO_x control on the combined cycle unit will be limited to 5 ppmvd.

The combined maximum emissions from the three units in tons per year are summarized below. These include the minor emissions from the emergency diesel engines and the cooling towers.

<u>Pollutant</u>	<u>Maximum Potential Emissions</u>	<u>PSD Significant Emission Rate</u>
PM/PM ₁₀ (filterable plus condensable)	181	25/15
CO	349	100
NO _x	365	40
VOC	29	40
SO ₂	69	40
Sulfuric Acid Mist	10	7

Maximum predicted air quality impacts due to emissions from the El Paso project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour average PM₁₀. Therefore, multi-source modeling was required for PM₁₀. The maximum predicted PSD Class II PM₁₀ increments consumed in Palm Beach County by increment consuming sources (since 1975-77) within 51 km of the project, will be as follows:

<u>Averaging Time</u>	<u>Increment Consumed All Sources/El Paso Project (ug PM₁₀/m³)</u>	<u>Allowable Increment All Sources (ug PM₁₀/m³)</u>	<u>Percent Increment Consumed All Sources/El Paso Project (percent)</u>
24-hour	14/4	30	47/13

Maximum predicted air quality impacts due to emissions from the El Paso project are less than the applicable PSD Class I significant impact levels.

A CALPUFF modeling analysis for the El Paso project was submitted by the applicant to the National Park Service (NPS). On the basis of the submittal, NPS advised the Department that it "does not anticipate that the emissions from the proposed facility will have any significant impacts on resources at the Everglades National Park."

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.

Notice for Newspaper

The project is not subject to Section 403.501-518, F.S., Florida Electrical Power Plant Siting Act, based on information regarding gross electrical power generated from the steam cycle submitted by the applicant and reviewed by the Department.

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 and requests for a public meeting 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. 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.

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Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

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

Palm Beach County Health Department
901 Evernia Street
Post Office Box 29
West Palm Beach, Florida 33402-0029
Telephone: 561/355-30760
Fax: 561/355-2442

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>

Notice for Newspaper

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

El Paso Belle Glade Energy Center

600-Megawatt Electrical Power Plant

Palm Beach County

DEP File No. 0990594-001-AC (PSD-FL-317)

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

September 7, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

El Paso Merchant Energy Company
 1001 Louisiana Street
 Houston, Texas 77002

Authorized Representative: *William Mack, Sr., Managing Director*

1.2 Reviewing and Process Schedule

03-28-01: Date of Receipt of Application
 06-27-01: Application Complete
 09-07-01: Distributed Intent to Issue

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The El Paso Belle Glades Energy Center will be located in Palm Beach, near the Southeast coast of Florida. The location is approximately 105 kilometers North-northeast of the Everglades National Park. The proposed site is 0.33 Mile east of SR 80, South of Curlee Road in Belle Glades. The UTM coordinates for this facility are Zone 17; 533.5 km East; 2954.1 km North.

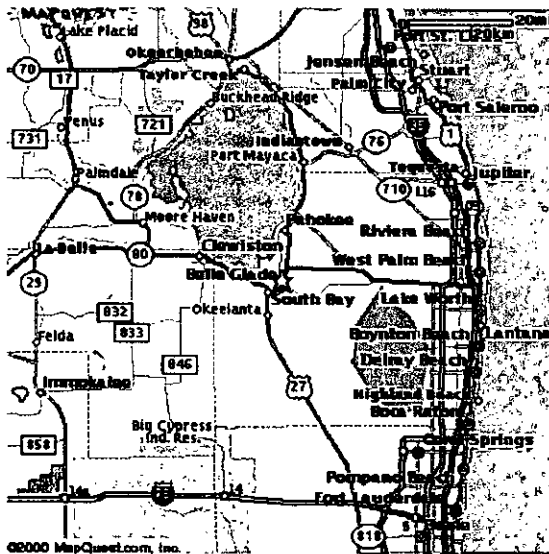


Figure 1 – Location of Belle Glade

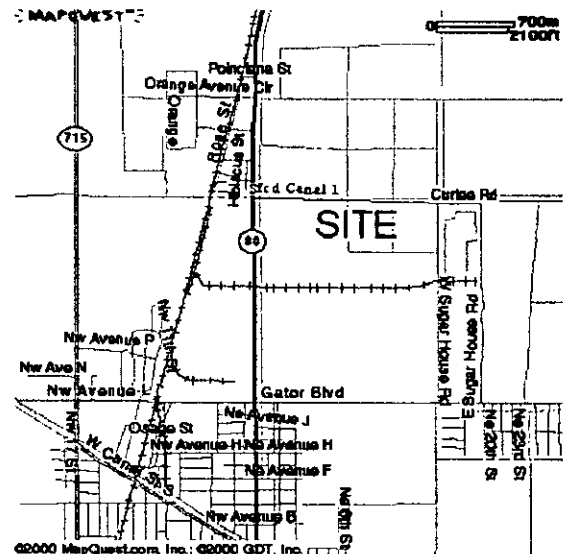


Figure 2 – Proposed Project Site

2.2 Standard Industrial Classification Codes (SIC)

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

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

2.3 Facility Category

This proposed project will generate 600 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/PM₁₀), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), and a Best Available Control Technology (BACT) determination is required. Given that emissions of at least one single criteria pollutant will exceed 100 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, SO₂, and VOC; 25/15 TPY of PM/PM₁₀; 7 TPY of Sulfuric Acid Mist (SAM); and 100 TPY of CO.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

ID	Emission Unit Description
001	Combined Cycle Unit No. CC-1 consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 175 MW, an unfired heat recovery steam generator (HRSG), a separate steam turbine-electrical generator and a 135-foot stack.
002	Simple Cycle Unit No. SC-1 consists of a natural gas-fueled GE 7FA combustion turbine-electrical generator with a nominal capacity of 175 MW and a 135-foot stack.
003	Simple Cycle Unit No. SC-2 consists of a natural gas-fueled GE 7FA combustion turbine-electrical generator with a nominal capacity of 175 MW and a 135-foot stack.
004	Cooling Tower – one 5-cell freshwater mechanical draft cooling tower.
005	Other Emissions Units including one 2600-hp diesel generator, one 250-hp diesel fire pump, one gas heater, aqueous ammonia storage tank and small diesel storage tanks.

Significant emission rate increases per Table 212.400-2, F.A.C. will occur for CO, SO₂, SAM, PM/PM₁₀ and NO_x. A BACT determination is required for each of these pollutants. An air quality impact review is also required for CO, PM/PM₁₀, NO_x, and SO₂.

Each turbine will be equipped with Dry Low NO_x (DLN-2.6) combustors and evaporative inlet cooling systems. Each will have a maximum heat input rating of approximately 1,700 mmBtu per hour while operating at 100% load. El Paso proposes to operate the simple cycle units up to 5,000 hours per year per unit and to operate the combined cycle unit continuously. 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. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

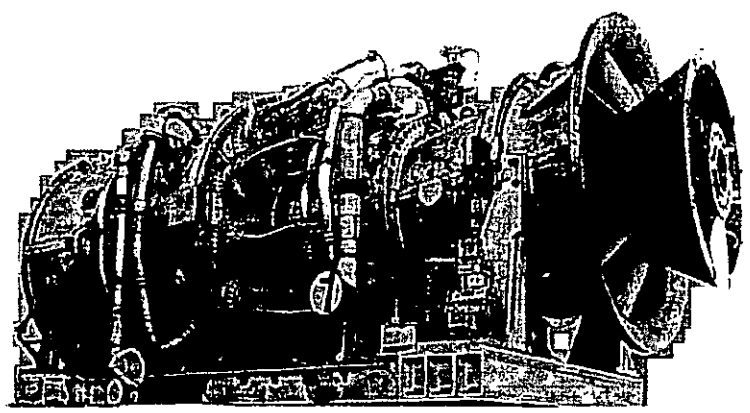
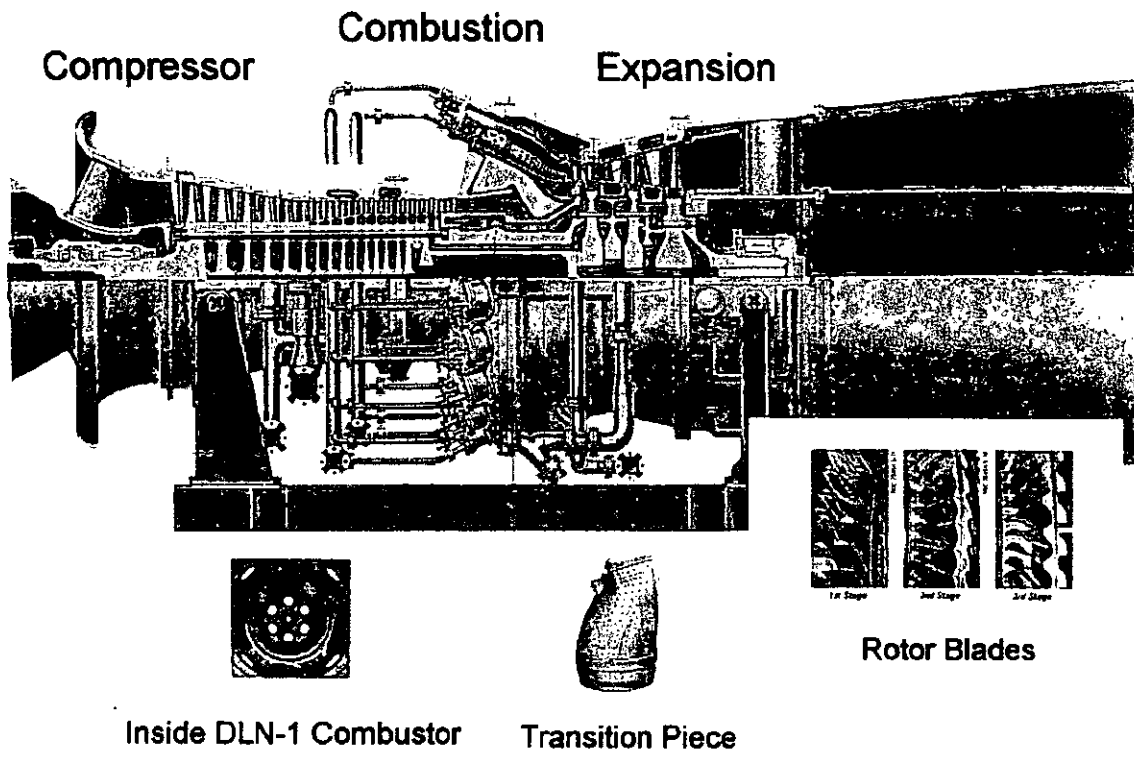
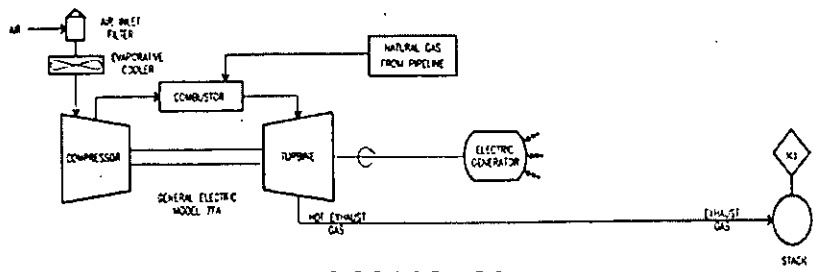
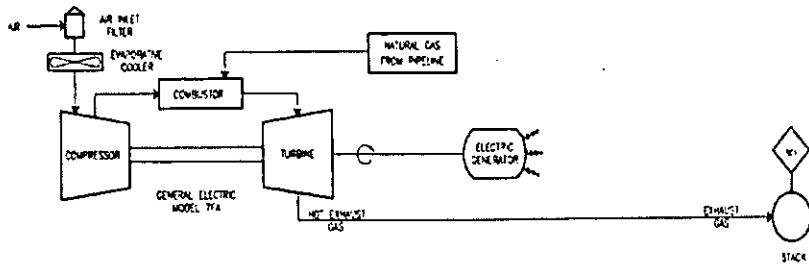


Figure 3 - Internal and External Views of Early GE 7FA



SIMPLE CYCLE UNIT 2



SIMPLE CYCLE UNIT 1

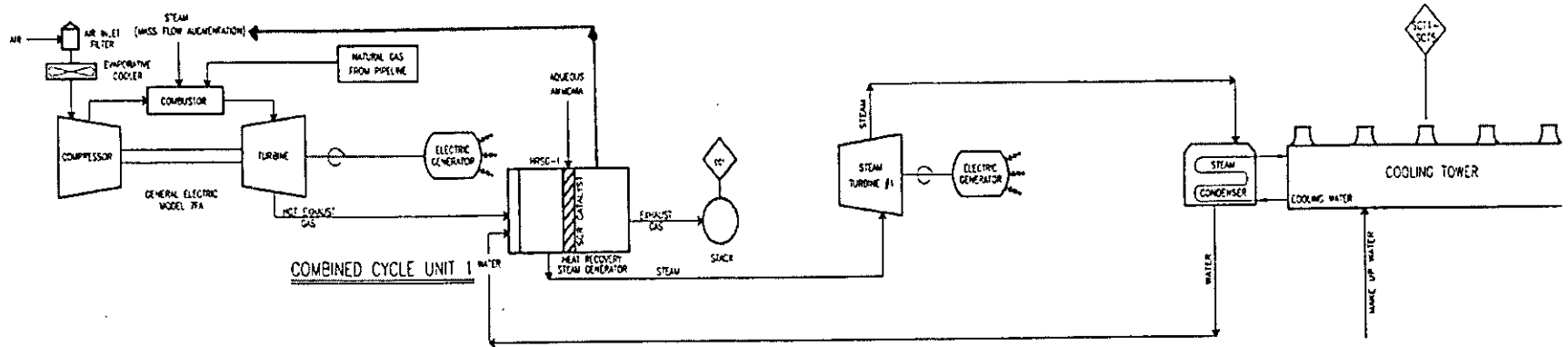
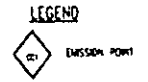


Figure 4. Process Flow Diagram

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

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 El Paso project. Two of the units will operate 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.

One of the units will operate in combined cycle mode in which the combustion 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 a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

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 simple cycle unit by using a chiller to cool the inlet air to 50 °F.

Other possibilities include placing a gas-fired duct burner between the combustion turbine and the HRSG, power augmentation and peaking. Power augmentation is accomplished by injecting some steam from the HRSG into the rotor (power) section of the combustion turbine. Peaking is simply running the unit at greater than design fuel input. The additional process information related to the combustor design, and control measures to minimize pollutant emissions are given in the attached draft BACT determination.

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 project will be located in Palm Beach 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 PSD review under Rule 62-212.400, F.A.C. for the reasons given in Section 2.3, Facility Category, above.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

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/PM₁₀, CO, SO₂, 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, and GG
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2, F.A.C.): PM/PM₁₀, SO₂, 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. 10-16 Section III (Combined Cycle) and Specific Condition Nos. 8-12 Section III (Simple Cycle) of Draft Permit PSD-FL-317.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

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	Emissions ¹	PSD Significance	PSD Review?
PM/PM ₁₀ (filterable plus condensable)	181	25	Yes
SO ₂	69	40	Yes
NO _x	391 ²	40	Yes
CO	349	100	Yes
Ozone (VOC)	29	40	No
Sulfuric Acid Mist	10	7	Yes
Total Fluorides	~0	3	No
Mercury	~0	0.1	No
Lead	0.3	0.6	No
HAPs	6	NA	NA

1. Based on 5,000 hours of natural gas firing per year per simple cycle unit, 8,760 hours per year for the combined cycle unit. Includes emergency diesel engines and cooling tower.

2. NO_x emissions will be 365 TPY based on Department's proposed BACT determination.

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, SO₂, CO, SAM, and PM/PM₁₀. Emissions control will be accomplished primarily by good combustion of clean natural gas. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. A selective catalytic reduction (SCR) system will be installed within the heat recovery steam generator of the single combined cycle unit to effect additional NO_x control. A full discussion is given in the separate Draft Best Available Control Technology (BACT) Determination that is incorporated into this document by reference.

6.4 Existing Air Quality in the Vicinity of the project

6.4.1 Description of Vicinity

Refer to Figure 1 above. The project will be located in Belle Glade, which is at the Southeast corner of Lake Okeechobee. Belle Glade has a population of 16,177 people compared to the 1.1 million in Palm Beach County. Population centers in the County are concentrated towards the east near the coast. There is development towards the west throughout the entire county. However cities in the extreme western part of the county, such as Belle Glade, have experienced little if any growth in recent years.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Refer to Figure 5 below. The specific project location is on the Northeast side of Belle Glade, 0.33 mile East of State Road 80 and South of Curlee Road. The project site and almost all of the surrounding area is agricultural and primarily dedicated to sugar cultivation. There are a number of canals that are used for flood control and field drainage. The processing mills are nearby.

The sugar cane processing season is roughly from April to November and involves open burning of mature cane fields, followed by cane harvesting, delivery to the mills and further processing to raw or refined sugar.

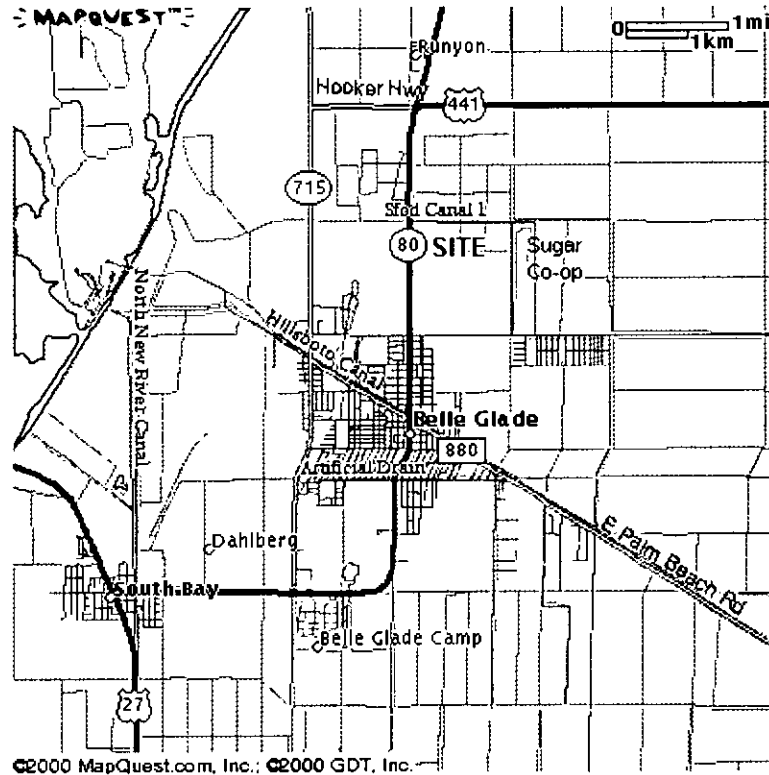


Figure 5 – Local Map and Site Location

Figures 6 and 7 are photographs taken from a point near the project site. Immature cane fields and the sugar mill owned by Sugarcane Growers Co-op are visible in Figure 7.



Figure 6 - View towards West



Figure 7 – Nearby Fields and Mill

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

6.4.2 Climate

The average annual high temperature for Belle Glade is 83 degrees and the average low is 61 degrees. Winds are predominately out of the East. Refer to Figure 8 below.

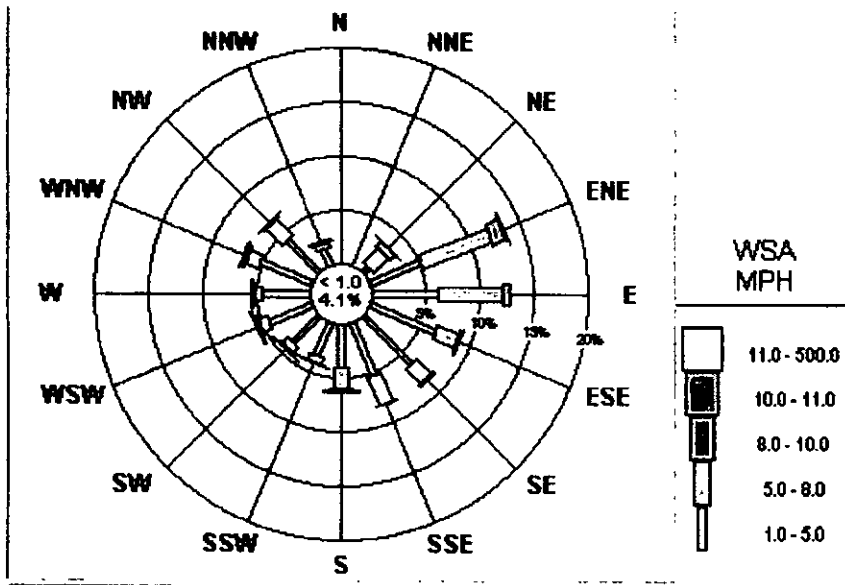


Figure 8 – Palm Beach County Wind Rose – July 2000 to June 2001

6.4.3 Major Stationary Sources in Palm Beach County

The current largest sources of air pollutants in Palm Beach County are listed below. Most are related to the sugar industry.

MAJOR SOURCES OF SO₂ IN PALM BEACH COUNTY (2000)

Owner/Company	Site Name	Tons per year
Atlantic Sugar Association	Atlantic Sugar Mill	611
City of Lake Worth Utilities	Tom G. Smith Power Plant	65
Florida Power & Light	Riviera Power Plant	15795
Okeelanta Corporation	Okeelanta Sugar Mill	73
Okeelanta Power L.P.	Okeelanta Cogeneration Plant	219
Osceola Farms	Osceola Sugar Mill	143
Osceola Power L.P. (not in operation)	Osceola Cogeneration	339 (potential)
Solid Waste Authority of PBC	Solid Waste Authority of PBC/NCRRF	183
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op Mill	594
U.S. Sugar Corporation	Bryant Mill	272
El Paso (Future)	Belle Glades Energy Center	69

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

MAJOR SOURCES OF NO_x IN PALM BEACH COUNTY (2000)

Owner/Company	Site Name	Tons per year
Atlantic Sugar Association	Atlantic Sugar Mill	539
City of Lake Worth Utilities	Tom G. Smith Power Plant	676
Florida Power & Light	Riviera Power Plant	3778
Okeelanta Corporation	Okeelanta Sugar Mill	289
Okeelanta Power L.P.	Okeelanta Cogeneration Plant	831
Osceola Farms	Osceola Sugar Mill	294
Osceola Power L.P. (not in operation)	Osceola Cogeneration	577(potential)
Solid Waste Authority of PBC	Solid Waste Authority of PBC/NCRRF	1114
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op Mill	595
U.S. Sugar Corporation	Bryant Mill	516
United Technologies Corporation	Pratt & Whitney Aircraft	180
El Paso (Future)	Belle Glades Energy Center	365

Total NO_x emissions were 114 tons per day including traffic during 1997.

MAJOR SOURCES OF VOC IN PALM BEACH COUNTY (2000)

Owner/Company	Site Name	Tons per year
Atlantic Sugar Association	Atlantic Sugar Mill	1907
Jupiter Mulch, Inc	Jupiter Mulch, Inc	39
Florida Power & Light	Riviera Power Plant	59
Okeelanta Corporation	Okeelanta Sugar Mill	18
Okeelanta Power L.P.	Okeelanta Cogeneration Plant	51
Osceola Farms	Osceola Sugar Mill	402
Osceola Power L.P. (not in operation)	Osceola Cogeneration Plant	219(potential)
Solid Waste Authority of PBC	Solid Waste Authority of PBC/NCRRF	33
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op Mill	199
U.S. Sugar Corporation	Bryant Mill	353
El Paso (Future)	Belle Glades Energy Center	29

Total VOC emissions were 278 tons per day including traffic during 1997.

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MAJOR SOURCES OF PM IN PALM BEACH COUNTY (2000)

Owner/Company	Site Name	Tons per year
Atlantic Sugar Association	Atlantic Sugar Mill	362
City of Lake Worth Utilities	Tom G. Smith Power Plant	44
Florida Power & Light	Riviera Power Plant	1154
Okeelanta Corporation	Okeelanta Sugar Mill	290
Okeelanta Power L.P.	Okeelanta Cogeneration Plant	640
Osceola Farms	Osceola Sugar Mill	265
Osceola Power L.P. (not in operation)	Osceola Cogeneration	123 (potential)
Palm Beach Aggregates, Inc	Palm Beach Aggregates	103
Solid Waste Authority of PBC	Solid Waste Authority of PBC/NCRRF	167
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op Mill	573
U.S. Sugar Corporation	Bryant Mill	362
El Paso (Future)	Belle Glades Energy Center	181

6.4.4 Air Quality Monitoring in Palm Beach County

Palm Beach County has 11 monitors at 7 sites measuring CO, PM, ozone, SO₂ and NO₂. The 2001 Palm Beach County monitoring network is shown in Figure 9.

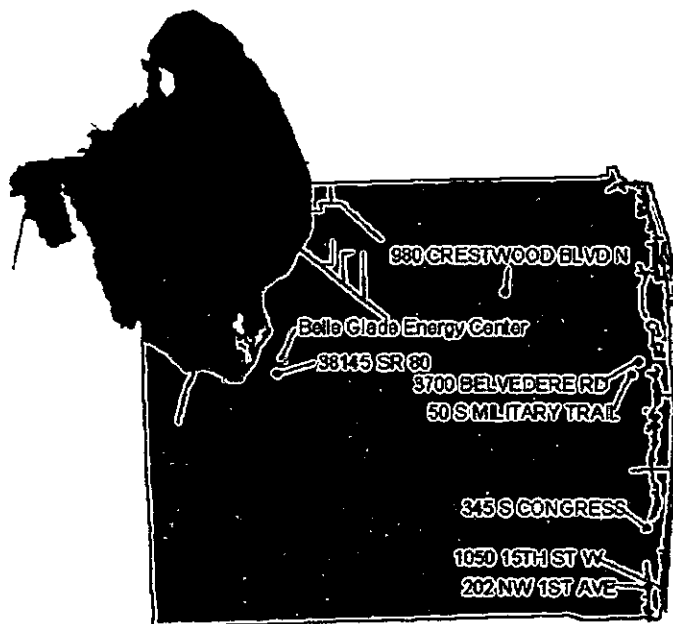


Figure 9 – Palm Beach County Monitoring Network

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

6.4.5 Ambient Air Quality in Palm Beach County

Measured ambient air quality is given in the following table. The highest measured values are all less than the respective National Ambient Air Quality Standards. The average measurements are all much less than the respective standards.

1999 PALM BEACH COUNTY AMBIENT AIR QUALITY

Pollutant	Site Location			Averaging Period	Ambient Concentration				
	City	Site no.	UTM		1st High	2nd High	Mean	Standard	Units
PM ₁₀	Delray Beach*	099-2003	17-2926.170N-	24-hour	47	33	20	150 ^c	ug/m ³
			590.023E	Annual				50 ^b	ug/m ³
SO ₂	Riviera Beach	099-3004	17-2916.800N-	3-hour	17	14		500 ^a	ppb
			592.350E	24-hour	13	13		100 ^a	ppb
				Annual			2	20 ^b	ppb
NO ₂	West Palm Bch	099-1004	17-2952.381N- 589.524E	Annual			13	53 ^b	ppb
CO	West Palm Bch	099-1006	17-2954.550N-	1-hour	6	5		35 ^a	ppm
			588.350E	8-hour	4	3		9 ^a	ppm
Ozone	Delray	099-2004	17-2927.400N- 592.100E	1-hour	0.108	0.104	0.045 ^d	0.12 ^c	ppm

a - Not to be exceeded more than once per year.
 b - Arithmetic mean.
 c - Not to be exceeded on more than an average of one day per year over a three-year period.
 d - Mean ozone value reflects the average daily 1-hour maximum reading Jan.-Sept.99.
 e -Belle Glade PM₁₀ concentrations are lower than Delray. These sites above represent the highest concentrations in the county.

6.5 Air Quality Impact Analysis

6.5.1 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM₁₀, CO, NO_x, SO₂, and SAM. PM₁₀, SO₂ 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/PM₁₀, CO, NO_x, and SO₂ air quality impact analyses for this project predicted significant impacts only for PM₁₀ in the Class II area in the vicinity of the project. Therefore, no further applicable AAQS and PSD increment impact analyses for were CO, NO_x, and SO₂ were required in the Class II area.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

The nearest PSD Class I area is the Everglades National Park (ENP) located about 105 km to the south. The applicant's PSD Class I air quality analysis showed no significant impacts. Therefore, a cumulative PSD Class I increment analysis was not required.

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 PM₁₀, CO, SO₂, and NO₂ in the surrounding Class II Area;
- An Ambient Air Quality Standards (AAQS) and PSD increment analysis for PM₁₀ in the Class II area in the vicinity of the project
- A significant impact analysis for PM₁₀, SO₂, and NO₂ in 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.

6.5.2 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. Substantial monitoring data exist for the area as discussed in the previous sections.

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 Palm Beach County are included for comparison purposes.

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.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

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

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	De Minimis Level (ug/m ³)	Baseline Concentrations (ug/m ³)	Impact Greater Than De Minimis?
PM ₁₀	24-hour	6	10	~ 50	NO
NO ₂	Annual	0.1	14	~ 25	NO
SO ₂	24-hour	0.5	13	~ 35	NO
CO	8-hour	5	575	~ 5000	NO

6.5.3 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.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

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 West Palm Beach International Airport supplemented with precipitation data obtained from NCDC for the period 1987 through 1991 was used along with concurrent upper air data from West Palm Beach.

6.5.4 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 Cartesian receptors at 100 meters apart starting at and extending to 1 kilometer at 100 meter spacing from the fence line. Beyond 1 kilometer, polar receptor rings (with 36 receptors per ring at 10 degree intervals) with a spacing of 100 meters were used out to 2 kilometers from the facility. From 2 to 4 kilometers, polar receptor rings with a spacing of 250 meters were used. Between 4 and 10 kilometers, polar receptor rings with a spacing of 500 meters were used.

For the Class I screening analysis two rings of receptors were centered on the facility at distances bracketing the ENP. These distances represent the nearest boundary and the farthest boundary of the ENP with respect to the proposed project. Receptors were placed at two-degree intervals over a 360-degree arc along each ring. Screening model runs showed insignificant impacts for all pollutants.

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

MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE EL PASO PROJECT FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	Significant Impact Level (ug/m ³)	Significant Impact?
SO ₂	Annual	0.02	1	NO
	24-Hour	0.5	5	NO
	3-Hour	2	25	NO
PM ₁₀	Annual	0.2	1	NO
	24-Hour	6	5	YES

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CO	8-Hour	5	500	NO
	1-Hour	23	2000	NO
NO ₂	Annual	0.1	1	NO

The results of the significant impact modeling show that there are significant impacts for the PM₁₀ 24-hour averaging time predicted due to the emissions from this project in the vicinity of the facility; therefore, further modeling was required in the Class II area.

MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE EL PASO PROJECT COMPARED WITH 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	0.07	0.3	NO
NO ₂	Annual	0.01	0.1	NO
SO ₂	Annual	0.002	0.1	NO
	24-hour	0.03	0.2	NO
	3-hour	0.08	1	NO

The results of the significant impact modeling for the ENP show that there are no significant impacts predicted due to SO₂, NO₂, and PM₁₀ emissions from these projects; therefore, no further modeling was required in the Class I area for these pollutants.

6.5.5 AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

AMBIENT AIR QUALITY IMPACTS

Pollutant	Averaging Time	Major Sources Impact (ug/m ³)	Background Conc. (ug/m ³)	Total Impact (ug/m ³)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m ³)
PM ₁₀	24-hour	83	33	116	NO	150

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6.5.6 PSD Class Increment Analysis for PM₁₀

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 PM₁₀ (the baseline year was 1975 for existing major sources of PM₁₀). The maximum predicted 24-hour PM₁₀ PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of the BEC are shown in the following table. The table shows that the maximum predicted impacts are less than the allowable Class II PM₁₀ increments.

PSD CLASS II INCREMENT ANALYSIS

Pollutant	Averaging Time	Maximum Predicted Impact (µg/m ³)	Impact Greater Than Allowable Increment?	Allowable Increment (µg/m ³)
PM ₁₀	24-hr	14	NO	30

6.5.7 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas-fueled combustion turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM₁₀, CO, NO_x, and SO₂ 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 just slightly greater for PM₁₀ and less than the significant impact levels for all other pollutants. These values in-turn are less than the respective applicable allowable increments.

The total concentrations predicted to occur for NO_x would be about ½ % of the existing NO_x concentrations in Palm Beach County, which is well below the AAQS. Similarly, predicted SO₂ concentrations will be roughly 1.5% of the existing SO₂ concentrations currently measured in the county, which is also, well below the AAQS. The contribution to the total load of these pollutants into the air is very small and will not affect soils in any appreciable manner.

The concentrations of key pollutants are substantially less than values known to cause damage to vegetation. For example, photosynthetic processes are known to be adversely effected from SO₂. SO₂ can react with chlorophyll by causing bleaching. Injury has been documented at exposures of 131 to 1,310 µg/m³ for a period of 8 hours according to the application. The average long-term and maximum short-term SO₂ concentrations caused by the proposed project are several orders of magnitude less (0.02 – 2 µg/m³). It is also noted that, at the site of the only SO₂ station in the county, the annual average and 24-hour concentrations of SO₂ are 5 and 35 µg/m³ respectively. Therefore, the contribution from the proposed project would be minimal.

Similar analyses apply to the other pollutants and their impacts on soil, vegetation and wildlife. The Department's conclusion is that the effects of the project on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility and Regional Haze

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_x and SO₂ emissions will also minimize plume visibility (typically zero percent opacity). The

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contribution to smog in the area will be minimal. The applicant submitted a regional haze analysis for the Everglades National Park. 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. When operational, the project will generate approximately 25 jobs at the site.

The type of project proposed has a small overall physical "footprint," and the lowest air emissions per unit of electric power generating capacity for both combined cycle and simple cycle (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. In making this preliminary determination, the Department also drafted a determination of Best Available Control Technology that may be modified based on comments from the applicant, agencies, and the public.

Teresa Heron, Permit Engineer
Debbie Galbraith, Meteorologist
A. A. Linero, P.E.

SECTION IV. 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.

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

- 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 extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
- G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
- G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
- G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.
- G.13 This permit also constitutes:
- a) Determination of Best Available Control Technology (X)
 - b) Determination of Prevention of Significant Deterioration (X); and
 - c) Compliance with New Source Performance Standards (X).
- G.14 The permittee shall comply with the following:
- a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c) Records of monitoring information shall include:
 - 1. The date, exact place, and time of sampling or measurements;
 - 2. The person responsible for performing the sampling or measurements;
 - 3. The dates analyses were performed;
 - 4. The person responsible for performing the analyses;
 - 5. The analytical techniques or methods used; and
 - 6. The results of such analyses.
- G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SECTION IV. APPENDIX GG
NSPS Subpart GG Requirements for Gas Turbines

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:

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

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 defined 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" value for this unit is approximately 10 for natural gas. The equivalent emission standard is 108 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:

SECTION IV. APPENDIX GG
NSPS Subpart GG Requirements for Gas Turbines

(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:
- (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. 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.

SECTION IV. APPENDIX GG
NSPS Subpart GG Requirements for Gas Turbines

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 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.
- (b) In conducting the performance tests required in 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 provided 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 (NO_x) shall be computed for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

where:

- NO_x = emission rate of NO_x at 15 percent O₂ and ISO standard ambient conditions, volume percent.
- NO_{x0} = observed NO_x 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 H₂O/g air.
- e = transcendental constant, 2.718.
- Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NO_x monitor required by this permit continuously calculate NO_x 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 NO_x monitor shall be used to demonstrate compliance with the BACT NO_x 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 NO_x emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

SECTION IV. APPENDIX GG
NSPS Subpart GG Requirements for Gas Turbines

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NO_x 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 NO_x 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 specifies sulfur testing methods.

[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.]

SECTION IV. APPENDIX XS
CONTINUOUS MONITOR SYSTEMS SEMI-ANNUAL REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant (*Circle One*): Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer and Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ^a: _____

Emission data summary ^a	CMS performance summary ^a
1. Duration of Excess Emissions In Reporting Period Due To:	1. CMS downtime in reporting period due to:
a. Startup/Shutdown	a. Monitor Equipment Malfunctions
b. Control Equipment Problems	b. Non-Monitor Equipment Malfunctions
c. Process Problems	c. Quality Assurance Calibration
d. Other Known Causes	d. Other Known Causes
e. Unknown Causes	e. Unknown Causes
2. Total Duration of Excess Emissions	2. Total CMS Downtime
3. $\frac{[\text{Total Duration of Excess Emissions}] \times (100\%)}{[\text{Total Source Operating Time}]^b}$	3. $\frac{[\text{Total CMS Downtime}] \times (100\%)}{[\text{Total source operating time}]}$

^a For opacity, record all times in minutes. For gases, record all times in hours.

^b For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months.

I certify that the information contained in this report is true, accurate, and complete.

Name

Title

Signature

Date

SECTION IV. APPENDIX SC
STANDARD CONDITIONS

{Permitting Note: The following conditions apply to all emissions units and activities at this facility.}

EMISSIONS AND CONTROLS

1. **Plant Operation - Problems:** If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. **Circumvention:** The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. **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. [Rule 62-210.700(4), F.A.C.]
4. **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.]

TESTING REQUIREMENTS

5. **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), F.A.C.]
6. **Calculation of Emission Rate:** For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
7. **Test Procedures:** Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
 - a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
 - b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
 - c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

[Rule 62-297.310(4), F.A.C.]

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

8. Determination of Process Variables

- a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

9. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.
10. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]
11. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

12. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]
13. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]
14. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

PERMITTEE:

El Paso Merchant Energy Company
1001 Louisiana Street
Houston, TX 77002

Authorized Representative:
William Mack, Sr., Managing Director

Facility Name: Belle Glade Energy Center Project No. 0990594-001-AC Air Permit No. PSD-FL-317 Facility ID No. 0990594 SIC No. 4911 Expires: December 1, 2004

PROJECT AND LOCATION

This permit authorizes the construction of a new nominal 600-megawatt electrical generating plant, the Belle Glade Energy Center, to be located 0.33 Mile East of SR 80, South of Curlee Road in Belle Glade, Palm Beach County. UTM coordinates are: Zone 17; 533.5 km East; 2,954.1 km North. The plant will consist of one combined cycle gas turbine, two simple cycle gas turbines, and associated equipment.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The proposed project is for a new electrical power plant, the Belle Glade Energy Center, which will generate a nominal 600 MW of electricity. The plant will consist of one combined cycle gas turbine unit (250 MW, total) and two simple cycle gas turbine units (175 MW, each).

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
001	Combined Cycle Unit No. CC-1 consists of a natural gas fired 175 MW General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator, and a separate steam turbine-electrical generator.
002	Simple Cycle Unit No. SC-1 consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.
003	Simple Cycle Unit No. SC-2 consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.
004	Cooling Tower consisting of one 5-cell freshwater mechanical draft freshwater cooling tower.
005	Other Emissions Units include one 2600-hp diesel generator, one 250-hp diesel fire pump, a 12.8 MMBtu/hr (HHV) gas-fired fuel heater, an aqueous ammonia storage tank, and small diesel storage tanks.

REGULATORY CLASSIFICATION

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new gas turbines are subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the new facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: The new gas turbines are subject to the New Source Performance Standards of 40 CFR 60, Subpart GG. The gas fired fuel heater is subject to the New Source Performance Standards of 40 CFR 60, Subpart Dc.

NESHAP: No emission units are identified as being subject to a National Emissions Standards for Hazardous Air Pollutants (NESHAP).

SITING: The project is not subject to Section 403.501-518, F.S., Florida Electrical Power Plant Siting Act, based on information regarding gross electrical power generated from the steam (Rankine) cycle submitted by the applicant and reviewed by the Department.

SECTION I. GENERAL INFORMATION

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.

COMPLIANCE AUTHORITIES

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the Palm Beach County Health Department, P.O. Box 29, West Palm Beach, Florida 33402-0029. Copies of all such documents shall be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, Post Office Box 15425, West Palm Beach, Florida 33416-5425.

APPENDICES

The following Appendices are attached as part of this permit.

- Appendix BD. Final BACT Determinations and Emissions Standards
- Appendix GC. General Conditions
- Appendix GG. NSPS Subpart GG Requirements for Gas Turbines
- Appendix SC. Standard Conditions
- Appendix XS. Continuous Monitor Systems Semi-Annually Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on 03/28/01 and all related completeness correspondence.
- Draft permit package issued on 09/07/01.
- Comments received from the public, the applicant, the EPA Region 4 Office, and the National Park Service.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
4. Completion of Construction: The permit expiration date is December 1, 2004. Physical construction shall be completed by September 1, 2004. The additional time provides for testing, submittal of results, and submittal of the Title V permit application to the Department.
5. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]
6. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]
7. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
9. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]
10. 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 90 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 copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. COMBINED CYCLE GAS TURBINE

This section of the permit addresses the following new emissions unit.

Emissions Unit 001: Combined Cycle Gas Turbine No. CC-1

Description: The combined cycle unit consists of a General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW, an unfired heat recovery steam generator (HRSG), and a separate steam turbine-electrical generator set. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, and an evaporative inlet air-cooling system.

Fuel: The combined cycle unit is fired exclusively with pipeline-quality natural gas.

Capacity: At a compressor inlet air temperature of 35° F, the combined cycle gas turbine produces approximately 180 MW when firing approximately 1700 MMBtu (LHV) per hour of natural gas.

Controls: The efficient combustion of pipeline-quality natural gas at high temperatures minimizes emissions of CO, PM/PM₁₀, SAM, SO₂, and VOC. A selective catalytic reduction (SCR) system combined with Dry Low-NO_x (DLN) combustion technology reduces NO_x emissions.

Stack Parameters: When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit a 135 feet tall stack that is 19.0 feet in diameter with a flow rate of approximately 1,040,000 acfm at 187° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions standards specified for this unit represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), and sulfur dioxide (SO₂). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

EQUIPMENT

2. Combined Cycle Gas Turbine: The permittee is authorized to install, tune, maintain and operate a new combined cycle unit consisting of a General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set. The combined cycle unit shall be designed as a system to generate a nominal 175 MW of shaft-driven electrical power and less than 75 MW of steam-generated electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a single exhaust stack that is 135 feet tall and 19.0 feet in diameter, and associated support equipment. A separate bypass stack and damper may be installed to facilitate startup of the steam cycle while operating the combustion turbine in Low Emissions Modes 5, 5Q, and 6Q. [Applicant Request; Design]
3. DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric DLN-2.6 combustion system to control NO_x emissions from the combined cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]
4. (SCR) System: The permittee shall install, tune, maintain and operate a selective catalytic reduction (SCR) system to control NO_x emissions from the combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, electrical, piping and other auxiliary equipment. The SCR system shall be designed to reduce NO_x emissions and ammonia slip below the permitted levels. [Rule 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. COMBINED CYCLE GAS TURBINE

PERFORMANCE RESTRICTIONS

5. Permitted Capacity: The maximum heat input rate to the combined cycle gas turbine shall not exceed 1742 MMBtu per hour based on a compressor inlet air temperature of 35° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]
6. Authorized Fuel: The combined cycle gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]
7. Restricted Operation: The hours of operation for the combined cycle gas turbine are not limited (8760 hours per year). [Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]
8. Power Augmentation: As an alternate method of operation, the permittee may inject steam into the combined cycle gas turbine for power augmentation. Power augmentation is permitted 2000 hours per 12-consecutive months and is not limited if oxidation catalyst is installed. The 2000 hour limit may be revised at the request of the applicant based upon review of actual performance and control equipment cost-effectiveness following proper public notice. [Rule 62-212.400 (BACT), F.A.C.]
9. Power Generated Limitation: Electrical power from the steam-electrical generator shall be limited to 74.9 MW (gross) on an hourly basis. The owner or operator shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system. [Applicant Request]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to the combined cycle gas turbine. Unless otherwise noted, the mass emission limits are based a compressor inlet temperature of 35° F and 100% load. For comparison to the standard, actual measured concentrations shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

10. Ammonia Slip: Ammonia slip shall not exceed 5 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method CTM-027. [Rule 62-4.070(3), F.A.C.]
11. Carbon Monoxide (CO)
 - a. Initial Test, Standard Operation: When not operating in the power augmentation mode, CO emissions shall not exceed 31.0 pounds per hour nor 8.0 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.
 - b. Continuous Compliance, Standard Operation: When not operating in the power augmentation mode, CO emissions shall not exceed 8.0 ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. COMBINED CYCLE GAS TURBINE

- c. *Initial Test, Power Augmentation*: When injecting steam for power augmentation and a compressor inlet temperature of 59° F, CO emissions shall not exceed 48.0 pounds per hour nor 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.
- d. *Continuous Compliance, Power Augmentation*: When injecting steam for power augmentation, CO emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system. [Rule 62-212.400(BACT), F.A.C.]
12. Nitrogen Oxides (NO_x)
- a. *Initial Test*: NO_x emissions shall not exceed 17.0 pounds per hour nor 2.5 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method 7E.
- b. *Continuous Compliance*: NO_x emissions shall not exceed 2.5 ppmvd corrected to 15% oxygen based on a 24-hour block average as determined by valid data collected from the certified CEM system.
- NO_x emissions are defined as oxides of nitrogen expressed as NO₂. [Rule 62-212.400(BACT), F.A.C.]
13. Particulate Matter (PM/PM₁₀): The fuel specifications established in Condition No. 6 of this section combined with the efficient combustion design and operation of the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. {Permitting Note: Particulate matter emissions are expected to be less than 11 pounds per hour as determined by EPA Method 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]
14. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO₂): The fuel sulfur specification established in Condition No. 6 of this section effectively limits the potential emissions of SAM and SO₂ from the combined cycle gas turbine. Compliance with the fuel sulfur specification shall be demonstrated by the sampling, analysis, record keeping and reporting requirements established in Section III.C of this permit. [Rule 62-212.400(BACT), F.A.C.]
15. Visible Emissions: As determined by EPA Method 9, visible emissions shall not exceed 10% opacity based on a 6-minute average. Except as allowed by Condition No. 17 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]
16. Volatile Organic Compounds (VOC): The efficient combustion of clean fuels and good operating practices for the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the fuel specification and CO standards shall serve as indicators of good combustion. {Permitting Note: VOC emissions are expected to be less than 3 pounds per hour and 1.3 ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of the combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.
- a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.
- b. *Work Practice BACT*: The unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. COMBINED CYCLE GAS TURBINE

- c. *Low-Load Restriction*: Except for startup and shutdown, operation under DLN Modes 1, 2, 3, and 4 is prohibited.
- d. *CEM System Data Exclusion*: Except for combined cycle cold startups, no more than two hourly average emission rate values in a calendar day shall be excluded from the continuous NO_x and CO compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than four hourly average emission rate values in a calendar day shall be excluded from the continuous NO_x and CO compliance demonstrations due to combined cycle cold startups. No more than a total of four hourly average emission rate values shall be excluded from the continuous NO_x and CO compliance demonstrations for all such episodes in any calendar day. A "*combined cycle cold startup*" is defined as startup after the combined cycle gas turbine has been shutdown for 48 hours or more. A "*documented unavoidable malfunction*" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

[Design; Rules 62-4.070(3), 62-4.130, 62-210.700, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{*Permitting Note: Performance test methods are specified in Gas Turbine Common Conditions, Section III.C.*}

18. Initial Compliance Tests: The combined cycle gas turbine shall be tested initially and upon permit renewal to demonstrate compliance with the emission standards for CO, NO_x, visible emissions and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of the combined cycle gas turbine. With appropriate flow measurements, certified CEM system data may be used to demonstrate compliance with the CO and NO_x standards. NO_x emissions recorded by the CEM system shall be reported for each ammonia slip test run. [Rule 62-297.310(7)(a)1., F.A.C.]
19. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the combined cycle gas turbine shall be tested to demonstrate compliance with the emission standards for NO_x, CO, ammonia slip and visible emissions. NO_x emissions recorded by the CEM system shall be reported for each ammonia slip test run. Annual compliance with the applicable NO_x and CO emissions standards can also be demonstrated with valid data collected by the required annual RATA at permitted capacity. {*Permitting Note: Continuous compliance with the CO and NO_x standards shall be demonstrated with certified CEMS system data.*} [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

20. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record the emissions of CO and NO_x from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. The CEM systems shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C.
 - a. The CO monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. For purposes of determining compliance with the CEM emission standards of this permit, missing or excluded data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour block average for CO. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding CO emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. COMBINED CYCLE GAS TURBINE

- b. The NO_x monitor shall have a span of no more than 10 ppmvd corrected to 15% oxygen. Compliance with the continuous NO_x emissions standards shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the CEM emission standards of this permit, missing (or excluded) data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding NO_x emissions standards specified in this section.
[Rule 62-212.400(BACT), F.A.C.]

21. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

OTHER REQUIREMENTS

The combined cycle gas turbine is also subject to the "Gas Turbine Common Conditions" specified in Section III.C as well as the "Standard Conditions" included as Appendix SC in Section IV.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. SIMPLE CYCLE GAS TURBINES

This section of the permit addresses the following new emissions units.

Emissions Units 002, and 003: Simple Cycle Gas Turbine Nos. SC-1 and SC-2

Description: Each simple cycle unit consists of a General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, and an evaporative inlet air-cooling system.

Fuel: Each simple cycle unit is fired exclusively with pipeline-quality natural gas.

Capacity: At a compressor inlet air temperature of 35° F and firing approximately 1700 MMBtu (LHV) per hour of natural gas, each unit produces approximately 180 MW.

Controls: Emissions of CO, PM/PM₁₀, SAM, SO₂, and VOC are minimized by the efficient combustion of pipeline-quality natural gas at high temperatures. NO_x emissions are reduced by Dry Low-NO_x (DLN) combustion technology.

Stack Parameters: When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit a 135 feet tall stack that is 19.0 feet in diameter with a flow rate of approximately 2,500,000 acfm at 1092° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions standards specified for these emissions units represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), and sulfur dioxide (SO₂). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

EQUIPMENT

2. Simple Cycle Gas Turbines: The permittee is authorized to install, tune, maintain and operate two new General Electric Model PG7241(FA) gas turbine-electrical generator sets. Each simple cycle unit shall be designed and operated to generate a nominal 175 MW of shaft-driven electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, a compressor inlet air evaporative cooling system, a single exhaust stack that is 135 feet tall and 19.0 feet in diameter, and associated support equipment. [Applicant Request; Design]
3. DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric DLN 2.6 combustion system to control NO_x emissions from each simple cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Simple Cycle Operation Only: Each gas turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NO_x BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NO_x BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to restricted operation. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NO_x BACT analysis (as if never constructed) and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. The results of this analysis

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. SIMPLE CYCLE GAS TURBINES

may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards.

[Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

5. Permitted Capacity: The maximum heat input rate to each simple cycle gas turbine shall not exceed 1743 MMBtu per hour based on a compressor inlet air temperature of 35° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]
6. Fuel Specifications: Each simple cycle gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]
7. Restricted Operation: The two combustion turbines shall operate no more than an average of 5,000 hours per installed unit during any consecutive 12-month period. Each simple cycle gas turbine shall fire no more than 8,500,000 MMBtu of natural gas (LHV) during any consecutive 12-month period. {Permitting Note: This is approximately equivalent to 5000 hours of operation at 100% load.} [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to each simple cycle gas turbine. Unless otherwise noted, the mass emission limits are based a compressor inlet temperature of 35° F and 100% load. For comparison to the standard, actual measured concentration shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

8. Carbon Monoxide (CO): CO emissions from each simple cycle gas turbine shall not exceed 31.0 pounds per hour nor 8.0 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]
9. Nitrogen Oxides (NO_x)
 - a. *Initial Performance Test*: NO_x emissions from each simple cycle gas turbine shall not exceed 61.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load as determined by EPA Method 7E.
 - b. *CEM System*: NO_x emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average as determined by valid data collected from the certified NO_x CEM system.NO_x emissions are defined as oxides of nitrogen expressed as NO₂. [Rule 62-212.400(BACT), F.A.C.]
10. Particulate Matter (PM/PM₁₀): The fuel specifications established in Condition No. 6 of this section combined with the efficient combustion design and operation of the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Particulate matter emissions are expected to be less than 9 pounds per hour as determined by EPA Method 5, front-half catch only. [Rule 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. SIMPLE CYCLE GAS TURBINES

11. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO₂): The fuel sulfur specification established in Condition No. 6 of this section effectively limits the potential emissions of SAM and SO₂ from each simple cycle gas turbine. Compliance with the fuel sulfur specification shall be demonstrated by the sampling, analysis, record keeping and reporting requirements established in Section III.C of this permit.
[Rule 62-212.400(BACT), F.A.C.]

12. Volatile Organic Compounds (VOC)

a. *Initial Performance Test*: VOC emissions from each simple cycle gas turbine shall not exceed 3.0 pounds per hour nor 1.3 ppmvd corrected to 15% oxygen based on a 3-hour test average at base load as determined by EPA Method 25A, measured and reported in terms of methane. Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
[Rule 62-4.070, F.A.C.; To Avoid Rule 62-212.400(BACT), F.A.C.]

b. *After Initial Performance Test*: The efficient combustion of a clean fuel and good operating practices minimize VOC emissions from each simple cycle gas turbine. Compliance with the fuel specifications and CO standards of this section shall serve as indicators of good combustion. Subsequent VOC emissions performance tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C.
[Rule 62-4.070, F.A.C.]

EXCESS EMISSIONS

13. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of each simple cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

- a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.
- b. *Work Practice BACT*: The unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.
- c. *Low-Load Restriction*: Except for startup and shutdown, operation under DLN Modes 1, 2, 3, and 4 is prohibited.
- d. *CEM System NO_x Data Exclusion*: No more than two hourly average emission rate values shall be excluded from the continuous NO_x compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than a total of three hourly average emission rate values shall be excluded from the continuous NO_x compliance demonstrations for such periods in any calendar day. A "documented unavoidable malfunction" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

[Design; Rules 62-210.700, 62-4.130, and 62-212.400 (BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. SIMPLE CYCLE GAS TURBINES

EMISSIONS PERFORMANCE TESTING

{Permitting Note: Performance test methods are specified in Gas Turbine Common Conditions, Section III.C.}

14. **Initial Tests Required:** Each simple cycle gas turbine shall be tested initially and upon permit renewal to demonstrate compliance with the emission standards for PM/PM₁₀, CO, NO_x, VOC and visible emissions. The initial tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each unit. With appropriate flow measurements, certified CEM system data may be used to demonstrate compliance with the NO_x standards. Tests for CO and VOC emissions shall be conducted concurrently. [Rule 62-297.310(7)(a)1., F.A.C.]
15. **Annual Performance Tests:** During each federal fiscal year (October 1st to September 30th), each simple cycle gas turbine shall be tested to demonstrate compliance with the emission standards for NO_x, CO and visible emissions. Annual compliance with the applicable NO_x and CO emissions standards can also be demonstrated with valid data collected by the required annual RATA at permitted capacity. NO_x emissions recorded by the CEM system shall be reported for each CO test run. {Permitting Note: Continuous compliance with the NO_x standard shall be demonstrated with certified CEMS system data.} [Rule 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

16. **CEM Systems:** The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record NO_x emissions from each simple cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. Each CEM system shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C. Each NO_x monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. Compliance with the continuous NO_x emissions standards shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the CEM emission standards of this permit, missing (or excluded) data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding NO_x emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

OTHER REQUIREMENTS

Each simple cycle gas turbine is also subject to the "Gas Turbine Common Conditions" specified in Section III.C as well as the "Standard Conditions" included as Appendix SC in Section IV.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. GAS TURBINE COMMON CONDITIONS

This section of the permit addresses the following new emissions units.

ID	Emission Unit Description
001	Combined Cycle Unit No. CC-1 consists of a natural gas fired General Electric Model PG7241FA 175 MW gas turbine-electrical generator set, an unfired heat recovery steam generator, and a separate turbine-electrical generator.
002	Simple Cycle Unit No. SC-1 consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.
003	Simple Cycle Unit No. SC-2 consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.

NEW SOURCE PERFORMANCE STANDARDS, SUBPART GG

1. NSPS Requirements: The Department determines that compliance with the emissions performance and monitoring requirements of Sections III.A and B also demonstrates compliance with the New Source Performance Standards for gas turbines in 40 CFR 60, Subpart GG. For completeness, the applicable Subpart GG requirements are included in Appendix GG of this permit. [Rule 62-4.070(3), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combined cycle gas turbine and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

3. 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. All such emissions shall be included in any compliance demonstration based on continuous monitoring data. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
5	Determination of Particulate Matter Emissions from Stationary Sources {Note: For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. GAS TURBINE COMMON CONDITIONS

Test Methods, Continued

Method	Description of Method and Comments
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: 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 {Note: EPA Method 18 may be used (optional) 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 Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "<http://www.epa.gov/ttn/emc/ctm.html>". No other methods may be used for compliance testing unless prior written approval is received from the Department.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

CONTINUOUS MONITORING REQUIREMENTS

5. **CEM Systems:** Each continuous emissions monitoring (CEM) system shall comply with the following requirements:
 - a. **CO Monitors.** The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. 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 Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and 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.
 - b. **NO_x Monitors.** Each NO_x 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. 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 20 or 7E, of Appendix A of 40 CFR 60.
 - c. **O₂ or CO₂ Monitors.** The oxygen (O₂) content or carbon dioxide (CO₂) content of the flue gas shall also be monitored at the location where CO and/or NO_x are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ 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 fired. Each O₂ and CO₂ monitor 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 quarterly to each Compliance Authority. The RATA tests required for the O₂ or CO₂ monitors shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. GAS TURBINE COMMON CONDITIONS

- d. *Data Collection.* Each hourly average 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 permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. The CEM system shall be designed and operated to sample, analyze, and record data evenly spaced over an 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. The CEM system shall be used to demonstrate compliance with the CEM emission standards for CO and NO_x as specified in this permit. Upon request by 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.
- e. *Data Exclusion.* All required emissions data shall be recorded by the CEM systems during episodes of startup, shutdown and malfunction. CO and NO_x emissions data recorded during such episodes may be excluded from the corresponding compliance-averaging period subject to the conditions specified in Sections III.A and B of this permit. 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.
- f. *Data Exclusion Reports.* A summary report of the duration of data excluded from each compliance average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. 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 be defined to 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 include 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 quarterly, including periods in which no data is excluded or no instances of missing data occur.
- g. *Notification:* If a CEM system reports CO or NO_x emissions in excess of an emissions standard, the permittee shall notify each Compliance Authority 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.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. GAS TURBINE COMMON CONDITIONS

- h. *Availability.* Monitor availability for CO and NO_x CEM systems shall be 95% or greater in any calendar quarter. The report required in Appendix XS of this permit shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

{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.]

RECORDS

6. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis 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) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]
7. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of fuel consumption for each gas turbine in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
8. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption (million cubic feet of natural gas per month), heat input rates (million BTU per month), and hours of operation for each gas turbine. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

REPORTS

9. Semi-Annually Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, emissions shall be reported as "excess emissions" when emission levels exceed the standards specified in this permit (including periods of startup, shutdown and malfunction). Within 30 days following the end of the six month period, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions, periods of data exclusion, and CEMS systems monitor availability for the previous six month period.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

D. OTHER EMISSIONS UNITS

This permit authorizes installation of the following emissions units.

ID	Emission Unit Description
004	Cooling Tower : One 5-cell mechanical draft fresh water cooling tower.
005	Other Emissions Units : One 2600 hp diesel generator, one 250 hp diesel fire pump, aqueous ammonia storage tank, a 12.8 MMBtu/hr (HHV) gas-fired fuel heater and two diesel fuel storage tanks (less than 1000 gallons).

1. Cooling Tower: BACT for the Cooling Tower was determined to be the use of fresh water and drift eliminators designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. {Permitting Note: Potential emissions in tons per year are expected to be less than 1.64 for PM and 0.99 for PM₁₀}.
2. 2600 HP Diesel Generator: This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)20. F.A.C., provided that fuel oil use does not exceed 32,000 gallons per year. The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.12 for PM, 3.26 for NO_x, 0.73 for CO, 0.07 for SO₂ and 0.18 for TOC (total organic carbons)}.
3. 12.8 MMBtu/hr Gas-fired Natural Gas Fuel Heater: This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)2 F.A.C., Categorical Exemptions. This unit is subject to applicable provisions of 40 CFR 60, Subpart Dc. New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units.
4. 250 HP Diesel Fire Pump: This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)21 F.A.C., Categorical Permit Exemptions. The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.013 for PM, 0.74 for NO_x, 0.18 for CO, 0.0014 for SO₂ and 0.08 for TOC (total organic carbons)}
5. Aqueous Ammonia Storage Tank: This unit will contain less than a 20 percent concentration of aqueous ammonia by volume and therefore is not subject to applicable provisions of 40 CFR 68, Chemical Accident Provisions.
6. Two Diesel Fuel Storage Tanks (less than 1000 gallons): This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(b)(iv) F.A.C., Generic and Temporary Exemptions.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

El Paso Belle Glade Energy Center
PSD-FL-317 and 0990594-001-AC
Palm Beach, Florida

BACKGROUND

The applicant, El Paso Merchant Energy Company (El Paso), proposes to install three nominal 175-megawatt (MW) General Electric PG 7241FA (GE 7FA) combustion turbine-electrical generators at the planned Belle Glade Energy Center in Palm Beach County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.b., Florida Administrative Code (F.A.C.). 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 PM₁₀), carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO₂), 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.

Two of the units will operate in simple cycle mode and intermittent duty while the third will operate in combined cycle mode and continuous duty. The units will exhaust through separate 135-foot stacks. The units will be fired exclusively with pipeline natural gas. El Paso proposes to operate the simple cycle units up to 5,000 hours per year per unit. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination, accompanying the Department's Intent to Issue dated September 5, 2001.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on March 28, 2001 (complete June 27) and included a BACT proposal prepared by the applicant's consultant, ECT.

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 Selective Catalytic Reduction	9 ppmvd @ 15% O ₂ (simple cycle units) 3.5 ppmvd @ 15% O ₂ (combined cycle)
Particulate Matter	Pipeline Natural Gas Combustion Controls	18.3 pounds per hour (Front + Back Half, Simple) 20 pounds per hour (Front + Back Half, Combined)
Carbon Monoxide	As Above	7.4 ppmvd (Full load, Simple or Combined) 12 ppmvd (Combined Cycle Steam Augmentation)
Sulfur Oxides	As Above	1.5 grains sulfur/100 std cubic feet

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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, particularly when permits are issued by states acting on behalf of EPA. The Department considers Top-Down to be a useful tool, though not a unique or required approach to achieve a BACT under the State regulations. 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% O₂ (assuming 25 percent efficiency) and 150 ppmvd SO₂ @ 15% O₂ (or <0.8% sulfur in fuel). The BACT proposed by El Paso 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 El Paso project.

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 and combined cycle turbines. The proposed El Paso project is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

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

Project Location	Power Output (MW)	NO _x Limit ppmvd @ 15% O ₂ and Fuel	Technology	Comments
El Paso Belle Glade, FL	350	9 - NG	DLN	2x175 MW GE 7FA CTs Draft 9/2001. Gas Only
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Draft 8/2001. Gas Only
Enron Deerfield, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 1000 hrs on oil
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 03/01. 1000 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 - NG 42 - No. 2 F.O.	DLN WI	2x165 MW GE 7FA 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
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA 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 7FA 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

El Paso Belle Glade Energy Center
600-Megawatt Gas Turbine Power Plant

DEP File No. 0990594-001-AC (PSD-FL-317)
Palm Beach County

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 2

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

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
El Paso Belle Glade, FL	8 (7.4@15% O ₂) - NG	1.4 (1.3@15% O ₂)	18 lb/hr (Front & Back)	Clean Fuels Good Combustion
El Paso Deerfield, FL	8 (7.4@15% O ₂) - NG	1.4 (1.3@15% O ₂)	18 lb/hr (Front & Back)	Clean Fuels Good Combustion
Enron Deerfield, FL	9 - NG 30 - FO	1.4 - NG 1.4 - FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 - NG 1.4 - FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 - NG 1.4 - FO	10 lb/hr - NG 17 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
TEC Polk Power, FL	15 - NG 33 - FO	7 - NG 7 - FO	10% Opacity	Clean Fuels Good Combustion
Dynergy, FL	25 - NG	? - NG	? - NG	Clean Fuels Good Combustion
Dynergy 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
Dynergy 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

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TABLE 3

RECENT NO_x EMISSION LIMIT DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE
PROJECTS IN THE SOUTHEAST

Project Location	Capacity Megawatts	NO _x Limit ppmvd @ 15% O ₂ and Fuel	Technology	Comments
El Paso Belle Glade, FL	250	2.5 - NG	SCR	175 MW GE 7FA Draft 9/2001
El Paso Deerfield, FL	250	2.5 - NG	SCR	175 MW GE 7FA Draft 8/2001
CPV Pierce, FL	245	2.5 - NG 10 - FO	SCR	170 MW GE 7FA CT 7/2001
Metcalf Energy, CA	600	2.5 - NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce, FL	~250	3.5 - NG 10 - FO	SCR	170 MW MHI501F CT Repowering
CPV Atlantic, FL	245	3.5 - NG 10 - FO	SCR	170 MW GE 7FA CT
TECO Bayside, FL	1750	3.5 - NG 12 - FO	SCR	7x170 MW GE 7FA CTs Repowering
FPC Hines II, FL	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F
Calpine Osprey, FL	527	3.5 - NG	SCR	2x170 MW WH501F Draft 5/00
Calpine Blue Heron, FL	1080	3.5 - NG	SCR	4x170 MW WH501F Draft 2/00
Santee Cooper, SC	~500	9 - NG	DLN	2x170 MW GE 7FA CTs ~ 4/00
Mobile Energy, AL	~250	~3.5 - NG ~11 - FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 - NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 - NG (12 - simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
Lake Worth LLC, FL	250	9 or 3.5 - NG 9.4 or 3.5 - NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 - NG	SCR	4x170 MW GE 7FA CTs 11/98

DB = Duct Burner

NG = Natural Gas

FO = Fuel Oil

DLN = Dry Low NO_x Combustion

SCR = Selective Catalytic Reduction

WI = Water or Steam Injection

GE = General Electric

WH = Westinghouse

CT = Combustion Turbine

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TABLE 4
RECENT CO, VOC, AND PM NO_x EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppmv (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
El Paso Belle Glade, FL	9 (7.4 @15% O ₂) 15 (12 @15% O ₂) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Deerfield, FL	9 (7.4 @15% O ₂) 15 (12 @15% O ₂) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Pierce, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 - FO	1.4 - NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Metcalf Energy, CA	6 - NG (100% load)	.00126 lb/mmBtu-NG	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Enron Ft. Pierce, FL	3.5 - NG 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity	Oxidation Catalyst Clean Fuels Good Combustion
CPV Atlantic, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 - FO	1.4 - NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	9 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)	1.3 – NG 3 - FO	12 lb/hr – NG 30 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	16 - NG (24-hr CEMS) 30 – FO (24-hr CEMS)	2 – NG 10 – FO	10% Opacity – NG 5/9 ammonia – NG/FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Calpine Blue Heron, FL	10 – NG (24-hr CEMS) 17 – NG (DB&PA)	1.2 – NG 6.6 – NG (DB&PA)	31.9 lb/hr – NG (DB&PA) 10 percent Opacity 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu –(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Alabama Power Theo	~36 – CT & DB	~12.5 CT & DB		Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu –(CT/DB) 10% Opacity	Clean Fuels Good Combustion

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All of the projects listed above control SO₂ and sulfuric acid mist by limiting the sulfur content of the fuel. In every case, pipeline quality natural gas is used and has a sulfur content less than 2 grains per 100 cubic feet. In some cases, the limits are even lower or are expressed in different terms. However all ultimately rely on a fairly uniform gas distribution network and have very little flexibility in actually controlling sulfur content. Similarly, emissions of these two pollutants are controlled by using 0.05 percent sulfur distillate fuel oil.

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

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Total annual emissions of NO_x for the project are expected to be approximately 365 tons per year. Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_x Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

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

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

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

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

Fuel NO_x is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as the El Paso Belle Glade Energy Center.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O₂). The Department estimates uncontrolled

Gas Turbine - Hot Gas Path Parts

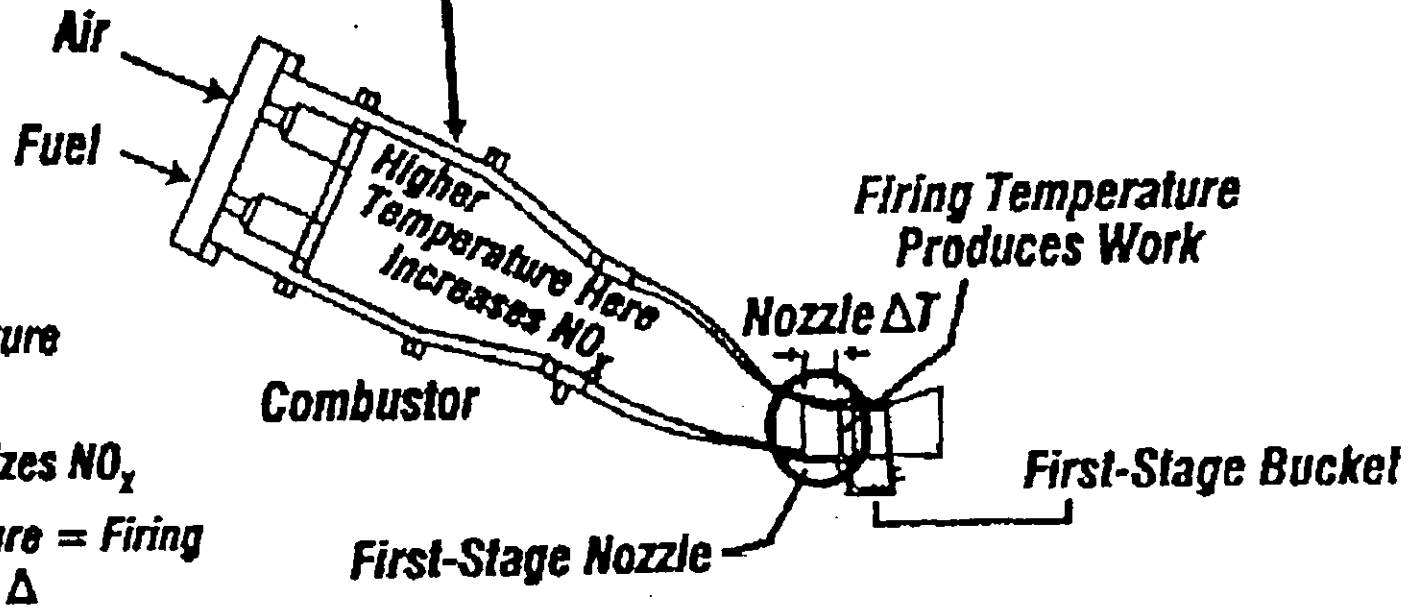
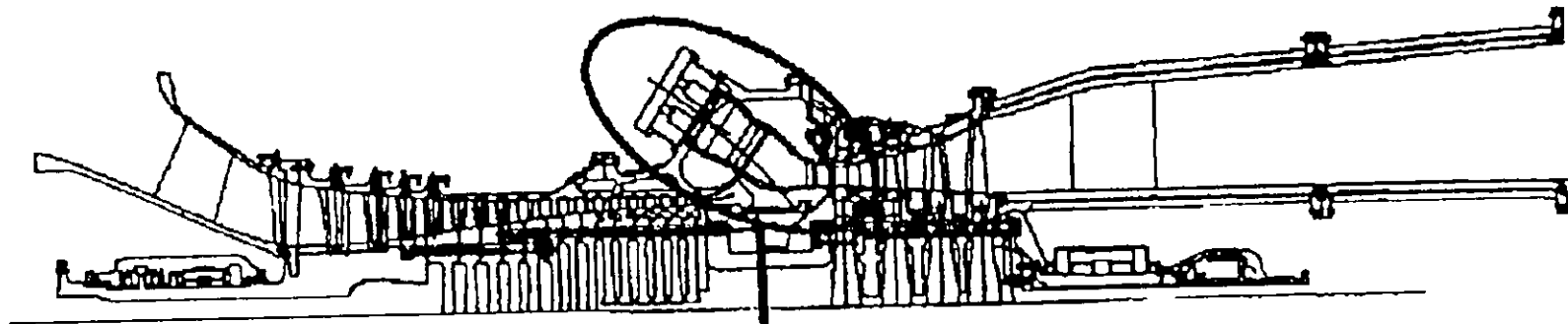


Figure 1 – Relation Between Flame Temperature and Firing Temperature

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emissions at approximately 200 ppmvd @15% O₂ for each turbine of the El Paso 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: Dry Low NO_x (DLN)

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

The above principle is 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 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.¹ The DLN-2.6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_x while burning natural gas although the permit limit is 12 ppmvd. The results are all superior to the emission characteristics given in Figure 3.

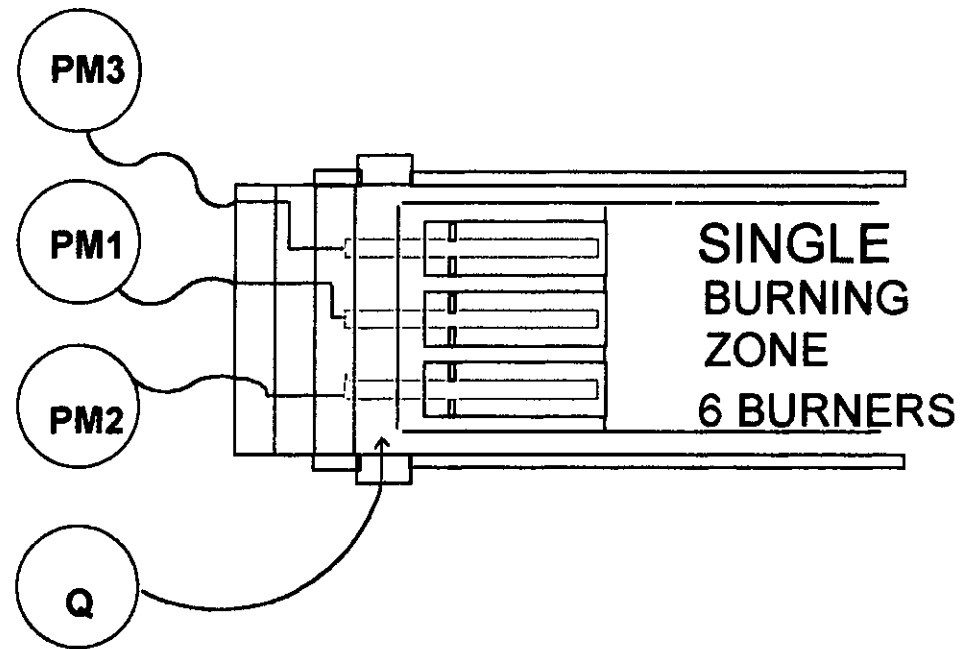
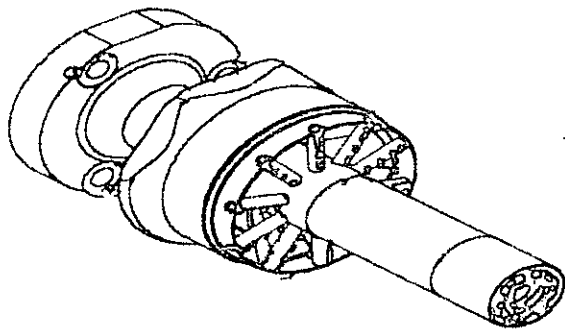
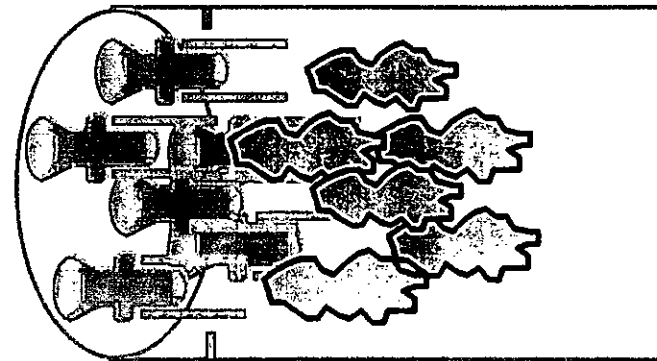
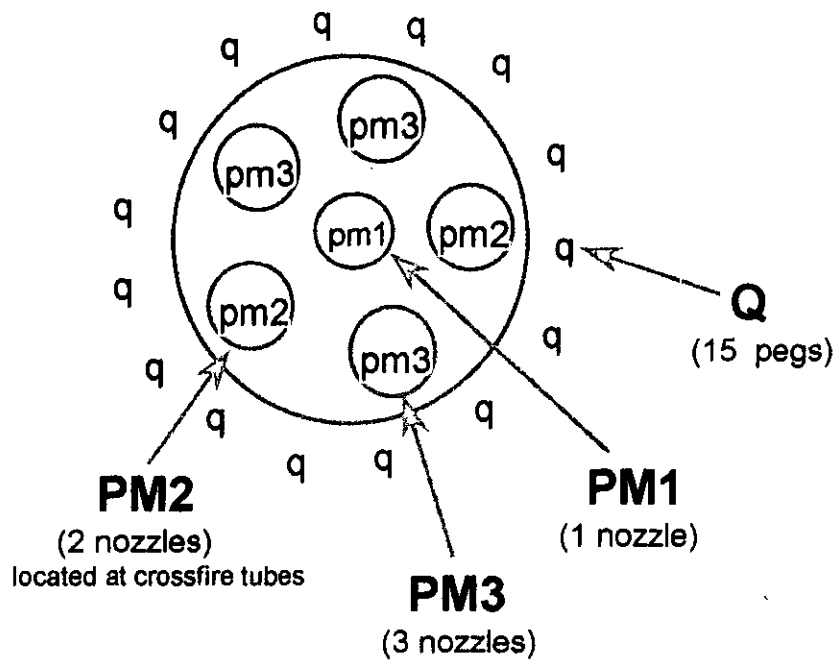


Figure 2 - DLN2.6 Fuel Nozzle Arrangement

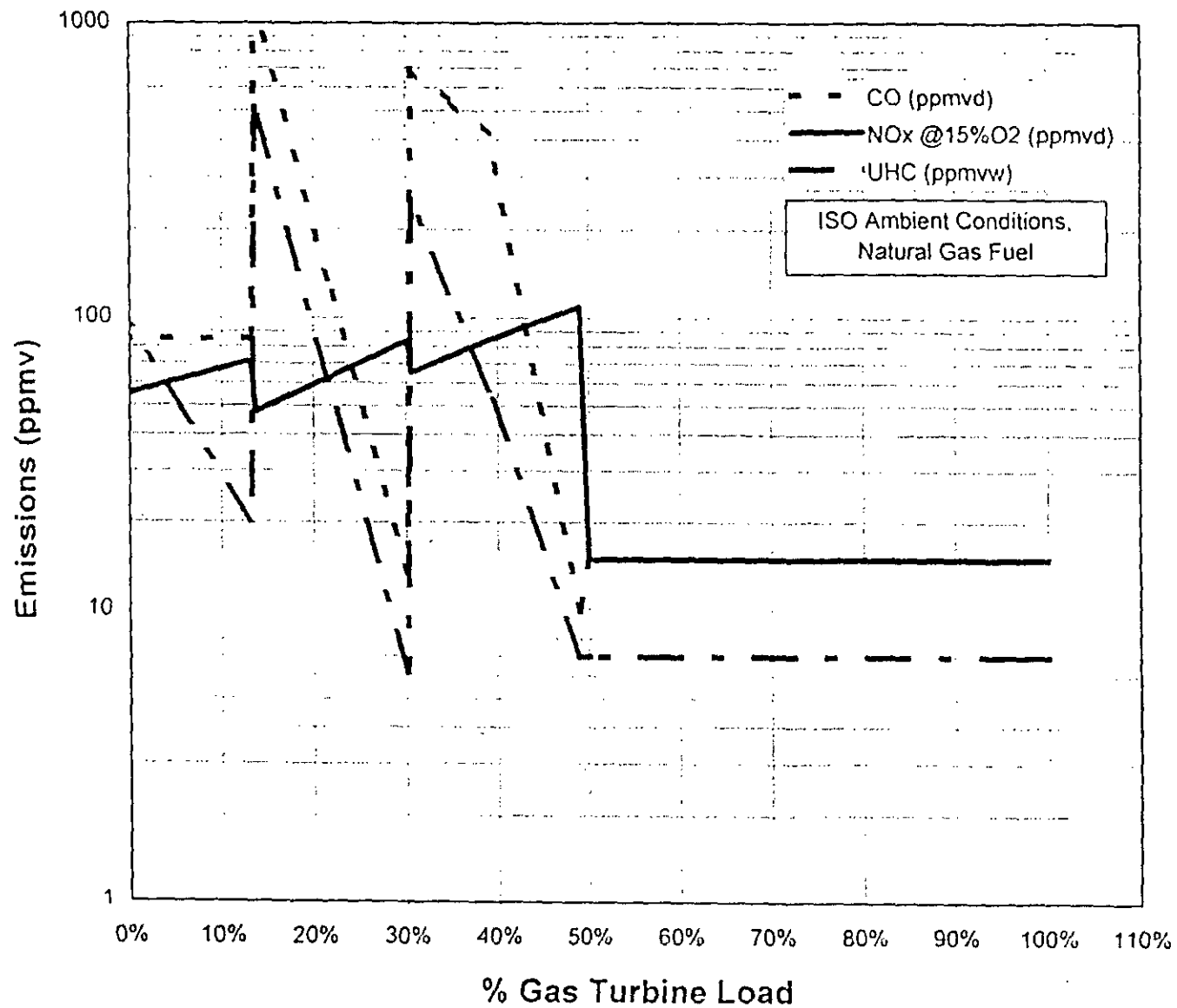


Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine (Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_x)

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Percent of Full Load	NO _x (ppmvd @15% O ₂)	CO (ppmvd)
70	7.2	
80	6.1	
90	6.6	
100	8.7	0.85
Limit	12	25

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.² The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_x while burning natural gas although the permit limit is 10.5 ppmvd. Again, 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

Recent conversations with other operators indicate that the "Dry Low NO_x" characteristics extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE.³

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 4 from an EPRI report.⁴ 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 4.

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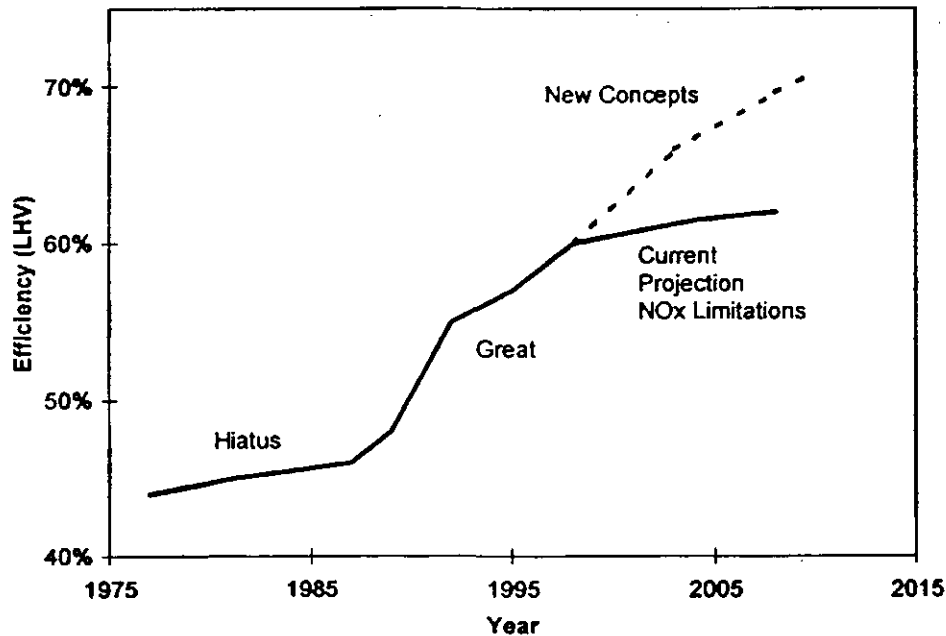


Figure 4 – Efficiency Increases in Combustion Turbines

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 El Paso. 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 .⁵ 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 production) followed by flameless catalytic combustion to further attenuate NO_x formation.

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In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.⁶ 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 that 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.⁷ 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: SCR

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

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

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

Kissimmee Utilities Authority (KUA) will install SCR at the Cane Island Unit 3 project. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued recently to Competitive Power Ventures (CPV), Calpine, Florida Power Corporation, and Tampa Electric to achieve 3.5 ppmvd. More recently a permit was issued to CPV for its Pierce, Polk County project with a limit of 2.5 ppmvd @15% O₂ by SCR.

Figure 5 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 6 is a photograph of FPC Hines Energy Complex. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

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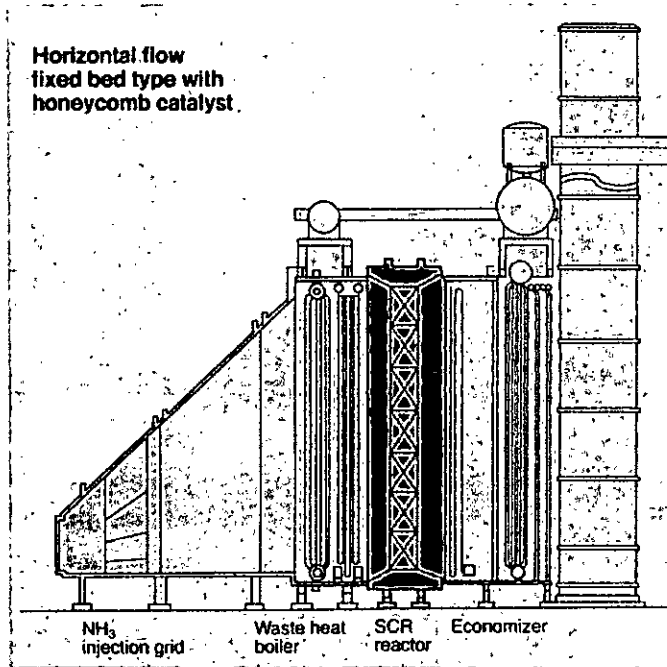


Figure 5 – SCR System within HRSG

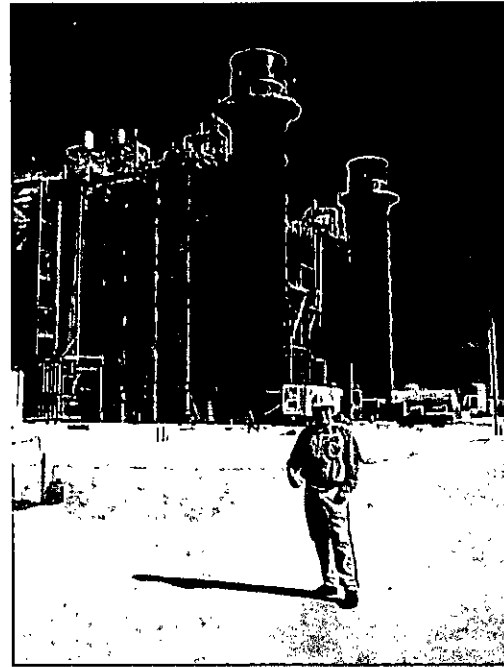


Figure 6 – FPC Hines Power Block I

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) 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_xTM

SCONO_xTM 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.⁸

California regulators and industry sources stated that the first 250 MW block to install SCONO_xTM will be at PG&E's La Paloma Plant near Bakersfield.⁹ The overall project includes several more 250 MW blocks with SCR for control.¹⁰ 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_xTM.

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SCONO_xTM 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_xTM process include in addition to the reduction of NO_x, the elimination of ammonia and the control of VOC and CO emissions. SCONO_xTM has not been applied on any major sources in ozone attainment areas.

Recently EPA Region IX acknowledged that SCONO_xTM was demonstrated in practice to achieve 2.0 ppmv NO_x.¹¹ 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 ppmvd. More recently, Goal Line announced that SCONO_xTM has in practice achieved emissions of 1.3 ppmvd.¹²

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."¹³

SCONO_x requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for the simple cycle units proposed in this application.

REVIEW OF SULFUR DIOXIDE (SO₂) AND SULFURIC ACID MIST (SAM)

SO₂ 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 SO₂ from natural gas and fuel oil-fired combustion turbines.

For this project, the applicant has proposed as BACT the use of pipeline natural gas. The applicant estimated total emissions for the project at 69 TPY of SO₂ and 10 TPY of SAM. The Department expects the emissions to be lower because the typical natural gas in Florida contains less than the 1.5 grains of sulfur per 100 standard cubic feet (gr S/100scf) specification proposed by El Paso. This value is well below the "default" maximum value of 20 gr S/100 scf characteristic of natural gas, but is still high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM₁₀) 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 (PM₁₀).

Natural gas will be the only fuel fired and is efficiently combusted in gas turbines. Clean 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.

A technology review indicated that the top control option for PM/PM₁₀ is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM₁₀ for the project are expected to be approximately 181 tons per year (including filterable and condensable particulate fractions).

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Drift eliminators will be installed on the freshwater mechanical draft cooling tower to reduce PM/PM₁₀. The drift eliminators proposed by El Paso will reduce drift to 0.0005 percent of the circulating water flow rate. This is equivalent to approximately 1 and 1.6 tons per year of PM₁₀ and PM respectively.

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.

CO is emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO. There is a great deal of uncertainty regarding actual CO emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions have actually been reported from several facilities without use of oxidation catalyst. For example, although Westinghouse does not offer a single digit CO guarantee on the 501F, the units installed at the FPC Hines Energy Complex achieved CO emissions in the range of 1-3 ppmvd on both gas and fuel oil at full load.¹⁴ As previously discussed, GE 7FA units achieved similar results when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent.

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

One alternative is to complete the combustion by installation of an oxidation catalyst. Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd.

A recent permit was issued by the Bay Area AQMD in California for the Metcalf Energy Center. The limit for CO from a Siemens-Westinghouse 501F gas turbine is 6 ppmvd (at full load). No Catalyst is required. However it is doubtful that performance can be maintained at low load.

A recent draft permit was issued by the Department that limits CO to 3.5 ppmvd on a Mitsubishi 501F combustion turbine.¹⁵ Enron will install an oxidation catalyst at Ft. Pierce in order to avoid high CO emissions at low load (<70 percent of full load). This results in the ability to obtain a guarantee for the low permitted level at full load. This would not have been a concern if the units were GE7FAs for the reasons discussed above.

The limit proposed by El Paso for the Belle Glade Energy Center under normal operation is 7.4 ppmvd @15% O₂ at full load. This is consistent with the description of the DLN-2.6 technology. The expected results are 1-2 ppmvd and are actually better than what the Enron and Metcalf projects will likely achieve across the 50-100 percent operating range.

A higher limit of 12 ppmvd @15% O₂ is proposed during power augmentation for the combined cycle unit. Under this mode, steam from the HRSG is re-injected into the combustors to boost power production. One consequence is that CO emissions can increase.

Total annual emissions of CO for the project are expected to be approximately 349 tons per year.

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REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limit proposed by El Paso for this project is 1.4 ppmvd @ 15% O₂ for all modes of operation. According to GE (and Department data), VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.¹⁶

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

BACKGROUND ON PROPOSED GAS TURBINE

El Paso plans to install three nominal 175-MW General Electric 7FA gas turbines, one of which will operate in combined cycle mode. Per the discussion above, such units are capable of achieving and have achieved (with DLN and SCR technology) all of the emission limits proposed by El Paso as BACT.

The GE Speedtronic™ Mark VI Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include fuel control 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 VI also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_x values.¹⁷

STARTUP AND SHUTDOWN EMISSIONS

The Department defines "Startup" as follows¹⁸:

"Startup" - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

The Department permits excess emissions during startup and shut down as follows:¹⁹

Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

The Department defines "Excess Emissions" as follows:²⁰

"Excess Emissions" - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, sootblowing, load changing or malfunction.

The U.S. EPA Region IV office recently recommended that the Department consider establishment of establishment of startup and shutdown BACT for CO and NO_x such as mass emission limits (e.g., pounds of emissions in any 24-hour period) that include startup and

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shutdown emissions, or future emission limits derived from monitoring results during the first few months of commercial operation.”²¹

The Department reviewed a number of emission estimates and permit conditions addressing startup and shutdowns for projects in California, Georgia, Washington, and Mississippi and has determined that much of the information is based on estimates that are very difficult to verify.

A review of published General Electric information indicates that features are incorporated into the design of the DLN-2.6 technology specifically aimed at minimizing emissions. One of the key elements was to incorporate lean pre-mixed burning while operating the unit in low load and startup.²² This is in contrast with the previous DLN-2.0 technology that relied on diffusion mode combustion at four of the burners in each combustor during startup and low load operation.

During startup, NO_x concentrations in the exhaust of a simple cycle unit are greater than during full-load operation. The concentrations are estimated at 20 to 80 ppmvd @15% O₂ during the first 10 minutes or so after the unit is actually firing fuel. This occurs while only one to four of the six nozzles shown in Figure 2 are in operation on each combustor.

Within the following 5 minutes, the unit switches to Mode 5 (or 5 Q), during which NO_x concentrations are typically less than 10 ppmvd even though the unit is not yet at full load.²³ The Low-NO_x modes occurs when at least the five outer nozzles are in operation.

Given the short duration and the relatively low exhaust rate (and load) during the high pollutant concentration phases of simple cycle startup, the Department believes that the NO_x emissions during the first hour of startup and operation will be approximately equal to emissions during an hour of full load steady-state operation. Arguments covering shutdown are similar and the time is more compressed so that the Department believes the conclusion is the same for startup as for shutdown.

NO_x concentrations in the exhaust during startup and shutdown will be less than the New Source Performance Standard limit of approximately 110 ppmvd @15% O₂ applicable to F-Class turbines. A simple cycle unit will typically have one startup and shutdown every day that it is used.

For a combined cycle cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated up. During a period of approximately 3 hours emissions will be roughly 60 to 80 ppmvd NO_x @15% O₂. Once the HRSG is heated sufficiently, the ammonia system is turned on to abate emissions.

While emissions during the first two or three hours may be greater than during full load steady state operation, such startups are infrequent. Also, it is noted that such a cold startup would be preceded by a shutdown of at least 72 hours. Therefore the startup emissions would not cause annual emissions greater than the potential-to-emit under continuous operation.

The combined cycle startup scenario described above can be modified by use of a bypass stack and damper.²⁴ Under this scenario, the steam cycle can be slowly brought up to load while the gas turbine reaches full load as fast as it would under simple cycle mode. The exhaust gas can be modulated in such a fashion that the HRSG and steam turbine are ramped up slowly in accordance with their respective specifications. At the same time, the gas turbine will quickly accelerate to the DLN modes (5Q or 6Q) thus minimizing emissions. In this manner the startup NO_x and CO

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concentrations are reduced to the values observed during simple cycle startup. Thereafter the unit will exhibit the same characteristics (for about three hours) as a simple cycle unit in steady-state operation until the ammonia system is actuated.

Implementation of bypass modulation requires an additional stack and design features to minimize stratification and uneven heating of boiler tube bundles in the HRSG.

The Department is gathering information from recently commissioned 7FA units to more accurately estimate startup emissions for NO_x and address carbon monoxide too.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the El Paso project assuming full load. Values for NO_x and CO are corrected to 15% O₂ 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	DEPARTMENT'S PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO _x Combustors Selective Catalytic Reduction	9 ppmvd @ 15% O ₂ (simple cycle units) 2.5 ppmvd @ 15% O ₂ (combined cycle) 5 ppm ammonia slip from combined cycle unit
Particulate Matter	Pipeline Natural Gas Combustion Controls	20 pounds per hour (filterable plus condensable) 0.0005 % drift of circulating rate – cooling tower
Visible Emissions	As Above	10 Percent (surrogate for PM ₁₀)
Carbon Monoxide	As Above	7.4 ppmvd @15% O ₂ (full load, simple or combined) 12 ppmvd @15% O ₂ (combined-steam augmentation)
Sulfur Oxides	As Above	1.5 grain sulfur/100 std cubic feet

RATIONALE FOR DEPARTMENT'S DETERMINATION

- Certain control options are feasible only for combined cycle units are not applicable to simple cycle operation. This rules out Low Temperature (conventional) SCR, and SCONOX. XONON is claimed to be available for F Class gas-fired projects.
- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are high temperature (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.

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- The levelized costs of NO_x removal by Hot SCR for the El Paso project were estimated by El Paso at \$22,052 per ton assuming 5,000 hours of operation. The estimates are based on reducing NO_x emissions from 9 to 3.5 ppmvd @15% O₂.
- The Department does not accept the precise Hot SCR cost calculations presented by El Paso and considers them on the high end. But even at half the cost estimated by El Paso, the Department would agree that Hot SCR is not be cost-effective for this project.
- XONON is rejected because it has not yet been demonstrated in large combustion turbines and is likely to be even less cost-effective than Hot SCR.
- The Department accepts El Paso's BACT proposal of 9 ppmvd NO_x @15% O₂ for the simple cycle units and exclusive use of natural gas. The Department notes that data from the City of Tallahassee and TECO demonstrate that the GE 7FA units actually achieve 6 to 8 ppmvd @15% O₂.
- The proposed BACT limit of 9 ppmvd for the simple cycle units is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The Department's overall BACT determination for the simple cycle units is equivalent to approximately 0.35 lb of NO_x per megawatt-hour (lb/MWH) 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 (fuel independent) limit of 1.6 lb/MW-hr.
- The Department will limit operation of the two units to an average of 5,000 hours per year per simple cycle unit. The Department will further limit the operation of each and every individual unit to the fuel-equivalent of 5,000 full load hours of operation. The purpose is to maintain the conclusion regarding cost-effectiveness under intermittent duty operation.
- Although startup and shutdown emissions are generally exempt, emissions during startup and shutdown are less than the NSPS limit of 110 ppmvd @15% O₂ (that applies during steady-state operation).
- The Department does not yet have sufficient information from field experience to set start-up and shutdown emissions limits. However, the modes that give rise to high NO_x concentration have been identified. The Department will therefore set a work practices standard as BACT.
- The Work Practice BACT for simple cycle startup is that the unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. The shutdown case is trivial.
- The Lowest Achievable Emission Rate (LAER) for a combined cycle unit is approximately 2 ppmvd NO_x at 15 percent oxygen (@15% O₂) while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line, has requested recognition of a 1.3 ppmvd NO_x value as *achieved in practice*.
- There are several projects for large turbines in Massachusetts, Connecticut, New York, and California requiring SCR with a NO_x emission limit of 2 ppmvd @15% O₂.
- The "Top" technology in a top/down analysis for a combined cycle unit will achieve approximately 2 ppmvd @15% O₂ by either SCONO_x or SCR.

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- El Paso estimated the cost effectiveness of $SCONO_x$ at \$24,187 per ton of NO_x removed. The Department does not necessarily accept the precise $SCONO_x$ cost calculations presented by El Paso. However, even at half the cost estimated by El Paso, the Department agrees that $SCONO_x$ would not be cost-effective for this project.
- El Paso estimated the cost-effectiveness of conventional (cold temperature) SCR at \$3,535 per ton of NO_x while reducing emissions from 9 to 3.5 ppmvd @15% O_2 . The Department accepts El Paso's estimate and believes this cost-effectiveness can be maintained while achieving an NO_x emission rate of 2.5 ppmvd @15% O_2 .
- The National Park Service advised in its review of the application that BACT determinations of 2.5 ppmvd NO_x @15% O_2 have recently been issued for combined cycle projects in Maine and Washington. The Park Service also agreed that 9 ppmvd represents BACT for simple cycle units.²⁵
- The Department concludes that 2.5 ppmvd NO_x @15% O_2 (with 5 ppmvd ammonia slip) while firing natural gas in a combined cycle unit constitutes BACT. This value for the conventional SCR option takes into consideration the measurement uncertainties at low emission rates and minimizes particulate emissions due to ammonia emissions.
- The effects of aqueous ammonia use and ammonia slip are not unacceptable. The North Broward Resource Recovery Facility across the street from the proposed site also uses aqueous ammonia for NO_x control.
- The Department's overall BACT determination for the combined cycle unit is less than 0.07 lb of NO_x per megawatt-hour (lb/MWH) by Dry Low NO_x .
- The Work Practice BACT for combined cycle startup is that the combustion turbine will start up and operate as a simple cycle unit and modulate exhaust to the HRSG. This requires installation of a bypass stack and damper. The unit shall reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. Ammonia injection will be practiced within three hours after gas turbine ignition and crossfire.
- The Department does not have a cost estimate for the additional stack and design requirements, but believes the additional power and flexibility offered by full load simple cycle operation during the cold startup of the steam cycle more than compensates for the additional costs.
- The applicant estimates VOC emissions of 1.4 ppmvd @15% O_2 (or less) for all firing modes. These levels will not trigger PSD or a requirement for a BACT determination.
- El Paso estimated levelized costs at \$9,000 per ton to reduce emissions at the simple cycle units from about 7.4 to 0.7 ppmvd CO @15% O_2 . The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- In view of the performance of GE 7FA units without add-on control (~ 0 - 4 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective for the simple cycle units based on *actual* emissions and appears to not be cost-effective based on permitted emissions.

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- El Paso estimated levelized costs for CO catalyst control at \$2,475 to reduce emissions from 11.7 to 1.2 ppmvd @15% O₂ for the combined cycle unit operating in power augmentation mode. In view of the performance of GE 7FA units cited in the discussion above (Tallahassee and TECO Polk Power data) without add-on control (~ 1 ppmvd), it appears to the Department that oxidation catalyst costs are substantially biased to the low side based on *actual* emissions.
- The Department will set CO limits achievable by good combustion as 7.4 ppmvd @15% O₂ at full load and 8 ppmvd @15% O₂ over the full operational range for simple cycle and combined cycle operation. Additionally, the Department will set a limit of 12 ppmvd @15% O₂ for the combined cycle unit during power augmentation.
- The CO limits of 8 ppmvd @15% O₂ under normal combined cycle operation and 12 ppmvd @15% O₂ under power augmentation are low and within the range of recent BACT determinations for combustion turbines in the Southeast.
- The Department will set CO limits reflecting the "new and clean test" guarantees rather than actual performance because GE will not (yet) guarantee the lower values. 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. The Department will also limit the extent to which El Paso can operate in power augmentation mode to 2000 hours unless El Paso installs oxidation catalyst or proves that actual performance is much better than guaranteed (thus rendering control not cost effective).
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_x, SO₂, or PM₁₀.
- There is no benefit in penalizing the applicant with a lower limit at this time just because the performance at another site was far better than guaranteed or expected. The applicant will be required to install a continuous CO monitor on the combined cycle unit. It is expected that data from continuous measurement will conclusively show that oxidation catalyst is not needed and is not cost effective for this project.
- BACT for sulfur oxides is the exclusive use of natural gas with a specification of 1.5 grains per 100 standard cubic feet. Pipeline quality natural gas in Florida contains less than this value.
- BACT for PM₁₀ was determined to be good combustion practices consisting of: inlet air filtering, exclusive use of pipeline natural gas, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limit for PM₁₀ will be set at 11 pounds per hour. This value is based on filterable fraction only per the Department's definition of PM/PM₁₀. Expected particulate emissions based on filterable plus condensable particulate matter are 20 pounds per hour.
- PM₁₀ emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.
- BACT for the Cooling Tower was determined to be use of fresh water and drift eliminators designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. A lower drift rate would be reasonable for project where reused wastewater is the cooling medium.

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POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions (initial, annual)	Method 9
PM/PM ₁₀ (initial)	Method 5 (Front-half catch)
VOC	Method 25A corrected by methane from Method 18
CTM-027(initial, quarterly, annual)	Procedure for Collection and Analysis of Ammonia in Stationary Sources
SO ₂ /SAM	Record keeping for the sulfur content of fuels delivered to the site
CO (initial, annual, CEMS)	Method 10; CO-CEMS (continuous 3-hr block average)
NO _x (continuous 24-hr)	NO _x CEMS, O ₂ or CO ₂ diluent monitor, and flow device as needed
NO _x (initial and annual)	Annual Method 20 (can use RATA if at capacity); Method 7E

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:

Approved By:

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

 Howard L. Rhodes, Director
 Division of Air Resources Management

 Date

 Date

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