Adams, Patty

From: Quillian, Ann [Ann.Quillian@pgnmail.com]
Sent: Monday, December 18, 2006 8:12 AM
To: Harvey, Mary
Cc: Adams, Patty; Linero, Alvaro; Jackson, Rufus
Subject: RE: Bartow Documents #1030011-010-AC-DRAFT

Received your e-mail along with the five .pdf attachments. Thanks for your help.

Ann Q.

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, December 15, 2006 3:19 PM
To: Quillian, Ann
Cc: Adams, Patty; Linero, Alvaro
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

Ann, I have already emailed Rufus another copy earlier today. He has not responded back to me yet. I hope he received these documents.

Thanks,
Mary

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Friday, December 15, 2006 9:07 AM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Hessling, Peter A [mailto:phesslin@co.pinellas.fl.us]
Sent: Friday, December 15, 2006 7:31 AM
To: Harvey, Mary
Subject: Read: Bartow Documents #1030011-010-AC-DRAFT

Your message

To: phesslin@co.pinellas.fl.us
Subject:

was read on 12/15/2006 7:31 AM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 5:37 PM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Thursday, December 14, 2006 4:47 PM
To: Harvey, Mary
Subject: Bartow Documents #1030011-010-AC-DRAFT

Return Receipt

Your document:	Bartow Documents #1030011-010-AC-DRAFT
was received by:	Dee Morse/DENVER/NPS
at:	12/14/2006 02:45:37 PM

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 5:37 PM
To: Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Nasca, Mara
Sent: Thursday, December 14, 2006 5:05 PM
To: Harvey, Mary
Subject: Read: Bartow Documents #1030011-010-AC-DRAFT

Your message

To:	'rufus.jackson@pgnmail.com'; 'sosbourn@golder.com'; 'Ann.Quillian@pgnmail.com'; 'Dee_Morse@nps.gov'; 'meredith_bond@fws.gov'; 'Little.James@epamail.epa.gov'; Nasca, Mara; 'mayor@stpete.org'; 'sspratt@pinellascounty.org'; 'phesslin@pinellascounty.org'
Cc:	Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject:	Bartow Documents #1030011-010-AC-DRAFT
Sent:	12/14/2006 4:24 PM

was read on 12/14/2006 5:05 PM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 5:36 PM
To: Linero, Alvaro; Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT
Attachments: 1030011.010.AC.D_pdf.zip

From: Nasca, Mara
Sent: Thursday, December 14, 2006 5:05 PM
To: Prickett, Patricia; Harvey, Mary
Cc: Zhang-Torres
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Harvey, Mary
Sent: Thursday, December 14, 2006 4:24 PM
To: 'rufus.jackson@pgnmail.com'; 'sosbourn@golder.com'; 'Ann.Quillian@pgnmail.com'; 'Dee_Morse@nps.gov'; 'meredith_bond@fws.gov'; 'Little.James@epamail.epa.gov'; Nasca, Mara; 'mayor@stpete.org'; 'sspratt@pinellascounty.org'; 'phesslin@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Bartow Documents #1030011-010-AC-DRAFT

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 4:31 PM
To: Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Osbourn, Scott [mailto:Scott_Osbourn@golder.com]
Sent: Thursday, December 14, 2006 4:29 PM
Subject: Read: Bartow Documents #1030011-010-AC-DRAFT

Your message

To: Scott_Osbourn@golder.com
Subject:

was read on 12/14/2006 4:29 PM.

Adams, Patty

From: Harvey, Mary

Sent: Thursday, December 14, 2006 4:24 PM

To: 'rufus.jackson@pgnmail.com'; 'sosbourn@golder.com'; 'Ann.Quillian@pgnmail.com'; 'Dee_Morse@nps.gov'; 'meredith_bond@fws.gov'; 'Little.James@epamail.epa.gov'; Nasca, Mara; 'mayor@stpete.org'; 'sspratt@pinellascounty.org'; 'phesslin@pinellascounty.org'

Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria

Subject: Bartow Documents #1030011-010-AC-DRAFT

Attachments: 1030011.010.AC.D_pdf.zip

Dear Sir/Madam:

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The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 21, 2006 10:31 AM
To: Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

-----Original Message-----
From: Little.James@epamail.epa.gov [mailto:Little.James@epamail.epa.gov]
Sent: Wednesday, December 20, 2006 4:36 PM
To: Harvey, Mary
Subject: Re: Bartow Documents #1030011-010-AC-DRAFT

I received them. Thanks.

Jim

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

12/15/2006 11:12 AM

To
James Little/R4/USEPA/US@EPA

cc
"Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>, "Adams, Patty" <Patty.Adams@dep.state.fl.us>

Subject
Bartow Documents #1030011-010-AC-DRAFT

As usual, we can not receive files with a .zip extension.

Jim Little - U.S. EPA Region 4
(404) 562-9118

Jim, I hope you got these files. Please email me back to let me know the if you received them this time.

Thanks,

Mary

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,
DEP, Bureau of Air Regulation

[attachment "APP381- #1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US] [attachment "INTENT381 - #1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US] [attachment "PERMIT381 - #1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US] [attachment "Signed Documents #1030011-010-AC - DRAFT.pdf" deleted by James Little/R4/USEPA/US] [attachment "TECHNICAL381 - 1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US]

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (850) 488-0114 FAX: (850) 922-6979

Colleen M. Castille
Secretary

December 13, 2006

Electrically Sent – Received Receipt Requested

Mr. Rufus Jackson
Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 32701

Re: P.L. Bartow Plant Repowering Project
DEP File No.: 1030011-010-AC (PSD-FL-381)

Dear Mr. Jackson:

Enclosed are documents indicating the Department's preliminary determination to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Progress Energy Florida for the construction of a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit at the P.L. Bartow Plant located at 1601 Weedon Island Drive in St. Petersburg. The project includes and requires the shutdown of the three existing residual oil-fueled steam electrical generating units. The documents include: the Intent to Issue Air Construction Permit; the Public Notice of Intent to Issue Air Construction Permit; the Department's Technical Evaluation and Preliminary Determination including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 (meteorologist), Teresa Heron at 850/921-9529 (review engineer) or Mr. Linero at 850/921-9523.

Sincerely,

Trina Vielhauer, Chief
Bureau of Air Regulation

AAL/th

Enclosures

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.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, 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 the Draft Air Construction Permit) and all copies were sent electronically (with Received Receipt) before the close of business on 12/14/06 to the persons listed:

Rufus Jackson, PEF: rufus.jackson@pgnmail.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Ann Quillian, P.E., PEF: ann.quillian@pgnmail.com
Dee Morse, NPS: dee_morse@nps.gov
Meredith Bond, U.S. FWS: meredith_bond@fws.gov
Jim Little, EPA: little.james@epa.gov
Mara Nasca, DEPSWD: mara.nasca@dep.state.fl.us
Mayor, City of St. Petersburg: mayor@stpete.org
Administrator, Pinellas County: sspratt@pinellascounty.org
Peter Hessling, PCDEM: phesslin@pinellascounty.org

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

Mary D. Harvey 12/14/06

(Clerk) (Date)

In the Matter of an
Application for Air Permit by:

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

DEP File No.: 1030011-010-AC
P.L. Bartow Power Plant
Repowering Project
Pinellas County

Authorized Representative: Mr. Rufus Jackson

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of Draft Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Florida Power Corporation dba Progress Energy Florida, applied on July 31, 2006 to the Department for an air construction permit pursuant to the PSD rules to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit at the P.L. Bartow Power Plant on Weedon Island in Pinellas County. The project includes and requires the shutdown of three existing residual oil-fueled steam electrical generating units. The project is in effect a plant repowering.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), 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 is required.

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 (Notice). 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. Pursuant to Rule 62-17.135(1)(c), F.A.C. the applicant shall have published in the appropriate newspapers the Notice no later than 10 days after the preliminary determination has been issued. 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. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If the Department determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly at http://faw.dos.state.fl.us and in a newspaper of general circulation in the area affected by the permitting action. 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

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1030011-010-AC (PSD-FL-381)

Florida Power Corporation dba Progress Energy Florida, Inc.
P.L. Bartow Power Plant Repowering Project
Pinellas County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the Rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Progress Energy Florida (PEF). The permit is to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle combustion turbine-electrical generator while permanently shutting down three residual oil-fueled steam electrical generating units at the P.L. Bartow Power Plant on Weedon Island in St. Petersburg, Pinellas County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The applicant's corporate address is Florida Power Corporation dba Progress Energy Florida, Inc., 100 Central Avenue, St. Petersburg, Florida 33701.

The combined cycle unit will consist of: four Siemens SGT6-5000F gas-fueled combustion turbine-electrical generators (CTGs) with Dry Low NO_X combustors capable of operating in simple cycle or combined cycle modes; four duct-fired heat recovery steam generators (HRSGs); one steam turbine-electrical generator (STG); eight 120-feet exhaust stacks, i.e. two per CTG. Additional equipment includes: a small auxiliary boiler; five gas heaters; two nominal 3.5 million gallon storage tanks; and other associated support equipment.

The simple cycle unit will be a single Siemens SGT6-5000F gas-fueled CTG with a single stack. The combined capacity of the two units is approximately 1,475 megawatts (MW) when referenced to standard (ISO) conditions. Approximately 420 MW of the total will be from the new STG.

The combined cycle unit and the simple cycle unit will each be permitted to operate continuously while firing inherently clean natural gas. Low sulfur (0.05 percent sulfur) distillate fuel oil will be allowed as backup fuel for 1000 hours per year per each of five CTGs. The gas-fueled duct burner within each of four HRSGs may operate 2,434 hours per year and each CTG may be operated in power (steam) augmentation mode for 1,688 hours per year.

The boilers and stacks associated with existing residual oil-fired steam electrical generating Units 1, 2, and 3 will be permanently shut down. These units have STGs with a total capacity of approximately 472 MW. The installation of the combined cycle unit and the simple cycle unit constitutes a plant repowering project.

When firing natural gas, nitrogen oxides (NO_X) emissions from all five CTGs will be limited to 15 parts per million by volume at 15 percent oxygen (ppmvd) as required by 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. The NO_X limit is 42 ppmvd by wet injection when using backup low sulfur (0.05%) fuel oil. The HRSGs within the combined cycle unit will be further equipped with selective catalytic reduction (SCR) ammonia injection systems that provide PEF with the option of further controlling NO_X to generate allowances under the Clean Air Interstate Rule (CAIR).

The Department's proposed BACT CO emission limits for each of the five CGTs is 4.1 ppmvd when operating on natural gas and 8.0 ppmvd when operating on fuel oil. CO limits of 8.0 ppmvd on a 24-hour basis and 6 ppmvd on a 12-month basis also apply to the four CGT/HRSG sets when operated in combined cycle mode. VOC emissions from all five CGTs will be limited to 1.2 and 2.8 ppmvd for natural gas and fuel oil firing respectively. CO and NO_X will be continuously monitored when operating the HRSG exhaust stacks and NO_X emissions will be continuously monitored at the simple cycle stacks when in use. PEF has the option to install oxidation catalyst for CO and VOC control particularly if significant low load combined cycle operation is practiced.

There will be very substantial decreases in the regulated air pollutants except for CO and VOC. The maximum potential annual emissions from the new units in tons per year are summarized below for comparison with recent annual emissions from the three units slated for shut down.

Pollutants	Baseline Emissions Units 1,2, 3	Future Emissions New Units	Net Increase (decrease)
PM/PM_{10}	804/559	413/413	(391/146)
SAM	423	72	(351)
SO_2	24,816	466	(24,350)
NO_x	4,043	3,191	(852)
VOC	57	145	88
CO	367	938	571

PEF may operate any two of the five CGTs in simple cycle mode prior to the permanent shutdown of Units 1, 2 and 3. The permit limits this early mode to 1,100 hours (aggregate) for the two CTGs, requires compliance with 40 CFR 60, Subpart KKKK, and caps the emissions of NO_X at 39 tons to be measured by CEMS. These conditions provide assurance that PSD will not be triggered during early operation of two CGTs.

Ambient PSD impact analyses were required only for CO, but were also conducted for NO_X, SO_2, and PM_{10} under the early and permanent operation scenarios. The modeling indicated that CO impacts will be less than the applicable Significant Impact Levels.

(Public Notice to be Published in the Newspaper)

Under the permanent scenario, the lower NO_X emissions will reduce ozone (smog) formation potential and nitrate fallout into local watersheds. The lower PM/PM_{10}, SO_2 and SAM emissions will significantly reduce visible stack emissions, acid smut fallout, and fine particulate generation in the environment. The overall impacts due to the repowering project are all favorable and the net effect is a "creation of available increment."

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If the Department determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly at http://faw.dos.state.fl.us and in a newspaper of general circulation in the area affected by the permitting action. 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 (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

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

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32399-2400 Telephone: 850/488-0114 Fax: 850/922-6979	Department of Environmental Protection Southwest District Office 13501 N, Telecom Parkway Temple Terrace, Florida 33637-0926 Telephone: 813/632-7600 Fax: 813/744-6084	Pinellas County DEM Air Quality Division 300 South Garden Avenue Clearwater, Florida 33756 Telephone: 727/464-4422 Fax: 727/464-4420

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program Administrator, South Permitting Section at the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at http://www.dep.state.fl.us/Air/permitting/construction/bartow.htm

(Public Notice to be Published in the Newspaper)

DRAFT PERMIT

PERMITTEE

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Mr. Rufus Jackson

DEP File No. 1030011-010-AC
Permit No. PSD-FL-381
PEF P.L. Bartow Power Plant
Plant Repowering Project
Pinellas County
SIC No. 4911
Expires: March 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of one nominal 1,280 megawatt (MW) combined cycle unit and one nominal 195 MW simple cycle unit at the Progress Energy Florida (PEF) P.L. Bartow Power Plant located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County.

Three existing fossil fuel fired steam generators designated as Units 1, 2 and 3 with a total nominal capacity of 465 MW will be shut down as part of this project.

The UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations. 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

(DRAFT)

Joseph Kahn, Director
Division of Air Resource
Management

(Date)

FACILITY AND PROJECT DESCRIPTION

Progress Energy Florida operates the Bartow Plant, which is an existing power plant (SIC No. 4911). The plant currently consists of:

- Three fossil fuel fired steam generating units designated as Units 1, 2 and 3 that produce 120, 120 and 225 megawatts (MW) of electrical power respectively;
- Four simple cycle units designated as Gas Combustion Turbine Peaking Units Nos. P-1, P-2, P-3 and P-4 each of which has a nominal capacity of 56 MW; and
- Miscellaneous unregulated/insignificant emissions units including a pipeline heating boiler and relocatable diesel generators that can be located at various PEF power plants.

The project is a plant repowering that includes the construction of a nominal 1,280 MW gas-fired combined cycle unit system ("4-on-1") and a nominal 195 MW gas-fired simple cycle unit. The project includes and requires the shutdown of the three fossil fuel fired steam generating units (Units 1, 2 and 3) resulting in a net decrease in all PSD pollutants except for carbon monoxide (CO) and volatile organic compounds (VOC).

The combined cycle unit system will consist of: four Model SGT6-5000F combustion turbine-electrical generators (CT-electrical generators) with a nominal rating of 215 MW at ISO conditions when practicing power augmentation; four duct-fired heat recovery steam generators (HRSG's) each equipped with a selective catalytic reduction (SCR) reactor and a nominal 500 million Btu per hour (MMBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG). Each CT within the combined cycle unit system will be permitted to operate in simple cycle by directing the exhaust to a bypass stack instead of the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

All CTs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures and wet injection capability for nitrogen oxides control when firing fuel oil or when practicing power augmentation. Each CT will be allowed to fire backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). The new units are designated as Units 4 and Unit 5.

The simple cycle CT-electrical generator will have a nominal rating of 195 MW at ISO conditions and will exhaust through its own 120 foot stack.

Additional ancillary equipment will include: five natural gas fired fuel heaters; two diesel fuel storage tanks; one auxiliary steam boiler; and a diesel fueled emergency fire pump.

This permit authorizes the installation the following new equipment in conjunction with the permanent shutdown of Units 1, 2, and 3.

E.U. ID	Emission Unit Description
009	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
010	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
011	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
012	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
013	Unit 5 – One 195 MW (ISO) Combustion Turbine
014	One Nominal 85,000 lb/hr (99 MMBtu/hr) Auxiliary Boiler
015	Five Nominal 3 MMBtu/hr Gas-fired Process Heaters
016	Two Nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
017	One Nominal 300 horsepower Diesel-fueled Emergency Fire Pump

REGULATORY CLASSIFICATION

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources

The proposed project is subject to the following New Source Performance Standards of 40 CFR 60:

- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. This rule also covers duct burners that are incorporated into combined cycle projects,
- Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boilers, and
- Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Title I, Section 112, Clean Air Act, National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The proposed project is subject to the following National Emissions Standards for Hazardous Air Pollutants:

- 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines.
- 40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, or Institutional Boiler or Process Heater. Applies to auxiliary boiler and gas heaters.

Title I, Part C, Clean Air Act, Prevention of Significant Deterioration (PSD)

The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C.

Title IV, Clean Air Act, Acid Rain Provisions

The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits

The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAP. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Clean Air Interstate Rule (CAIR)

The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting)

The facility was not certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is not subject to Siting because there will be no net increase in steam-generated electrical power. [Design; Letter from Applicant Dated December 19, 2005]

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action:

- Air Construction Permit application received July 31, 2006;
- Department's Request for Additional Information dated August 30, 2006;
- Progress additional information received October 2 and October 26, 2006;
- Intent to Issue, Draft Air Construction Permit, and Technical Evaluation distributed December 13, 2006; and
- Final Determination distributed concurrently with Final Air Construction Permit.

1. Permitting Authority: All documents related to applications for permits to construct, modify, or operate emissions units at this facility 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. Copies of all such related documents shall also be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the Pinellas County Department of Environmental Management Office at 300 South Garden Avenue, Clearwater, Florida 34616.

3. Appendices: The following Appendices are attached as part of this permit: Appendix A (NSPS and NESHAP Subpart A -- Identification of General Provisions); Appendix CF (Citation Format); Appendix GC (General Conditions); and Appendix CC (Common Conditions); Appendix IIII (NSPS Subpart IIII Provisions – Internal Combustion Engines); Appendix KKKK (NSPS Subpart KKKK Provisions - Combustion Turbines and Duct Burners); Appendix YYYY (NESHAP Subpart YYYY Provisions – Combustion Turbines); Appendix BD (BACT Determination); Appendix DDDDD (NESHAP Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater); Appendix Dc (NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units); Appendix XS (Semiannual NSPS Excess Emissions Report).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in general 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 Title 40, Parts 60 and 63 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.]

5. 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.]

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. 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.]

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C. For good cause, the permittee may request that this PSD air construction permit be extended.
[Rules 62-4.070(4), 62-4.080, 62-210.300(1), 62-212.400(12)(a) and 62-212.400(10)(d), F.A.C.]

8. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]
9. 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. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [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 appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]
11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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(3), F.A.C.]

A. Combined Cycle Unit 4 and Simple Cycle Unit 5 (EU-009, 010, 011, 012 and 013)

This section of the permit addresses the following emissions unit.

E.U. ID	Emissions Units Comprising Combined Cycle Unit 4
009	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
010	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
011	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
012	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
013	Unit 5 – One 195 MW (ISO) Combustion Turbine

APPLICABLE STANDARDS AND REGULATIONS

1. PSD Applicability and BACT Determinations: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and Best Available Control Technology (BACT) determinations were made for carbon monoxide (CO) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rules 62-210.200 (Definitions) and 62-212.400, F.A.C.]

   {Permitting Note: The repowering project does not trigger PSD or require a BACT determination for NO_X, SO_2, sulfuric acid mist or PM/PM_{10} because emissions reductions from the permanent shutdown of existing fossil fueled steam generating Units 1, 2 and 3 will exceed emissions increases from the project by values greater than the respective significant emissions rates.}

2. NSPS Requirements: Each CT shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. *Subpart A - General Provisions*, including:

      - 40 CFR 60.7, Notification and Record Keeping
      - 40 CFR 60.8, Performance Tests
      - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
      - 40 CFR 60.12, Circumvention
      - 40 CFR 60.13, Monitoring Requirements
      - 40 CFR 60.19, General Notification and Reporting Requirements

   b. *Subpart KKKK - Standards of Performance for Stationary Combustion Turbines:* These provisions were finalized on July 6, 2006 and include requirements applicable to duct burners located in HRSGs.

3. NESHAP Requirements: The CTs are subject to 40 CFR 63, Subpart A - Identification of General Provisions and 40 CFR 63, Subpart YYYY - National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines.

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines (CTs): The permittee is authorized to install, tune, operate, and maintain five Model SGT6-5000F CT-electrical generator sets. Each CT shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, evaporative inlet air-cooling system and a nominal 120 foot exhaust stack for simple cycle operation.
   [Application No. 1030011-010-AC; Design]

5. Heat Recovery Steam Generators (HRSGs): The permittee is authorized to install, operate, and maintain four new duct-fired HRSGs that recover exhaust heat energy from four of the CTs and deliver steam to a nominal 420 MW steam turbine electrical generator. Each HRSG shall be equipped with a nominal 120 foot

exhaust stack for combined cycle operation. [Application No. 1030011-010-AC; Design]

6. DLN Combustion: The permittee shall install, operate and maintain Dry Low NO_X (DLN) systems to control NO_X emissions from each CT when firing natural gas. Prior to the initial emissions performance tests required for each CT, the DLN combustors and automated combustion turbine control system shall be tuned without a selective catalytic reduction (SCR) system in operation to achieve the permitted CO, VOC and NO_X levels for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 1030011-010-AC; Design]

7. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each CT when firing distillate fuel oil. Prior to the initial emissions performance tests, the water injection system shall be tuned without an SCR system in operation to achieve the NO_X value for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 1030011-010-AC; Design]

8. Selective Catalytic Reduction Systems: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. Operation of the SCR systems is not required when the NO_X emission limits can be met without their use. [Application No. 1030011-010-AC; Design, and 62-210.650 (Circumvention), F.A.C.]

9. Oxidation Catalyst Systems: The permittee shall design and build the project to facilitate future installation of an oxidation catalyst system within each HRSG to control CO and VOC emissions from each of the four CTs/Duct-fired HRSGs comprising the combined cycle unit. The permittee may install oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 18.f. [Rule 62-4.070(3) F.A.C.]

10. Ammonia Storage: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68. [Rule 62-4.070 F.A.C.]

PERFORMANCE RESTRICTIONS

11. Authorized Fuels: Each CT shall fire only natural gas and distillate oil. The maximum sulfur content of natural gas shall not exceed 2.0 grains of sulfur per 100 standard cubic feet of natural gas. The maximum sulfur content of distillate oil shall not exceed 0.05% by weight. [Design; Rules 62-4.070 and 62-210.200 (Definitions – PTE), F.A.C.; 40 CFR 60, Subpart KKKK]

12. Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the lower heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon CT 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(Definitions - PTE), F.A.C.]

13. Permitted Capacity - Duct Burners: The total nominal heat input rate to the duct burners (DBs) located within each HRSG is 500 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(Definitions - PTE), F.A.C.]

14. Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:

    a. *Restriction on SC Operation*:

        - The combined operation of the two CTs shall not exceed 1,100 hours.
        - A NO_X CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_X CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 calendar days of startup of the CTs.
        - Total emissions of NO_X from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_X continuous emissions monitoring systems (CEMS) during the temporary period.
        - Each CT shall be stack tested to demonstrate initial compliance with the applicable Subpart KKKK NO_X emission standard for each fuel to be fired. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Data collected during the above described RATA may be used to satisfy this 60-day test requirement provided all requirements of 40 CFR 60.8 and Subpart KKKK are met.
        - The BACT emissions standards of specific condition 18 do not apply to these CTs prior to Unit 1, 2 and 3 shutdown. Following shutdown of Units 1, 2 and 3 all restrictions of this permit apply, including the BACT limits of specific condition 18.

    b. *Restriction on CC Operation*: No combined cycle operation of any unit is allowed prior to permanent shutdown of Units 1, 2, and 3.

    c. *Monthly Operations Summary*: By the 10th calendar day of each month, the permittee shall record the following in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, NO_X emissions in total tons for the month, and NO_X emissions in total tons for the described restricted period 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. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.

    {Permitting note: The limitation on total NO_X emissions and adherence to the emissions standards in Specific Conditions 18, 19 and 20 along with the compliance and recordkeeping requirements of this condition will effectively ensure that emissions increases of all PSD pollutants from the selected CTs operated in SC mode prior to Unit 1, 2 and 3 shutdown will be less than their respective Significant Emissions Rates per Rule 62-210.200 (Definitions-SER), F.A.C.}

    [Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(12)(PSD Avoidance), F.A.C.; 40 CFR 60.8, and 40 CFR Subpart KKKK]

15. Restricted Operation: The permittee shall not exceed the following parameters following shutdown of Units 1, 2 and 3:
    a. The hours of operation of the CTs are not limited (8,760 hours per year).
    b. Distillate oil firing is limited to 1,000 hours per CT (i.e. 5,000 hours total aggregate for all five CTs) during any consecutive 12-month period.
    c. Operation of the DBs is limited to 2,434 hours per DB (i.e. 9,736 hours aggregate for four DBs) during any consecutive 12-month period.
    d. Power (steam) augmentation shall be limited to 1,688 hours per CT during any consecutive 12-month period.
    e. Other than startup, shutdown, fuel switching or documented malfunction the CTs shall operate above 70% load during simple cycle operation.
16. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTs may operate under the following methods of operation after shutdown of Units 1, 2 and 3
    a. *Simple Cycle (SC) Operation:* All five CTs may operate in simple cycle (SC) mode whereby the turbine exhaust gas (TEG) exits through or is diverted to a stack unassociated with a DB-fired HRSG. This method of operation will be an infrequent occurrence for the four CTs that will typically operate in combined cycle mode as described below.
    b. *Combined Cycle (CC) Operation*: The four CTs associated with combined cycle Unit 4 may operate in combined cycle (CC) mode whereby the TEG is exhausted to their respective duct-fired HRSGs for energy recovery in order to raise steam to drive the single steam turbine-electrical generator (STG) subject to the restrictions of this permit.
    c. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling systems may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.
    d. *Duct Firing*: The DB within each HRSG may be fired with natural gas to reheat the TEG in order to provide additional steam to the STG or the CTs for power augmentation.
    e. *Power augmentation:* Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the CT compressor discharge, thus increasing the power produced by the expander portion of the turbine.

    [Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

17. New Source Performance Standards for NO_X: Emissions of NO_X shall not exceed the following emission limits for each CT or CT/DB-fired HRSG determined pursuant to 40 CFR 60, Subpart KKKK.

Pollutant	Fuel	Method of Operation [a]	CEMS [b] Rolling Average ppmvd @ 15% O_2
NO_X [c]	Oil	CT (SC)	42 on 4-hour basis
		CT (CC)	42 on 30-operating days basis
	Gas	CT (SC)	15 on 4-hour basis
		CT (CC)	15 on 30-operating days basis
		CT & DB	

a. CT (SC) means operation of CT in simple cycle mode. CT(CC) means operation of CT in combined cycle without use of the DB. CT & DB means operation in combined cycle mode and using the DB.

b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks.

c. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS.

Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

18. Best Available Control Technology (BACT) Emissions Standards for CO and VOC: Emissions of VOC and CO shall not exceed the following emission limits for each CT or CT/DB-fired HRSG.

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

b. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

[Rule 62-210.200(Definitions – BACT) and 62-212.400 F.A.C.]

19. New Source Performance Standard for SO_2: Pursuant to §60.4330(a)(2), SO_2 emissions are limited in NSPS Subpart KKKK by a prohibition on the firing of any fuels that contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

20. Measures to Limit Particulate Emissions (PM/PM_{10}/Fine Particulate Matter): The following measures and limitations, in conjunction with decreases from other units, effectively limit combined annual PM/PM_{10} emissions to a level that ensures net emissions increases are well below the significant emission rate at which PSD applies and a subsequent BACT determination is required. These measures also minimize fine particulate emissions and formation:

    a. *Fuel Sulfur Limits*: The sulfur concentration shall be limited to 2 grains per 100 standard cubic feet of natural gas. The sulfur concentration in the distillate fuel oil used shall be limited to 0.05 percent. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content.

    b. *Visible Emissions*: Visible emissions shall not exceed 10 percent opacity for each 6-minute block average. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

    c. *Ammonia Emissions (Slip) Limits*: Ammonia emissions shall be limited to 5 ppmvd @15% O_2. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

    [62-212.400(12)(PSD Avoidance)]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 18 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS or Acid Rain programs.}

21. 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 CTs, HRSGs, 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.]

22. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

23. Definitions

    a. *Startup* is defined as 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. [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
    [Rule 62-210.200(230), F.A.C.]

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

24. 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 preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

25. Allowable Data Exclusions: As per the procedures in this condition, limited amounts of CO CEMS emissions data may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C. For each CT/HRSG system, excess emissions resulting from startup, shutdown, and documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, up to 8 hours of excess emissions from any CT/HRSG system may be excluded in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, each CT/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

    b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, up to 3 hours in any 24-hour period of excess emissions from any CT/HRSG system can be excluded.

    c. *CT/HRSG System Cold Startup*: For cold startup of a CT/HRSG system, up to 4 hours in any 24-hour period can be excluded. "Cold startup of a CT/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

    d. *Simple Cycle CT Startup*: For startup of a CT for the purpose of operation in simple cycle mode, up to 1 hour in any 24-hour period of excess emissions can be excluded.

    e. *Fuel Switching*: For fuel switching, up to 2 hours in any 24-hour period can be excluded.

26. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 7 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

27. Test Methods: Any 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.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
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

No other methods may be used unless prior written approval is received from the Department.
[Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

28. Initial Compliance Determinations: Each CT shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Reference method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X compliance tests. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

29. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour and 12-month CO emission standards, and the NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

30. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CT shall be tested to demonstrate compliance with the emission standards for visible emissions. CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall

indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing for the reasons such as exceedance of the CO limit or those given in Appendix SC, Special Compliance Tests.}

[Rules 62-212.400, 62-210.200 (243) (BACT), 62-4.070 (3) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

31. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO from the HRSG stacks and NO_X from all stacks in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
    a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. 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 semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
    b. *NO_X Monitors.* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.
    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

32. CEM Data Requirements:
    - *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS 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 CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions.

- *Valid Hour*: Hourly average values shall begin at the top of each hour. 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). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.
- *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and 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 all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]
- *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CO CEMS compliance demonstration subject to the provisions of Condition Nos. 25 and 26 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the 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 such episodes. 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.
- *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report 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.

[Rules 62-4.070(3) and 62-212.400(12), F.A.C.; 40 CFR 75]

33. <u>Ammonia Monitoring Requirements:</u> In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update 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 and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the CT load condition. [Rules 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

34. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CT and HRSG duct burner system 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.]

35. Monthly Operations Summary : By the 10^{th} calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. 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. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3), 62-212.400, 62-210.200 (38) and 62-210.200 (243)(BACT), F.A.C.]

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

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81. More recent versions of these methods or other Department approved methods may be used.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

37. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

38. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports*: Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions of the applicable NSPS that occurred during the previous semi-annual period.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 and Subpart KKKK]

39. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. Auxiliary Boiler and Process Heaters (EU-014 and 015)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
014	One Large Gaseous-fueled Auxiliary Boiler (99 MMBTU/hr and 85,000 lb/hr)
015	Five Small Gaseous-fueled Process Heaters (3 MMBtu/hr)

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

   [Rule 62-212.400, F.A.C.]

2. NESHAP Subpart DDDDD Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 63, Subpart DDDDD, which applies to an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 40 CFR 63.2.

   [40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater]

3. NSPS Subpart Dc Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]

EQUIPMENT, CAPACITIES AND LIMITATIONS ON OPERATION

4. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply to the CTs. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of the limited use gas-fueled auxiliary boiler shall not exceed 1,000 hours per year. The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C. and 40 CFR 63.7575]

EMISSIONS, FUELS AND TESTING REQUIREMENTS

6. Auxiliary Boiler Emissions Limits:

CO (BACT, Subpart DDDDD)	VOC (BACT)
0.08 lb/MMBtu, 400 ppmvd @3% O_2	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.; 40 CFR 60, Subpart Dc; 40 CFR 63, Subpart DDDDD]

7. Auxiliary Boiler Testing Requirements: This unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 63.7]

8. Auxiliary Boiler Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

9. Annual CO Performance Test for Auxiliary Boilers: Pursuant to 40 CFR 63.7515(e) permittee shall conduct an annual CO test according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

   [40 CFR 63.7515 and Rule 62-204.800(11)(b)84. F.A.C.]

10. Natural Gas Fired Process Heaters Emissions Limits:

CO (BACT)	VOC (BACT)
0.08 lb/MMBtu	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.]

11. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

12. Natural Gas Fired Process Heaters Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

13. Notification: Initial notification is required for the limited use 99 MMBtu/hr gas-fueled auxiliary boiler. Initial notification is not required for the five small gas-fueled 3 MMBtu/hr process heaters. [40 CFR 63.9, 40 CFR 63.7506(c) and Rule 62-204.800(11)(b) F.A.C.]

14. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters and auxiliary boilers. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

C. Distillate Fuel Oil Storage Tanks (EU-016)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
016	Two Nominal 3.5 million gallon distillate fuel oil storage tanks

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for volatile organic compounds (VOC) for these emissions units.

NSPS APPLICABILITY

2. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain two 3.5 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to the gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

4. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

5. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

6. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective Material Safety Data Sheets (MSDS) for the low sulfur fuel oil stored in the tanks. [Rule 62-4.070(3) and 62-212.400, F.A.C.]

D. Emergency Diesel Fire Pump (EU-017)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
017	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank.

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

2. NSPS Subpart IIII Applicability: This fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and is subject to 40 CFR 60, Subpart IIII. It shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines].

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) and an associated 500 gallon fuel oil storage tank.

4. Hours of Operation: The fire pump may operate in response to emergency conditions and 40 non-emergency hours per year for maintenance testing.
   [Applicant Request; Rule 62-210.200 (PTE), F.A.C.

EMISSIONS, FUELS AND TESTING REQUIREMENTS

5. Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

   Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

6. Fire Pump Engine Emissions Limits:

   The following limits apply based on the size category of the fire pump located at the facility.

Size (hp)	CO (BACT, IIII)	NMHC*+NO_X (BACT for VOC, IIII)	PM
175 and greater	2.6 gm/bhp-hr	7.8 gm/bhp-hr	0.40

   Note 1. Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

7. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power Corporation dba
Progress Energy Florida
P.L. Bartow Power Plant

1,475 Megawatt Power Plant Repowering Project
New Gas-fueled Combined Cycle Unit and Simple Cycle Unit
Shutdown of three Residual Oil-fueled Units

Pinellas County

DEP File No. 1030011-010-AC (PSD-FL-381)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section

December 13, 2006

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power Corporation dba
Progress Energy Florida
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Rufus Jackson

Processing Schedule

- July 31, 2006: Received PSD application
- August 30: Department's Request for Additional Information (RAI)
- October 3: Received Response to RAI
- October 26: Received Additional Information
- December 13: Intent to Issue, Draft PSD Permit, and Technical Evaluation Distributed

Facility Description and Location

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF) proposes to construct a natural gas-fueled combined cycle unit and a simple cycle unit and to shut down the three residual oil-fueled units at the P.L. Bartow Power Plant on Weedon Island on the eastside of St. Petersburg, Pinellas County. The location with respect to other PEF facilities in Florida is shown in Figure 1. Also shown is the location of Weedon Island within Tampa Bay.

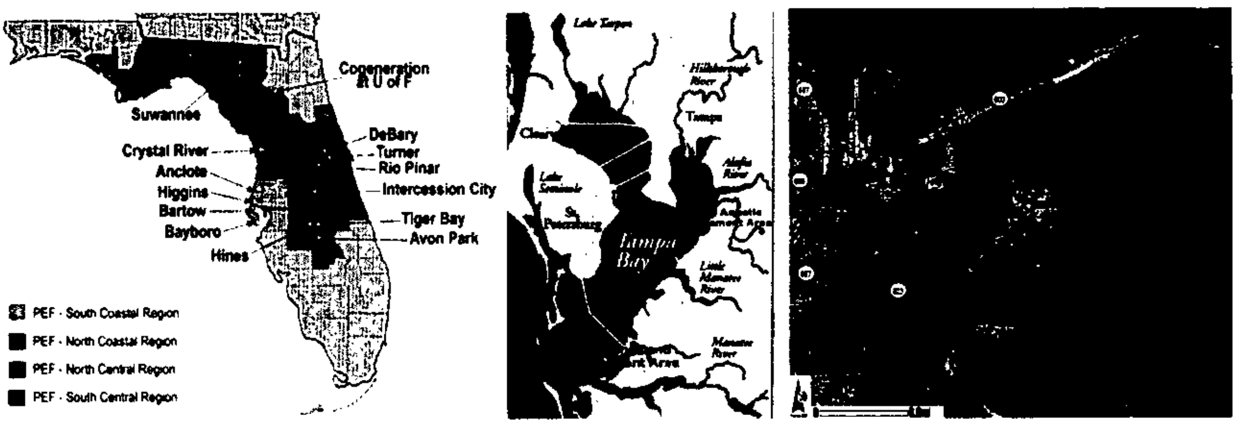

Figure 1. Bartow Power Plant in PEF System and Location of Weedon Island and Plant.

The plant is located approximately 83 km south of the PSD Class I Chassahowitzka Wilderness Area. The facility UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

Standard Industrial Classification Codes (SIC)

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

Regulatory Categories

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources: The proposed project is subject to 40CFR60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also covers duct burners that are incorporated into combined cycle projects. Stationary combustion turbines subject to KKKK are exempt from 40 CFR 60, Subpart GG. Heat recovery steam generators and duct burners subject to KKKK are no longer subject to 40 CFR 60, Subparts Da, Db and Dc for duct burners.

Title I, Section 112, Clean Air Act, Hazardous Air Pollutants (HAP): The existing facility is a major source of HAPs. Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines applies to any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions. Because the CTs for this project will have the potential for an aggregate oil-firing total of 5,000 hours (>> 1,000 hours applicability threshold) during any calendar year, Subpart YYYY is applicable.

Title I, Part C, Clean Air Act, Prevention of Significant Deterioration (PSD): The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C.

Title IV, Clean Air Act, Acid Rain Provisions: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits: The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAP. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Clean Air Interstate Rule (CAIR): The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting): The facility was not certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is not subject to Siting because there will be no net increase in steam-generated electrical power. [Design; Letter from Applicant to Siting Office dated December 19, 2005]

2. PROPOSED PROJECT

Project Description

The project is the construction of a gas-fueled combined cycle unit with a nominal rating of 1,280 megawatts (MW) at ISO conditions and a gas-fueled simple cycle unit combustion turbine-electrical generator with a nominal rating of 195 MW at ISO conditions.

The combined cycle unit will consist of: four Siemens SGT6-5000F combustion turbine-electrical generators (CTG) with a nominal rating of 215 MW at ISO conditions when practicing power (steam) augmentation; four supplementary-fired heat recovery steam generators (HRSG's) each equipped with a nominal higher heating value (HHV) 500 million Btu per hour (mmBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG).

Each CTG within the combined cycle unit will also be capable of operating in simple cycle by directing the exhaust to a bypass stack instead of to the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

The simple cycle CTG will exhaust through its own 120 foot stack. All CTGs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures. Each CTG will be capable of firing backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). Two 3.5 million gallon distillate fuel oil storage tanks are included.

A single auxiliary boiler with a nominal capacity of 85,000 pounds per hour (lb/hr) of steam and a heat input rating less than 100 mmBtu/hr will be included for the initial combined cycle unit startup and occasionally thereafter when steam is not available during a startup.

Five gas-fired fuel heaters each with nominal heat input ratings of 3 mmBtu/hr will be provided to maintain natural gas fuel for the CTGs at temperatures above the dew point. A nominal 300 hp diesel-fueled emergency fire pump is also included. Following is a listing of the new emissions units for the proposed project.

ID	Emissions Unit Description
009	Unit 4A – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
010	Unit 4B – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
011	Unit 4C – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
012	Unit 4D – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
013	Unit 5 – one 195 MW (ISO) gas turbine operating in simple cycle mode
014	One nominal 85,000 lb/hr (99 mmBtu/hr) auxiliary boiler
015	Five nominal 3 mmBtu/hr gas-fired process heaters
016	Two nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
017	One nominal 300 horsepower diesel-fueled emergency fire pump

* ISO indicates nominal rating at sea level, 59 degrees F and 60% relative humidity. The ratings shown for the CTGs associated with the combined cycle unit reflect gas firing and power (steam) augmentation.

Following are additional project characteristics.

- Primary Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and low sulfur distillate oil. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing.
- Add-on Controls: Selective catalytic reduction (SCR) systems will be installed on the CTGs used in the combined cycle unit to further reduce NO_X emissions during combined cycle operation. The extent of reduction below the permitted emission limit will depend on the company's NO_X strategy to comply with the Clean Air Interstate Rule (CAIR).

- Continuous Monitors: Each CTG stack equipped with continuous emission monitoring systems (CEMS) as required to monitor NO_X emissions in accordance with the acid rain provisions. Each HRSG stack will have a NO_X CEMS and a CO CEMS that will be employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

The following figure includes a photograph from the Progress Energy website of the three existing residual oil-fueled units taken in a south/southwesterly direction. The other graphic is an artist rendition of the combined cycle unit in an east/northeasterly direction. The eight stacks associated with the combined cycle are clearly shown. Also shown are the stacks of the three existing units destined for shutdown.

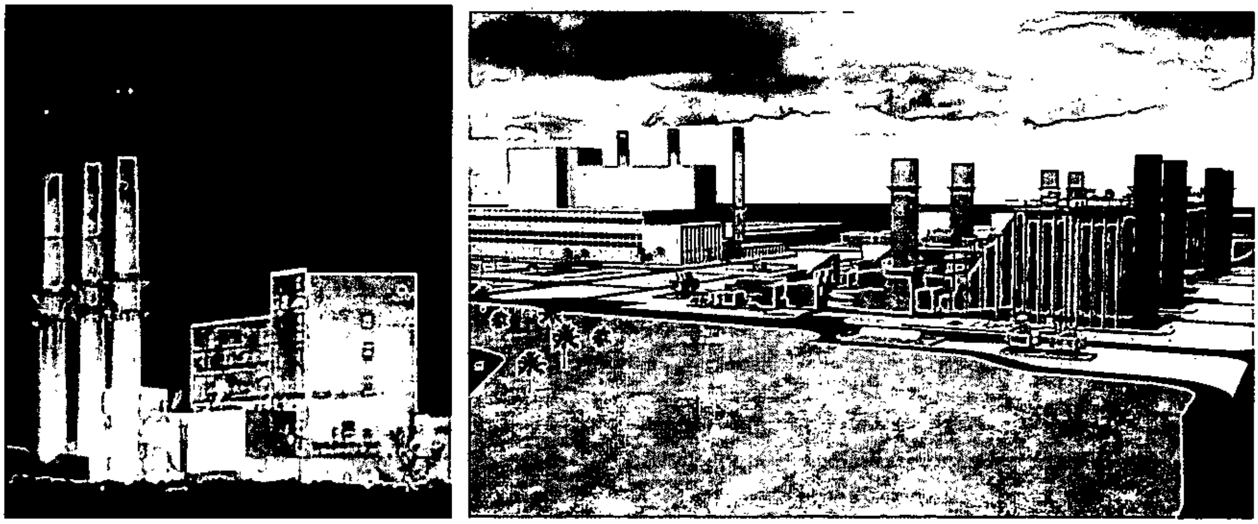

Figure 2. P.L. Bartow Units 1, 2 and 3. Artist's Rendition of New Combined Cycle Unit

The shut down of the three units will be quite noticeable as they are presently fueled by 2.5% sulfur residual fuel oil. Also the existing units are subject to a 40% visible emissions standard and are allowed even greater opacity during soot blowing. By contrast, the new unit will use inherently clean fuels and will typically exhibit no visible emissions.

The project will also require, via separate permits, the upgrading about four miles of underground transmission lines and the construction of a 17-mile long underwater natural gas pipeline by Gulf Stream Natural Gas L.L.C.

PEF requests that two of the new CTGs be available for simple cycle service for a period of seven months prior to shut down of Units 1, 2 and 3. The other two CTGs associated with the combined cycle unit will be placed in service as part of the combined cycle unit is in service after Units 1, 2 and 3 shut down. The ramifications of the early startup of two CTGs in simple cycle are discussed below.

Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A longitudinal section diagram of a Siemens SGT6-5000F (compressor, combustor section and rotor inside of casing) is shown in the left hand side of the figures below. The photograph (Siemens 2005 PowerGen presentation) on the right hand side of the figure is of the compressor and rotor section within the bottom half shell. The compressor rotating blades are on the left hand side of each graphic and the 4-stage expansion section is towards the right.

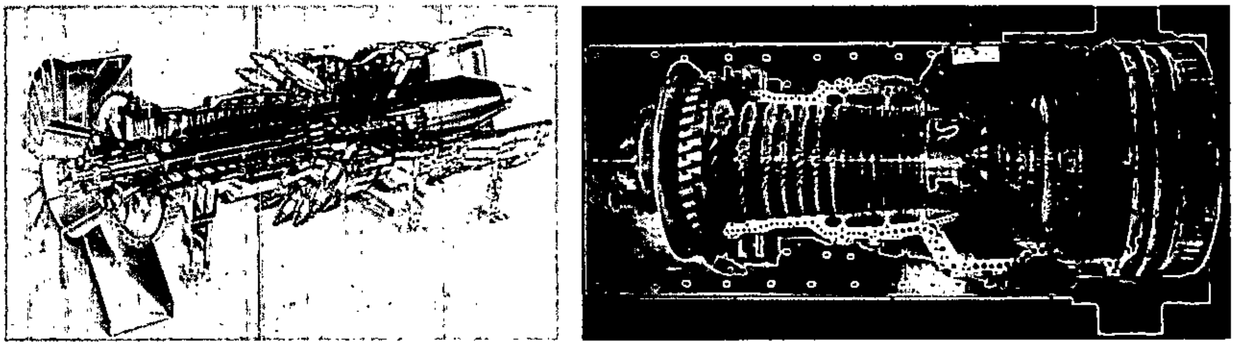

Figure 3. SGT6-5000F. Internal View and Overhead View of Compressor and Rotor.

Ambient air is drawn into the 16-stage compressor of the 5000F where it is compressed to a pressure ratio of approximately 17 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate air-cooled, can-annular, Dry Low NO_X (DLN) combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is on the order of 2,500 °F.

The hot combustion gases routed through the air-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. 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. Turbine exhaust gas (TEG) is discharged at a temperature of approximately 1100 °F and high excess oxygen. The TEG is available for additional energy recovery.

A basic combined cycle unit with only one CTG, unfired HRSG and a steam turbine-electrical generator (STG) is depicted in Figure 4. The heat from the reheated TEG is used to raise steam in the HRSG. The steam from the HRSG, in-turn, drives the STG producing additional electrical power.

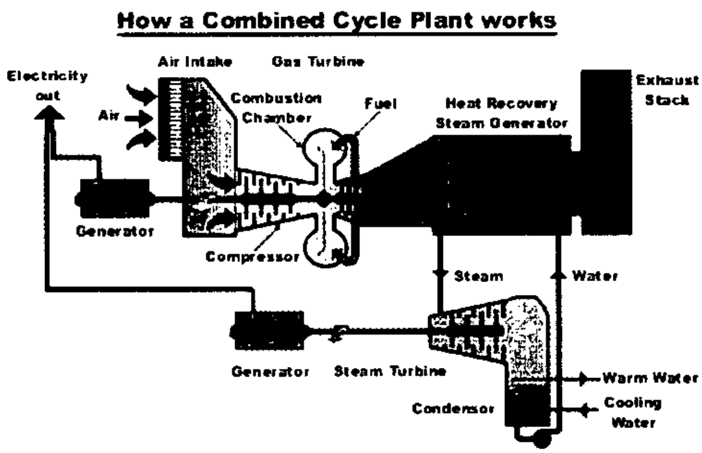

Figure 4. Combined Cycle Unit (Unfired HRSG)

The proposed project will have four CTGs and four HRSGs that will drive a single STG. The TEG will be reheated by natural gas fired in the duct burners located within each HRSG. Some of the steam will be returned to the CTGs to produce extra power by steam augmentation.

In simple cycle mode, the thermal efficiency of the Siemens SGT6-5000F is approximately 37 percent (%) on the basis of lower heating value (LHV) and 34% on the basis of higher heating value (HHV). In combined cycle mode, the thermal efficiencies are approximately 57% and 52% based on LHV and HHV respectively.

Additional features of the combined cycle unit include:

- Inlet Conditioning: Evaporative cooling is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. This is typically implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2,434 hours of duct burning per year for each HRSG.
- Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine. PA causes greater uncontrolled CO emissions. The applicant requests 1,688 hours of PA for each CTG.
- Simple Cycle (SC) Mode: Bypass stacks have been included in the design allowing the CTGs associated with the combined cycle unit to operate in SC mode. This is a low probability scenario given the lower thermal efficiency. However it allows operation if there are STG, HRSG, or main condenser problems that would preclude operation in combined cycle mode.

Further process details are provided in the Draft BACT determination, Section 4.0 below.

3. RULE APPLICABILITY

Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	**Description**
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain – Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions
Part 96	NO_X Budget Trading Program for State Implementation Plans

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as described in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant.

The PEF P.L. Bartow Power Plant is a Major Stationary Source with respect to the PSD Rules because it is a fossil fuel-fired steam electric plant of more than 250 million Btu heat input and has the potential to emit 100 tons per year or more of a PSD pollutant.
(Rule 62-210.200(185)(a)1., F.A.C.)

The Repowering Project is a Major Modification of a Major Stationary Source if there will be a net emissions increase greater than the significant emission rate (SER) of a PSD pollutant. The SER means a rate of pollutant emissions that would equal or exceed: 100 tons per year (TPY) of carbon monoxide; 40 TPY of nitrogen oxides (NO_X), sulfur dioxide (SO_2), or volatile organic compounds (VOC); 25 TPY of particulate matter (PM); 15 TPY of PM smaller than 10 microns (PM_{10}); 7 TPY of sulfuric acid mist (SAM); or 0.6 TPY of lead (Pb). [Rule 62-210.200(185)(a)1., F.A.C.]

For each pollutant with a net emission increase exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) as defined in Paragraph 62-210.200(39), F.A.C. to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for CO and VOC only for reasons described below.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. [Rule 62-212.400(5) through (9), F.A.C.]

Estimates of Net Emissions Increases

The new combined cycle unit and new simple cycle unit will result in emissions of CO, NO_X, SO_2, PM/PM_{10}, SAM and VOC. The shut down of the three residual oil-fueled units will result in reductions of the same pollutants.

The following table is a summary of the emissions increases and decreases resulting from the proposed project to determine which pollutants will be emitted in excess of their respective SERs.

Table 1. Applicant's Summary of Net Emissions Increases and PSD Applicability for the P.L. Bartow Plant Repowering Project Permanent Scenario.

Pollutant	Baseline Emissions TPY	New Units Potential Emissions TPY	Net Emissions Increases (Decreases) TPY	PSD SER TPY	PSD?
SO_2	24,816	466	(24,350)	40	No
PM/PM_{10}	804/559	413/413	(391)/(146)	25/15	No
NO_X	4,043	3,191	(852)	40	No
CO	367	938	571	100	Yes
VOC	57	145	88	40	Yes
SAM	423	72	(351)	7	No
Lead	0.10	0.06	(0.04)	0.6	No
HAPs	No Estimate	23.1	< 23.1	NA	No

The baseline emissions are for Units 1, 2 and 3 that are destined for shut down. SO_2 and NO_X emissions were calculated using the continuous emissions monitoring systems (CEMS) required by the Acid Rain Program. These two pollutants account for 95% of the present PSD pollutant emissions. The rest of the emissions were calculated by annual emissions tests or by emission factors.

There will be decreases in all PSD pollutants except for CO and VOC. Given the high opacity limits at the existing units, the quality of fuel used and the frequency of soot blowing, the Department believes that baseline annual PM/PM_{10} emissions are greater than estimated and that reductions will be greater than estimated. The applicant's estimates of baseline PM/PM_{10} and CO are likely conservative and tend to make it more likely that PSD will apply than otherwise.

Although no baseline estimates of HAPs are provided, the switch from residual fuel oil to inherently clean fuels will reduce emissions of nickel (Ni, a HAP) and vanadium (V, not classified as a HAP) that tend to catalyze the oxidation of SO_2 to SAM.

According to the applicant's estimates, net emissions increases of CO and VOC will be greater than their respective SERs. Therefore, a PSD review and determinations of BACT are required for those pollutants.

The applicant has requested authorization to use two of the CTGs for a seven month period prior to the permanent shut down of Units 1, 2 and 3. During the period December 2008 through June 2009, those CTGs will be operated as simple cycle peaking units (intermittent duty with rapid startup to full load operation) prior to their incorporation into the combined cycle unit.

Because this initial phase will occur prior to the shut down of Units 1, 2 and 3 it is not possible to take "credit" for contemporaneous emissions reductions when calculating net emissions increases. Rather than making permanent and enforceable emissions reductions from Units 1, 2 and 3 the applicant will insure that emissions from the initial simple cycle phase will not exceed the respective significant emission rate (SER) for any PSD pollutant.

The following table is a summary of the emissions increases resulting from the operation of two CTGs in simple cycle mode.

Table 2. Applicant's Summary of Net Emissions Increases and PSD Applicability for the Operation of two CTGs in Simple Cycle Mode for Seven Months.

Pollutant	Emissions from Two Simple Cycle CTGs tons	PSD SER TPY	PSD?
SO_2	<< 39	40	No
PM/PM_{10}	< 24/14	25/15	No
NO_X	39	40	No
CO	< 99	100	No
VOC	<< 39	40	No
SAM	<< 6	7	No
Lead	<< 0.6	0.6	No

According to the equipment characteristics NO_X is the controlling pollutant with respect to PSD applicability. Over three times as much NO_X will be emitted compared with CO. During this temporary period of simple cycle peaking, the Department will limit NO_X emissions to 39 tons from both units (combined) with compliance demonstrated by CEMS. In addition, the total aggregate hours of operation will be limited to 1,100 hours during this period. By doing so, the Department will have reasonable assurance that emissions of all pollutants will be less than their respective SERs. The units will still be subject to the unit specific requirements of this permit and 40 CFR 60, Subpart KKKK-Standards of Performance for Stationary Combustion Turbines.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Paragraph 62-210.200 (39), FAC as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and*

available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

According to Rule 62-212.400(4)(c), F.A.C., the applicant must at a minimum provide certain information in the application including:

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

According to Rule 62-212.400(10), F.A.C., the Department is required to conduct a control technology review and shall not issue any permit unless it determines that:

(a) The owner or operator of a major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.

(b) The owner or operator of a new major stationary source shall apply best available control technology for each PSD pollutant that the source would have the potential to emit in significant amounts.

(c) The owner or operator of a major modification shall apply best available control technology for each PSD pollutant which would result in a significant net emissions increase at the source. (This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.)

(d) The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C.

4.2 NO_X Emission Technology and Limits (non-BACT)

Although a BACT determination is not required for NO_X, it is nevertheless useful to discuss the technology to be employed for NO_X in order to gain a better understanding of the possibilities and limitations to CO and VOC control. Additionally, it is necessary to insure that the project will comply with the NO_X requirements given in 40 CFR 60, Subpart KKKK.

NO_X Formation

NO_X forms 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. It also forms by oxidation of nitrogen present in the fuel.

Thermal NO_X. Thermal NO_X forms in the high temperature area of the gas turbine combustor as seen on the left hand side of Figure 5. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 5, which is from a GE discussion on these principles.

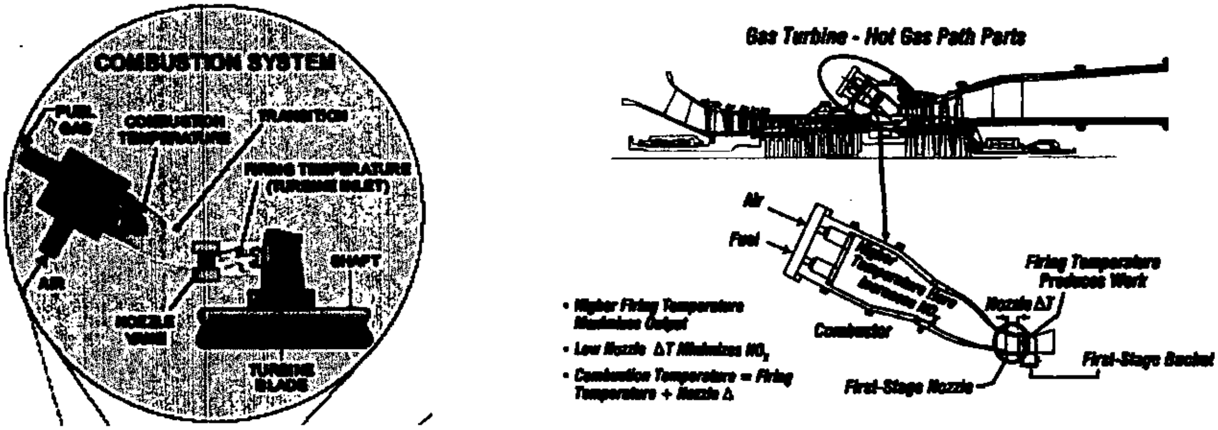

Figure 5. Relation between Combustion and Firing Temperatures and NO_X Formation

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.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the PEF project.

Descriptions of Available NO_X Controls

Wet Injection. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below.

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 traditional DLN combustor for the Siemens/Westinghouse 501FC engine (the predecessor of the SGT6-5000F) was a partially premixed combustor, with a center-core pilot diffusion flame surrounded by eight lean premix nozzles where the fuel is injected at multiple ports inside the combustor and mixes with the combustion air in advance of the flame zone.

Figure 6 shows the combustor with the air bypass configuration (eliminated from some recent models).[1]

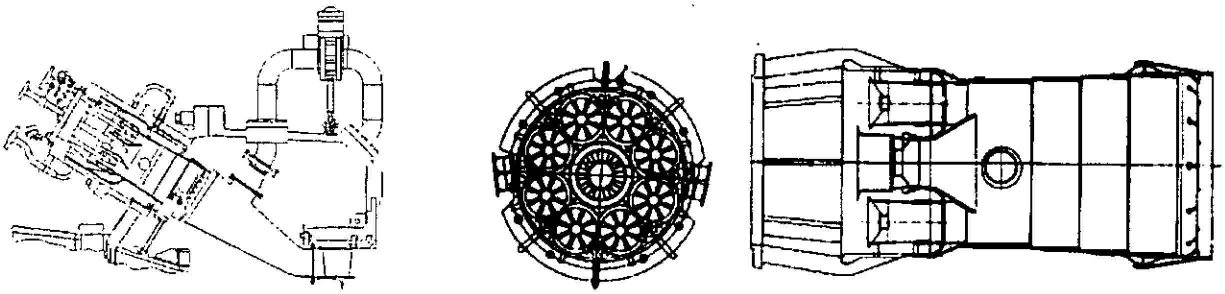

Figure 6. Siemens/Westinghouse 501FC DLN System and Combustion Basket.

In the combustor, natural gas is injected into three or four stages; pilot, A, B, and C (for certain configurations). The diffusion flame pilot injector provides stability for the premixed A, B, and C-stages. Because a diffusion flame has high NO_X emissions it is necessary to minimize the amount of flow through the pilot.

The majority of the fuel is injected upstream of the pilot through the main A and B stages. The main fuel is injected tangential to the flow direction through 8 fuel rockets each with 4 fuel injection holes. This fuel premixes with the air before reaching the combustion zone. During the C-stage, a small amount of fuel is injected in a zone called the "top hat" region before the flow enters the basket.

The C-stage provides additional premixing of the fuel and air and allows a reduction in the pilot fuel flow. Typically the DLN combustor is ignited on the pilot and A-stage. The B-stage is initiated at 30% load and the C-stage is initiated at 50% load.

According to Siemens, a DLN combustion system improvement reduced NO_X from >25 parts per million by volume (ppmv) down to <9 ppmv and was successfully demonstrated on a service unit in 2004.[2] The exact profile with respect to load for that installation is not known. Presumably values significantly greater than 9 ppmvd occur during the pilot, A-Stage, B-Stage and early C-Stage operational loads.

The exact features of the DLN (or possibly Ultralow NO_X - ULN) technology that will be incorporated into the proposed project are not yet known to the Department. However, the applicant has proposed to meet NO_X limits of 15 ppmvd for natural gas firing to meet the requirements of 40 CFR 60, Subpart KKKK for combined cycle units. It appears that this value can be accomplished with the described DLN technology.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water.

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

Figure 7 below is a diagram of the typical Nooter Eriksen (NE). NE supplied the HRSGs for the PEF Hines Energy Complex Power Block 1 also shown in the figure.

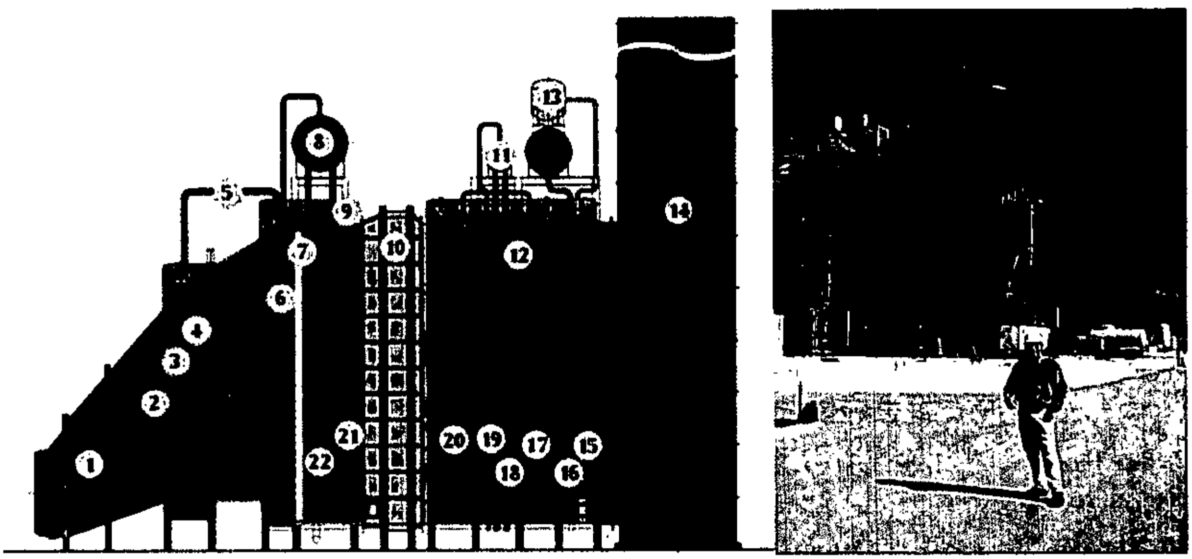

Figure 7. Key Nooter Eriksen HRSG Components (10 is SCR) and PEF Hines Block 1

Components 10 and 21 represent the SCR reactor and the ammonia injection grid. In this arrangement the SCR system lies between the high pressure evaporator (22) and the high-pressure economizer (20) where the temperature requirements for conventional SCR can be met.

The external lines to the ammonia injection grid are easily visible in the photograph. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. The SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

In the given design, the duct burner (4) lies between a "split" high pressure superheater (3 and 6). For future reference in discussion below, the CO catalyst in this design is Component 7.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions. SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order of 95 to 99%.

Although the combined cycle unit can likely comply with the requirements of Subpart KKKK, PEF will install an SCR system within each of the four HRSGs. When used, this will further insure compliance and will also provide flexibility in achieving PEF's overall company strategy pursuant to the Clean Air Interstate Rule (CAIR).

4.3 CO and VOC BACT Determination

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst.

The following table contains proposed CO and VOC emission estimates provided in the application for the SGT6-5000F CTGs that will be used for the project.

Table 3. Applicant's CO and VOC Estimates for SGT6-5000F CGTs (ppmvd @15% O_2)

Load Range	Fuel/Mode	CO	VOC
70-100%	Gas	4	1
60-70%	Gas	10	4
100%	Gas/Duct Burner	9	2
70-100%CO	Fuel Oil	30	10

The projections while firing natural gas in the range of 70-100% of full load are consistent with the full load experience of the predecessor Siemens-Westinghouse 501F (SW 501F) CGTs installed at the PEF Hines Energy Complex. Hines CGTs 1A and 1B exhibited full load CO and VOC emissions during all compliance runs of less than 1.0 and less than 0.6 ppmvd for the two pollutants respectively.[3] CO and VOC emissions should be very low based on the high combustion temperature and the relatively high temperature and excess air in the turbine exhaust gas (TEG).

However, there is concern regarding the performance on natural gas at loads less than 70%. Based on the values in the above table, performance is projected to degrade somewhat by 60 to 70% load. Additionally, it is known that the applicant wants the ability to turn down the load to levels less than shown in the table. Therefore, it is important to have an understanding of performance at low load because of CTG startups and shut downs that may or may not involve HRSG or STG startups and shut downs. Fuel oil and duct burner performance are discussed further below.

The Department requested manufacturer's curves showing expected emissions with respect to CGT load as percent of full load.[4] In its response, the applicant advised that according to Siemens "they do not provide 'curves' for various loads".[5] In response to a request related to a separate project, PEF provided tabulated CO data covering startups, shut downs, fuel switches, tunings and malfunctions.[6] The data comprise experience from four SW501F CGTs that are (at least to the untrained eye) identical to the SGT6-5000F.

The Department entered the data into a spreadsheet and produced the following charts relating CO emissions to the described events.

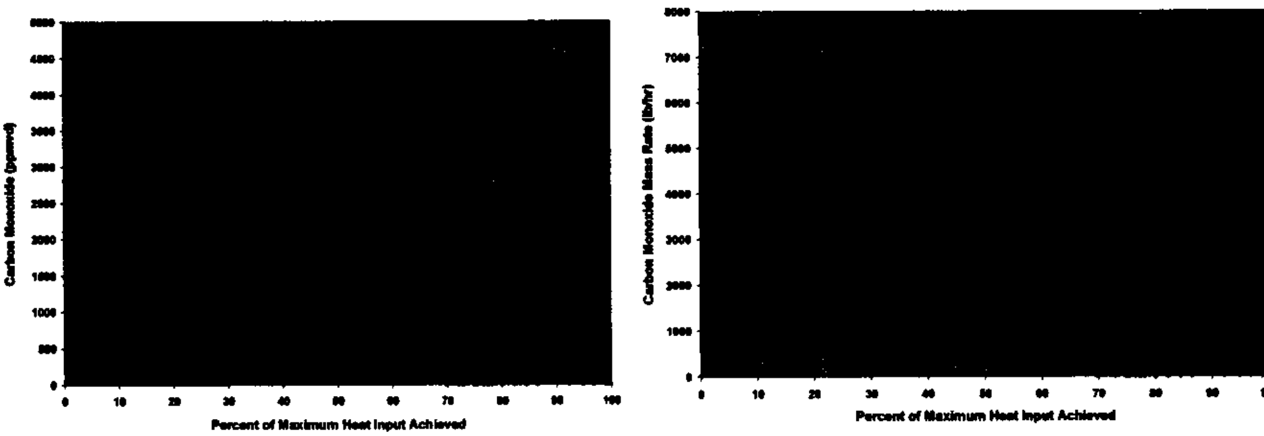

Figure 8. CO Emissions during Certain Low Load and Transient Conditions

The data indicate that CO emissions are very high at least during the transient periods related to the mentioned events. During a number of hours more than 2 tons of CO were emitted at concentrations of 8,000 ppmvd at roughly 50% of full load when the C-Stage is initiated.

The Department also focused on operation greater than 50% of full load to assess the likely performance of the units given that the data are indeed representative of such operation unassociated with transients. The results are shown in the graph on the following page. Again the data suggest the possibility of high CO emissions.

Siemens is at least aware of these issues. The Department obtained a recent paper presented by Siemens at the 2005 PowerGen Conference. In it Siemens described some possible improvements allowing faster startup times and also the manner by which they can achieve low CO emissions at partial loads on the SGT6-5000F CTG.[7] According to Siemens (with some minor paraphrasing):

"The original startup time from initiation to full power took approximately 30 minutes. The improved start time capability is as follows: 5 minutes from start initiation to minimum load, and then the GT is loaded at 30 MW/minute. This permits 150 MW within 10 minutes.

To achieve the improved start capability the following steps were taken:

1. *Implement static frequency converter (static start), whereby the CTG generator operates as a motor replaces the mechanical starter motor. This allows more efficient and faster rotor acceleration than the equivalently sized mechanical starting motor.*

2. *The turning gear (TG) speed was increased from 3 rpm to 120 rpm. The higher TG speed enables the generator rotor wedges to lock up and also helps the engine cool down faster, because the turbine parts are cooled faster and tip clearances are similar to the cold tip clearance."*

"Reduced low load CO emissions were achieved by operational modifications which include a second modulating circuit added to turbine cooling air supply. When load is reduced, the second modulating circuit is opened bypassing additional cooling air around the combustor. Bypassing air around the combustor increases combustor flame temperature and hence limits CO production. There are other measures which can be taken to reduce CO if necessary, including changes to valve scheduling to allow compressor air to be bypassed into the exhaust. With this equipment & operational changes, CO is kept to <10 ppm down to between 45% and 50% load. This CO reduction will reduce total CO mass emissions by 70% per startup-shutdown cycle."

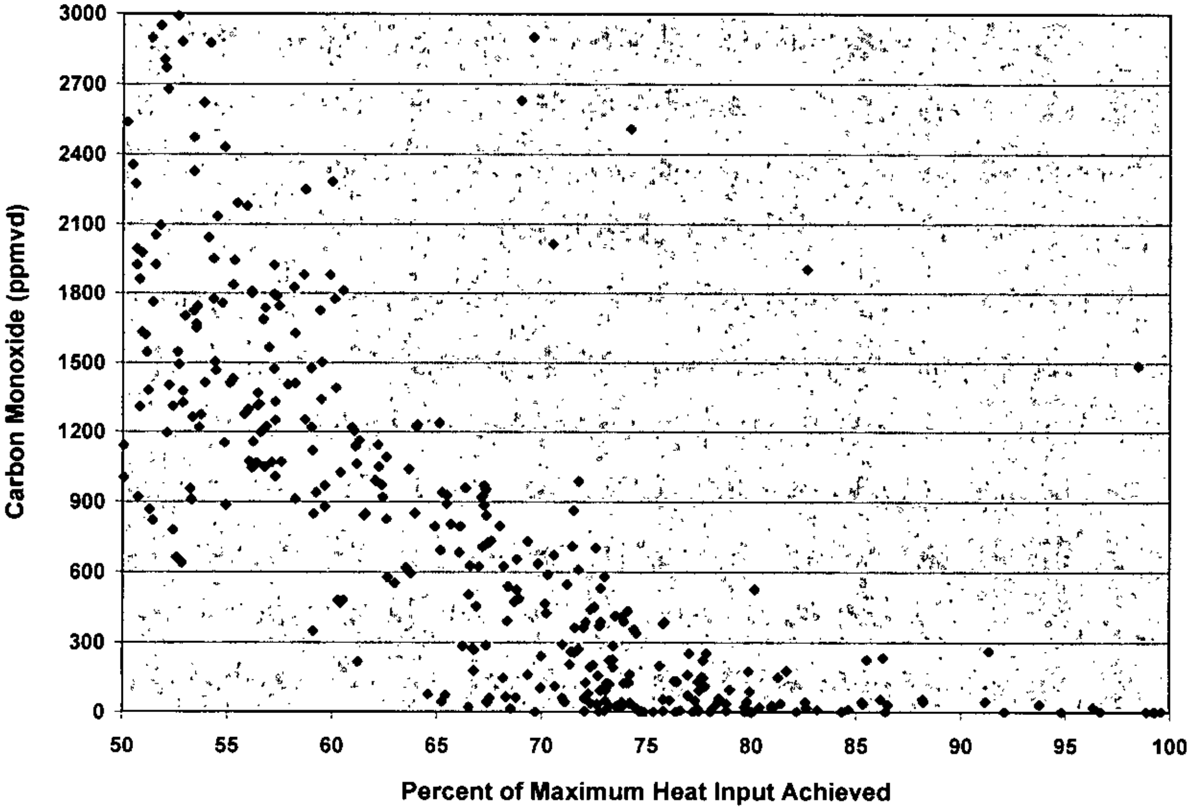

Figure 9. CO Emissions during Certain Medium Load Conditions

The following figures from the Siemens presentation compare original to improved startup characteristics. The graph on the left demonstrates the reduction of startup times which may be minimized to reduce CO emissions during these periods. The graph on the right suggests that the operating cycle can be improved to extend the "low CO" range to loads less than 50%.

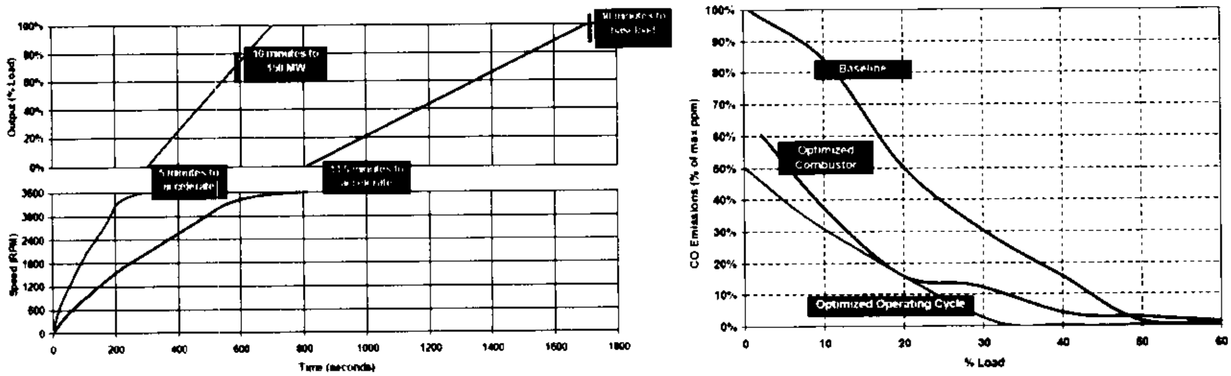

Figure 10. Improved Startup Times to High Load. Relative CO Emissions at Low Load.

The Department does not dispute that the emissions can be reduced to less than 10 ppmvd in the 45-50% load range as suggested by the Siemens paper. However, the applicant has not provided information regarding the measures to actually be incorporated to avoid very high CO emissions during startups, shutdowns and low load (whether or not the low load is associated with startups and shutdowns).

The options described by Siemens may be available for the project to help achieve BACT level CO and VOC emission limits and possibly avoid installation of oxidation catalyst.

Low Load Considerations

As previously discussed and shown in Figures 8 and 9, emissions from existing SW501F CGTs at PEF Hines Energy Complex during low load operation are extremely high when compared to operation above 70 % load. The data shown in the graphs include startups, shutdowns, fuel switches, tunings and malfunctions. Emissions during periods of startups, shutdowns, and fuel switches, as well as during "idling" at less than full load, as they relate to this project are discussed below.

Startup and Shutdown

Simple Cycle Operation:

Frequent startups and shutdowns are expected of the Unit 5 simple cycle gas turbine, as well as the two CTs designated to operate in simple cycle mode during the slated "interim" period. Note that the emission levels in the graph in Figure 8 represent hourly averages. The Siemens SGT6-5000F in SC mode can be at baseload (Figure 11) and achieve low emissions within 30 minutes of initiation of startup.

It can also be seen from Figure 8 that emissions ramp up and peak at about 40 to 50 % load. Therefore, total emissions for a "startup" cycle would include a period at the beginning of startup with very low emissions, a period during the middle of startup with very high emissions, and the remainder of startup and the rest of the hour with normal levels of mass emissions. The actual hourly emission rate would therefore likely be lower than that implied by the graphs. Additionally, with the Siemens operational enhancements for improved startup capability and part load CO emissions reduction described earlier, startup emissions should be significantly reduced.

The CTGs of the combined cycle unit will be equipped with bypass stacks to allow for SC operation during periods such as steam turbine or main condenser failures. This mode will be used only to ensure reliability of the units and would naturally be minimized by the facility because of the lower efficiency realized in SC operation. Additionally, SC operation of the CTGs for this unit would require cooling of the ducting between the CTG and the HRSG in order to remove one plate and to install another to divert turbine exhaust gas (TEG) to the bypass stack. Operation under this scenario is expected to be very limited therefore the number of startups using the bypass stacks will be very low.

Combined Cycle Operation

For a CC 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. This can take several hours of low load operation. Following the slated "interim" period, Bartow Units 1 through 4 will primarily operate in continuous combined cycle mode. Although emissions from a CC startup will be significantly higher than that from a SC startup, it is expected that very few will actually occur. Typically cold startup of the steam turbine electrical generator (STG) occurs less than twice per year.

The above discussion focuses on unit startups. However, the same ideas can be applied to shutdowns which are generally of much shorter duration and account for significantly fewer overall emissions.

Operation Below Full Load Other Than Startup and Shutdown

During off-peak hours when demand for electricity is lowest, many CC units are often turned down to loads less than 100 % in order to conserve fuel and lower costs. Units 1 through 4 will be base loaded units and are normally expected to operate at, or near, 100 % load. However, these units will not be limited to full load operation, and even when operating at the lower loads they will be required to meet the CO emissions limits and demonstrate compliance by CEMS. According to Siemens, with the recent enhancements (if implemented), CO emissions of less than 10 ppm can be maintained at operation to between 45 and 50 % load.

Fuel Switching

The principal reason for increased emissions during fuel switching is generally the same as that for startup – low load operation. It is necessary to bring the CT to low load operation for a limited amount of time in order to switch from one fuel to the other. Each turbine will be limited to 1,000 hours of oil use as a back-up fuel. Fuel switching is expected to be infrequent, but will vary depending on fuel availability and cost.

<u>Fuel Oil Considerations</u>

Fuel oil firing is expected to be minimal but is actually requested for 1,000 hours per year per turbine. The annual potential to emit (PTE) CO emissions at 1,000 hours of operation at the requested BACT values is comparable to the annual PTE for the full time natural gas case, excluding power augmentation and duct burner operation.

The CO and VOC estimates given in Table 3 while firing fuel oil near full load are excessive and in contrast to the compliance tests conducted at the PEF Hines Energy Complex. Whereas limits of 30 ppmvd CO and 10 ppmvd VOC are requested for fuel oil firing for the Bartow units, the full load tests at Hines indicated emissions during all compliance runs less than 1.3 ppmvd and less than 0.4 ppmvd for the two pollutants respectively.[8] However, it is possible that CO emissions when firing fuel oil exhibit the same startup, shutdown and low load characteristics as discussed above.

Again, CO and VOC emissions while firing fuel oil near full load should be very low based on the high combustion temperature and the relatively high temperature and excess air in the TEG. It would appear that some of the possible design and operational remedies described by Siemens for the low load conditions while firing natural gas can also be employed for fuel oil firing.

Duct Burner Considerations

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,100 °F) and high excess air (> 12% O_2). In the design shown in Figure 7, some of the heat is used by the first part of the split high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering the second section (Component 6) of the split superheater.

The figure below shows an individual burner and an array comprising a duct burner. The hot TEG contains sufficient combustion air to burn the natural gas introduced into the burner array.

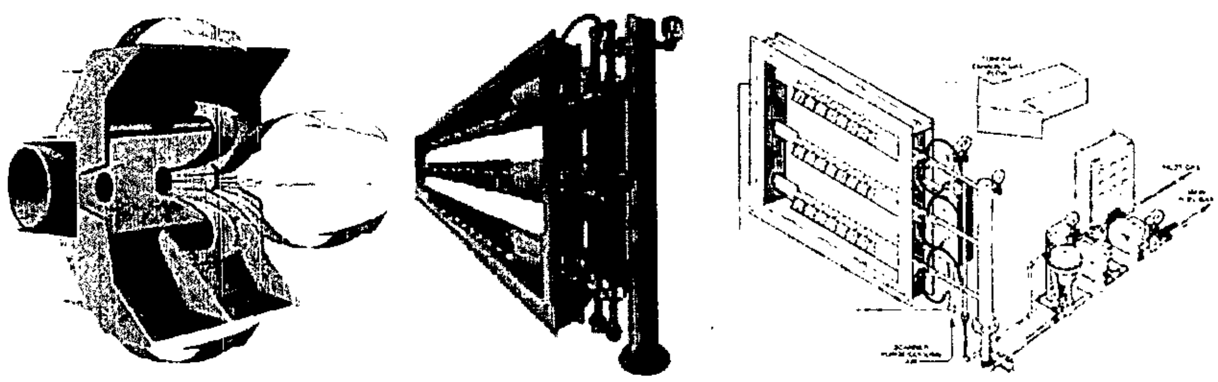

Figure 11 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions (oxygen, temperature, turbulence and time) are present to minimize CO and VOC concentration increases.

Following is a table with the results of CO and VOC testing completed at the Gulf Power Lansing Smith Plant[9] and OUC Stanton Unit A. The units are GE7FA combustion turbines (CT) that are the same-class competitor to the SGT6-5000F. Tests were conducted on each combustion turbine while using duct burners (DB). CO emissions increase slightly when firing duct burners, but still remain very low. No appreciable differences in CO emissions are noted for large combustion turbines when operating on fuel oil versus natural gas.

Table 4. CO and VOC Emissions while Duct Firing – GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CGT & DB)	1.21	0.15
Gulf Smith Unit 5 (CGT & DB)	1.26	0.31
OUC Stanton Unit 25 (CGT)	0.5	0.04
OUC Stanton Unit 26 (CGT)	0.5	0.49
OUC Stanton Unit 25 (CGT & DB)	1.6	0.2
OUC Stanton Unit 26 (CGT & DB)	1.6	0.26

Based on the full load CGT testing at PEF Hines Energy Complex and the fact that duct burners will be used at or near full load CGT operation, the Department would expect very low CO and VOC emissions at PEF Bartow when the duct burners are used.

Comparison of PEF's Initial CO and VOC BACT Proposal with Recent Projects

Following are some of the most recent BACT determinations by the Department for CO and VOC emissions from large CTGs. PEF's proposal is included in the table for comparison.

Table 5. Recent CO and VOC Standards for "F and G-Class" CTGs

Project Location	CO – ppmvd @15% O_2	VOC – ppmvd (@15% O_2)
PEF Bartow Application	4.0 – NG (baseload - 70%, CEMS) 10.0 – NG (70-60% load, CEMS) 9.0 – NG (DB on, CEMS) 30 – FO (baseload to 70%, CEMS)	1.0 – NG (baseload – 70%, Annual Test) 4 – NG (70-60% load, Annual Test) 2 – NG (DB on, Annual Test) 10 – FO (Annual Test)
FP&L Turkey Pt.	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 14 – 24-hr NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	1.3 – NG (DB off, Annual Test) 1.9 – NG (DB on, Annual Test) 2.8 – FO (Annual Test)
FP&L W. County	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	1.2 – NG (DB off, Annual Test) 1.5 – NG (DB on, Annual Test) 6 – FO (Annual Test)

Table 5 (Cont). Recent CO and VOC Standards for "F and G-Class" CTGs.

Project Location	CO – ppmvd @15% O_2	VOC – ppmvd (@15% O_2)
FMPA Treasure Coast	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	Not PSD
PEF Hines 4	8.0 – NG (24-hr block) 12.0 – FO (24-hr block)	1.3 – NG (Annual Test) 3.0 – FO (Annual Test)

Notes: NG = CT on Natural Gas DB = Duct Burner FO = Fuel Oil

Department's CO and VOC BACT Determination

Based on data and information available to the Department as presented in the above discussion, the following conclusions can be drawn:

- PEF's proposed CO emission limit for normal operation (gas firing, 70-100 % load, DB off) of 4.0 ppmvd @ 15% O_2 is acceptable and consistent with similar unit experience at the PEF Hines Energy Complex. However, the proposed limits for less than 70 % load, duct burner operation, and fuel oil firing as listed in Table 3 are excessive and in contrast to compliance test results on similar units.
- There will be considerable use of duct burners (DB). The Department believes CO emissions under DB in terms of ppmvd @15% O_2 will be approximately equal to emissions under the normal mode. PEF still estimates greater CO concentrations while using the duct burners than when operating the combustion turbine at full load. The requested value of 9.0 ppmvd @15% O_2 for this mode of operation is slightly higher than other recent BACT determinations of 7.6.
- The CO proposal of 30 ppmvd @15% O_2 while firing fuel oil appears very high when compared to past experience on existing units and other recent proposals for new units. The expectation is that CO emissions during periods of fuel oil firing will be similar to emissions during gas firing.
- PEF's proposed VOC emissions limits are similarly high for periods of duct burner operation and fuel oil firing. The same discussions presented above apply, and actual emissions of VOCs are expected to be considerably lower than proposed during these modes of operation.

The applicant has determined that CO oxidation catalyst is not cost effective for this project. According to PEF, estimated capital cost per CT is $1,422,634 and total annualized cost per CT is $688,966 resulting in a cost effectiveness of $3,956 per ton of CO removed assuming an 80% reduction in CO emissions. The Department however, does not agree with all aspects of the applicant's determination and feels that CO catalyst would be cost effective if necessary to comply with all BACT limits.

For example, capital and replacement costs are slightly lower in an independent budgetary proposal obtained by the Department for a CO catalyst system on a GE 7FA unit, than those proposed by PEF. The Department's Engelhard catalyst performance guarantee includes a maximum pressure drop across the catalyst of 0.9 to 1.0 inches water gauge (WG). The applicant's proposed cost effectiveness analysis was based on a maximum pressure drop of 1.5 to 2.0 WG. Additionally, based on experience with existing units a minimum 5-year expected catalyst life is a better representation of real-life expectations than the 3-years assumed by PEF.

PEF updated the heat rate penalty to reflect a more recent natural gas cost as requested by the Department. A cost of $9.6/MMBtu was used for the new estimate. Although this may have been the instantaneous price at the time the estimate was updated, considering the recent overall trend in natural gas prices the amount chosen may be unnecessarily high. For the last week of November prices were in the $8.00/MMBtu range.

For a more long-term look, the recently published 2007 Annual Energy Outlook presents a midterm forecast and analysis of US energy supply, demand, and prices through 2030[10]. The projections are based on results from the *Energy Information Administration's* National Energy Modeling System. The following table is an excerpt from the DOE report showing natural gas price projections in the $5 and $6 per MMBtu range through 2025. Expansion of existing and construction of new liquefied natural gas (LNG) terminals is the main reason for the long term stability in the future.

Table 6. Energy Prices by Sector and Source (2005 Dollars per Million Btu)

Sector and Source	**Reference Case**					
	2004	**2005**	**2010**	**2015**	**2020**	**2025**
Electric Power						
Distillate Fuel Oil	9.52	11.38	11.71	9.26	9.84	10.25
Residual Fuel Oil	4.99	6.96	6.58	5.60	6.08	6.58
Natural Gas	**6.11**	**8.18**	**6.22**	**5.50**	**5.76**	**6.05**
Steam Coal	1.40	1.53	1.71	1.60	1.58	1.63

CO and VOC limits consistent with recent BACT determinations issued by the Department will be set for PEF Units 4 and 5. These limits should be readily met without the use of oxidation catalyst systems assuming fast startups and high load operation. Each HRSG stack will be equipped with a CO CEMS, and a reasonable continuous 24-hour emissions limit will be set to cover all modes of operation. This is consistent with recent determinations for FPL Turkey Point and FMPA Treasure Coast combined cycle projects. If additional measures are needed in the future to meet the CO emission limits due to extended low load operation by the CC unit 4 CTs, then oxidation catalyst will be a cost effective alternative control strategy.

Because full load is quickly reached, and operation will be limited to loads greater than 70 % during simple cycle operation, oxidation catalyst is not a consideration for the Unit 5 CT nor will it be required prior to the bypass stacks on Unit 4. Simple cycle operation of the Unit 4 CTs is expected to be minimal. Compliance determinations with the CO standards during simple cycle operation will be based on required stack tests.

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 7. Draft BACT Determination

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

b. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

5. NEW SOURCE PERFORMANCE STANDARDS APPLICABLE TO GAS TURBINES AND DUCT BURNERS

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart KKKK of 40 CFR 60. These requirements result in the following standards for the proposed CTs. Subpart KKKK also applies to emissions from any associated HRSG and duct burners.

- NO_X (gas) $\leq$ 15 ppm @ 15% O_2 or 0. 43 lb/MWh (4-hr average);
- NO_X (oil) $\leq$ 42 ppm @ 15% O_2 or 1.3 lb/MWh (30 operating day average); and
- $SO_2 \leq$ 0.90 lb/MWh or $\leq$ 0.060 lb SO_2/MMBtu*

*Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring by demonstrating sulfur content of no more than 0.05% (500 ppmw) by weight fuel oil or 20grains of sulfur per 100 standard cubic feet of natural gas.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS APPLICABLE TO GAS TURBINES

The Bartow Power Plant is an existing source of hazardous air pollutant emissions. As such, the proposed new combustion turbines will be subject to NESHAP Subpart YYYY- National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, which became final on March 5, 2004.[11]

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[12] EPA has stayed the applicability of YYYY to certain gas-fired units and proposed to permanently delete such units (as well as other classes) from the list of sources subject to the regulation.

For a stationary combustion turbine to qualify as a gas-fired unit under Subpart YYYY each stationary combustion turbine which is equipped both to fire gas and oil, must be located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

Because the CTs for this project will have the potential for an aggregate oil-firing total significantly greater than 1,000 hours (up to 5,000 hours) during any calendar year, initial compliance with the applicable YYYY standard must be determined upon startup. Applicability thereafter will be based upon actual aggregate fuel oil use during any calendar year.

Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

PEF proposes to meet the limit proposed in YYYY of 91 ppbvd. The Department believes the formaldehyde emission limit will be met given the BACT CO limits of 8.0 and 6 ppmvd @15% O_2 for daily and annual operation respectively. It is also expected that the units will easily demonstrate compliance with the formaldehyde limit during the initial and annual test requirements.

7. PERIODS OF EXCESS EMISSIONS

Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "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." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from PEF regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases:

- For the very infrequent oil-to-gas and gas-to-oil fuel switching, excess emissions shall not exceed 2 hour in any 24-hour period.

- Steam turbine startups occur as little as once during a ten-year period. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 8 hours in any 24-hr period. A cold startup of the "steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown lasting at least 48 hours.
- CT/HRSG startups are infrequent but occur more often than steam turbine startups. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed 4 hours in any 24-hr period. A cold startup of a "gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one–hour period. Short startup is enhanced by the use of the auxiliary steam generators that assist in heating surfaces and provide high quality steam for transition piece and nozzle cooling.
- For startup of a CT for the purpose of operation in simple cycle mode, excess emissions shall not exceed 1 hour in any 24-hour period.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.
- Dry Low NO_X combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NO_X and CO emissions, and extends the life of the unit components. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short, and once tuned, the gas turbine emissions will be minimized. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Other minor tuning sessions are expected to occur periodically on an as needed basis between major tuning sessions. The permit will require notification prior to any tuning session.

While CO and NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation.

8. BACT DETERMINATIONS FOR THE AUXILIARY BOILER

One gas-fired auxiliary boiler is required for the combined cycle unit system. The primary purpose of the auxiliary boiler is to assist in combined cycle startup by providing steam for combustor cooling until steam of sufficient quality can be provided by the HRSG.

The specifications for the auxiliary boiler are as follows:

- Nebraska Boiler or equivalent;
- Usage of up to 1,000 hours per year;

- Maximum heat input rate of 99 mmBtu/hr heat input; and
- Steam capacity: 85,000 lb/hr.

A recent BACT determination was conducted for the Port Westward, Oregon project. An auxiliary boiler was required for startup of an M501G combined cycle unit. A 91 MMBtu auxiliary boiler was specified for that project.

The state of Oregon conducted a search of BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC) in early 2005. Approximately 20 RBLC determinations were reviewed by the State of Oregon for auxiliary boilers in the range of 10 to 100 MMBtu/hr that are used in support of combined cycle projects. Separate tables were developed for CO and VOC as well as NO_X, SO_2, and PM/PM_{10}.

The ranges from the Oregon survey are presented in the following table along with limits from other projects for which the auxiliary boiler limits are known. Emissions performance estimates provided by PEF for the auxiliary boiler are included for comparison. NSPS and NESHAP requirements that are applicable to the auxiliary boilers are also included.

Table 8. CO and VOC Standards – Auxiliary Boilers for Combined Cycle Units

Project Location	**CO (lb/MMBtu)**	**VOC lb/MMBtu**
RBLC Survey	0.016 – 0.15	0.004 – 0.018
Port Westward, OR	0.08	0.005
Sithe Mystic, MA	0.08	0.008
Sithe Fore River, MA	0.08 and 100 ppm @3% O_2	0.008/0.004 (NG/FO)
Covert Generating, MI		
Progress Bartow (Application)	**0.08**	**0.01**
NSPS Subpart Dc	Boilers between 10 and 100 mmBtu/hr - Record Keeping Required	
NESHAP Subpart DDDD	400 ppm@3% O_2	

Notes: NG = Natural Gas FO = Fuel Oil

The CO and VOC performance values submitted by PEF for this project are similar to the projects in the Oregon survey and the other combined cycle projects listed above. The auxiliary boiler for this project will be used for the same purpose as those in the other projects.

The Department will set a CO BACT limit of 0.08 lb/MMBtu and operation of no more than 1,000 hours per year for the auxiliary boiler. The Department believes this is at least as stringent as, and possibly more stringent than, the applicable NESHAP standard of 400 ppm @ 3% O_2. This value can be achieved by numerous suppliers by good combustion techniques without resorting to catalysts. In a recent BACT determination conducted by the Washington State Energy Facility Site Evaluation Council for a similar unit, cost effectiveness for CO oxidation catalyst was estimated to be $16,227 per ton of CO. Emissions of VOC from the auxiliary boiler are estimated by PEF to be less than 0.5 TPY. A requirement for the exclusive use of natural gas and a 10 % opacity limit will ensure low emissions of VOC.

9. BACT DETERMINATIONS FOR NATURAL GAS-FIRED FUEL HEATERS

Five fuel heaters are required for the project. The purpose of these units is to heat natural gas above dew point temperatures and prevent condensation. The fuel heaters will be fired with natural gas only.

PEF included, as an example, specifications for the gas heaters as follows:

- Hannover Compression Company or equivalent;
- Continuous use although actual use will be much less; and
- Maximum heat input rate of 3 MMBtu/hr heat input.

Table 9. PEF Emission Estimates from Each Natural Gas-fired Fuel Heater

SO_2	NO_X	CO	VOC	PM
2 gr/100 SCF	100 lb/MMscf	84 lb/MMscf	5.5 lb/MMscf	1.9 lb/MMscf

Small gaseous fuel process heaters ($\leq$ 10 MMBtu/hr) are not subject to Subpart DDDDD. Annual emissions from all 5 heaters of CO and VOC are estimated by PEF to be 5.3 and 0.35 tons per year respectively.

The BACT limit for the fuel heaters will be the same as the auxiliary boiler: 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit will ensure low emissions of VOC. Hours of operation are not limited.

10. BACT DETERMINATIONS FOR THE EMERGENCY FIRE PUMP ENGINE

Progress proposes a 300 HP Clarke/John Deere diesel emergency fire pump. Such engines are regulated under 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

The standards vary depending on the size of the engine. The standards for engines from model year 2007 are given in the following table that are applicable to the emergency engine proposed for this project:

Table 10. EPA Emergency Fire Pump Standards, grams/bhp-hr

Size (hp)	CO	NMHC+NO_X	PM
175 and greater	2.6	7.8	0.40

Notes: bhp = brake horse power NMHC non-methane hydrocarbons

The Department's BACT for this emergency fire pump is compliance with the NSPS standards and use of 0.05% sulfur fuel oil.

11. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will increase emissions of two pollutants at levels in excess of PSD significant amounts: CO and VOC. CO is a criteria pollutant and has AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for VOC. VOC is an ozone precursor and any net increase of 100 tons per year requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

Major Stationary Sources in Pinellas County

The current largest stationary sources of air pollution in Pinellas County are listed below. The information is from annual operating reports submitted to the Department.

Table 11. Largest Sources of NO_X in Pinellas County (2005)

Owner	Site Name	TPY
Progress Energy	Bartow Power Plant (before repowering)	4210
Progress Energy	***Bartow Power Plant (proposed repowering)***	***3191***
Pinellas Board of Co Comm.	Pinellas Co Resource Recovery Facility	1447
Florida Power/Progress	Bayboro Power Plant	337
Florida Power/Progress	Higgins Plant	151

Table 12. Largest Sources of SO_2 in Pinellas County (2005)

Owner	Site Name	TPY
Progress Energy	Bartow Power Plant (before repowering)	16,462
Progress Energy	***Bartow Power Plant (proposed repowering)***	***466***
Pinellas County	Pinellas County Resource Recovery Facility	39

Table 13. Largest Sources of PM in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	Bartow Power Plant (before repowering)	495
Progress Energy	***Bartow Power Plant (proposed repowering)***	***413***
Pinellas County	Pinellas County Resource Recovery Facility	33
Progress Energy	Bayboro Power Plant	4

Table 14. Largest Sources of CO in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	***Bartow Power Plant (proposed repowering)***	***938***
Progress Energy	Bartow Power Plant (before repowering)	369
Pinellas County	Pinellas County Resource Recovery Facility	121
Progress Energy	Higgins Plant	39

Table 15. Largest Sources of VOC in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	***Bartow Power Plant (proposed repowering)***	***145***
Cardinal Health	Cardinal Health PTS, LLC	110
Hydro Spa	Hydro Spa – Clearwater	60
Times Publishing Co.	St. Pete Times Printing Plant	58
Progress Energy	Bartow Power Plant (before repowering)	57
Lifoam Industries	Lifoam Industries	54

Air Quality and Monitoring in Pinellas County

Pinellas County Department of Environmental Management operates twenty-three monitors at fourteen sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, NO_2, lead, toxics and SO_2. The 2006 monitoring network is shown in the figure below.

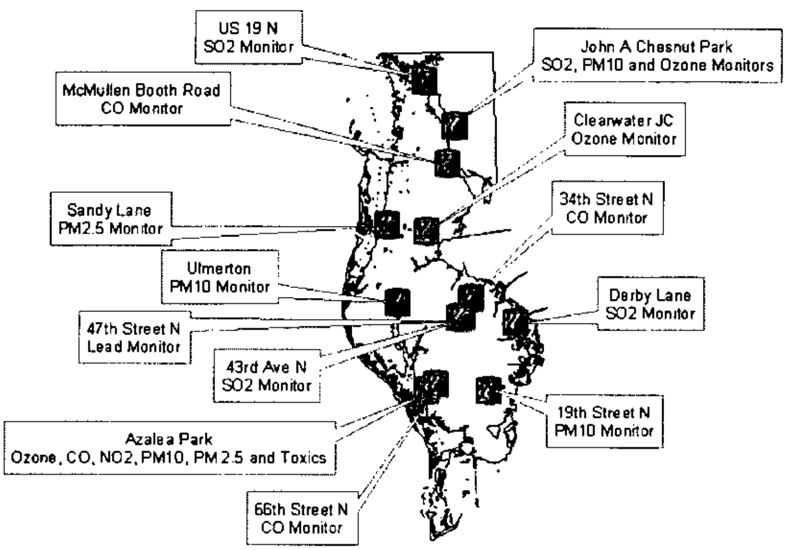

Figure 12. Pinellas County DEM Ambient Air Monitoring Network

Measured ambient air quality information is summarized in the following table.

Table 16. Ambient Air Quality in Pinellas County Nearest to Project Site (2005)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Ulmerton	24-hour	44	40		150 [a]	ug/m^3
		Annual			21	50 [b]	ug/m^3
SO_2	Derby Lane	3-hour	75	59		500 [a]	ppb
		24-hour	32	24		100[a]	ppb
		Annual			3	20 [b]	ppb
NO_2	Azalea Park	Annual			8	53 [b]	ppb
CO	34th Street N	1-hour	3	3		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Clearwater JC	1-hour	.090	.088		0.12 [C]	ppm
		8-hour	.076	.074		0.08 [C]	ppm

* The Mean does not satisfy summary criteria due to missing data.
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

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels, at least at the monitoring locations. One exception is ozone because it is formed from precursors (NO_X and VOC) that are available from local industrial and transportation emissions. The tendency to form ozone is accentuated by hot ambient temperature, solar insulation, high pressure, and relatively low wind speed.

Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for CO. A significant impact analysis is performed on this pollutant to determine if the proposed project can cause an increase in ground level concentrations greater than the SILs for CO. The applicant also performed a significant impact analysis for the Class II area for other PSD pollutants that will decrease as a result of the project or increase by values less than their respective significant emission Rates (SERS). The pollutants are SO_2, PM_{10} and NOX. The additional analysis was performed to ensure compliance with National Ambient Air Quality Standards.

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 models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class II Areas (everywhere except the Chassahowitzka National Wildlife Refuge).

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 the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 4 kilometers from the facility. From 4 to 6 kilometers, Cartesian receptors with a spacing of 500 meters were used. From 6 to 10 kilometers, Cartesian receptors with a spacing of 1000 meters were used.

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except CNWR) for Phase I (2 combustion turbines in simple cycle mode). The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except CNWR) except for non-PSD SO_2, 24-hour PM_{10} and NOx for Phase 2 (4 combustion turbines in combined cycle mode, 1 simple cycle). These values are tabulated in the tables below and are compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 17. Maximum Projected Air Quality Impacts from Progress Bartow for Comparison to the PSD Class II Significant Impact Levels – Phase I

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations – 2005 Data (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	8	60	NO
	24-Hour	4.7	5	83	260	NO
	3-Hour	14	25	195	1300	NO
PM_{10}	Annual	0.1	1	21	50	NO
	24-Hour	3.5	5	44	150	NO
CO	8-Hour	17.9	500	2,300	10,000	NO
	1-Hour	39.7	2000	3,450	40,000	NO
NO_2	Annual	0.5	1	15	100	NO

It is clear that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area for Phase I. SO_2, PM_{10}, CO and NO_X are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

Table 18. Maximum Projected Air Quality Impacts from Progress Bartow for Comparison to the PSD Class II Significant Impact Levels – Phase II

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations – 2005 Data (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	2	1	8	60	YES
	24-Hour	29	5	83	260	YES
	3-Hour	80	25	195	1300	YES
PM_{10}	Annual	0.9	1	21	50	NO
	24-Hour	24	5	44	150	YES
CO	8-Hour	108	500	2,300	10,000	NO
	1-Hour	153	2000	3,450	40,000	NO
NO_2	Annual	5	1	15	100	YES

Maximum predicted impacts from the project for CO (PSD pollutant) are much less than the respective AAQS and the baseline concentrations in the area for Phase II. However, maximum predicted impacts from the project for SO_2, PM_{10} and NOx (non-PSD) are much greater than the SILs but still much lower than the respective AAQS in the area for Phase II. CO is also less than the respective significant impact levels that would otherwise require more detailed modeling efforts. Although SO_2, PM_{10} and NOx are not subject to PSD and the project will ultimately improve air quality in the County with regards to these pollutants, the applicant provided further, more detailed multi-source modeling to ensure compliance with PSD Increments and National and State Ambient Air Quality Standards.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for CO was less than this de minimis level. Therefore, no pre-construction monitoring is required for CO.

Table 19. Maximum 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?
CO	8-hour	108	575	2,300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential net VOC emissions from the repowering project to be 88 tons per year. Therefore, preconstruction monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project is the following:

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA November 2005 and will officially replace the ISCST3 model December 2006. During this "transition" time period from November 2005 to December 2006, both the ISCST and AERMOD model may be used. This "transition" will allow applicants and the Department to assimilate AERMOD guidance and procedures.

The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

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.

AERMET Meteorological data prepared by the Department and used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the Tampa International Airport and twice-daily upper air soundings from the National Weather Service at Ruskin. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, 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 should EPA revise 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.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I CNWR beyond 50 km from the proposed project. Meteorological data used in this model was from 2001 through 2003.

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, is 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 mechanism.

Multi-source PSD Class II Increment Analysis

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. The maximum predicted Class II area impacts from this project and all other increment-consuming sources in the vicinity of the Bartow Power Plant are shown in the following table.

Table 20. PSD Class II Increment Analysis (not required, pollutants not subject to PSD)

Pollutant	Averaging Time	2nd Highest-High All Sources Max Predicted Impact (μg/m³)	Allowable Increment (μg/m³)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	24	30	NO
PM_{10}	Annual	0.3	17	NO
SO_2	24-hour	36	91	NO
SO_2	3-hour	93	`512	NO
SO_2	Annual	0	20	NO
NOx	Annual	3	25	NO

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.

Table 21. Ambient Air Quality Impacts (Background Highest of 2004-05)

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	27.4	80	107	NO	150
PM_{10}	Annual	2.2	29	32	NO	50
SO_2	24-hour	137	86	223	NO	260
SO_2	3-hour	464	267	731	NO	1300
SO_2	Annual	24	5	29	NO	60
NO_2	Annual	8	17	25	NO	100

Ozone

Ozone is an area-wide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

The Bartow Repowering Project will have net reductions of 852 TPY of NO_X. Less than 100 TPY of VOC will be added, which is an increase of less than 1% in the region. Although a minimal amount of VOC will be added, the reduction of NOx should have a positive result in reducing total ozone in the area.

In the near future, many existing power plants and other industries in Florida that contribute to visibility impairment will reduce emissions of NO_X and SO_2 pursuant to the Clean Air Interstate Rule (CAIR) and the requirements of Best Available Retrofit Technology (BART). These NOx reductions will also contribute to decreasing ozone formation.

Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Substantial net emissions reductions for sulfuric acid mist, SO_2, PM_{10} and NO_X will help ameliorate past air pollution effects on soils, vegetation and wildlife.

The maximum ground-level concentrations predicted to occur for CO as a result of the proposed project will be considerably less than the respective AAQS. According to the applicant, plant species most sensitive to CO showed cellular damage when exposed to 685,000 micrograms per cubic meter of CO. The applicant modeled CO impacts in the Chassahowitzka Class I area. The highest modeled impact from the proposed repowering was 3.44 micrograms per cubic meter of CO.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. Clearly, with net reductions of sulfur and nitrogen, the deposition of pollutant from Bartow in the Class I area will be less than current levels.

Impact on Visibility:

There will be significant visibility improvements in the immediate vicinity because of the reduction of particulate emissions from the repowered plants and the very significant reductions in condensable and fine particulate precursors. The existing units are subject to opacity limitations of 40 percent under present normal operation whereas the replacement units will be subject to a 10% opacity standard.

Regional Haze in the Chassahowitzka National Wildlife Refuge will experience some improvement as well due to reduced emissions of ozone precursors and fine particulate precursors.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 300 additional workers will be needed over the 31-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the new facility will require no new permanent employees, which will cause no impact on the local area.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, there has been little growth in the area of the Bartow facility since 1977. However, according to the Census, the population of Pinellas County has increased from 728,531 in 1980 to 921,482 in 2000. In 2000, Pinellas County was the most densely populated county in Florida. Despite population growth, the air quality has remained fairly constant. The chart below shows the Air Quality Index, an index of daily air quality, for Pinellas County over twelve years. With the exception of a few years around 1990, the index has remained close to 300 "Good" days while experiencing no days in the "Unhealthy" categories despite a growth of approximately 80,000 people.

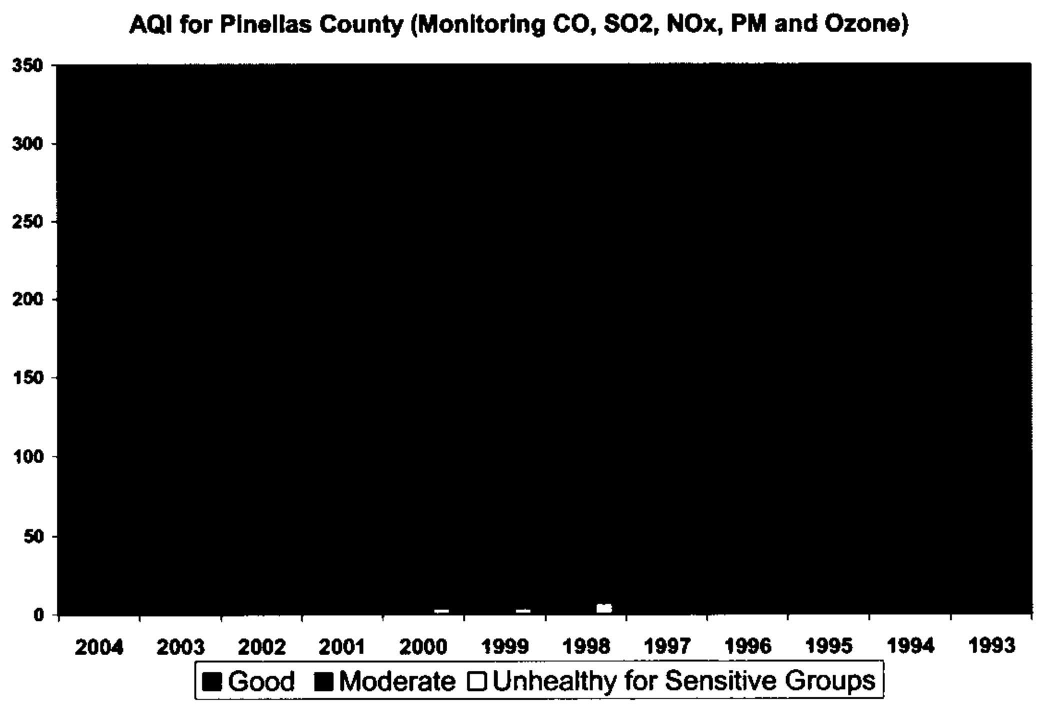

Figure 13. Pinellas County Air Quality Index History.

12. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Teresa Heron is responsible for reviewing the application, and preparing the draft permit. She may be contacted at teresa.heron@dep.state.fl.us and 850-921-9529. Alvaro Linero is the project engineer responsible for preparing the draft BACT determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

References

1 Technical Progress Report. Castaldini, C., CMC-Engineering. *Guidelines for Combustor Dynamic Pressure Monitoring,* EPRI, Palo Alto, CA, 2004. Product ID: 1005036

2 Paper. Xia, J., et al. SGT6-5000F (W501F) Engine Enhancements to Improve Operational Flexibility. POWER-GEN International 2005. Las Vegas, Nevada. December 6-8, 2005.

3 Test Report. Cubix Corporation. Initial Compliance Test Report for Natural Gas Fueled Stack Emissions on Westinghouse 501F Combined Cycle Turbines. Power Block 1 – PEF Hines Energy Complex Power Block 1. February 1999.

4 Letter. FDEP to PEF. P.L. Bartow Power Plant Repowering Project - Request for Additional Information. August 30, 2006.

5 Response Letter. PEF to FDEP. P.L. Bartow Power Plant Repowering Project - Request for Additional Information. September 29, 2006.

6 Response Letter. PEF to FDEP. Hines Energy Complex. Title V Permit Revision. August 31, 2006.

7 Paper. Xia, J., et al. SGT6-5000F (W501F) Engine Enhancements to Improve Operational Flexibility. POWER-GEN International 2005. Las Vegas, Nevada. December 6-8, 2005.

8 Test Report. Cubix Corporation. Initial Compliance Test Report for No. 2 Fuel Oil Fueled Stack Emissions on Westinghouse 501F Combined Cycle Turbines. Power Block 1 – PEF Hines Energy Complex Power Block 1. May 1999.

9 Letter. Waters, G.D., Gulf Power to Halpin, M.P., FDEP. Lansing Unit Units 4 & 5 Test Results. May 6, 2001.

10 Report. U.S. Department of Energy, Annual Energy Outlook 2007 (Early Release), Report #DOE/EIA-0383(2007), released December 2007. http://www.eia.doe.gov/oiaf/aeo/index.html

11 Final Rule. National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Federal Register / Vol. 69, No. 44 / Friday, March 5, 2004. Pages 10512 – 10548.

12 Proposed Rule. National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Federal Register Vol. 69, No. 67, April 7, 2004. Pages 18327 – 18343.

SECTION 4. APPENDICES

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GENERAL PROVISIONS, SUBPART A FOR NSPS AND NESHAP

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

Refer to the Draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

Emissions from each gas turbine shall not exceed the values given in the following table.

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

b. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

Department's DRAFT BACT Summary for Auxiliary Boiler and Gas Heaters

The CO BACT limit for the fuel heaters and the auxiliary boiler is 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit is BACT for VOC.

Department's DRAFT BACT Summary for Emergency Fired Pump

The Department's BACT for the emergency fire pump (175 HP or greater) is compliance with the NSPS standards for CO and VOC and use of 0.05% sulfur fuel oil.

SECTION 4. APPENDIX GC

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.
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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
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.
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.
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.
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.
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.
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.

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.

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.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with New Source Performance Standards (X); and
    d. Compliance with National Emission Standards for Hazardous Air Pollutants for Source Categories (X).

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.

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.

COMMON CONDITIONS

{Permitting Note: Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the 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 Allowed: 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. [Rule 62-210.700(1), F.A.C.]

4. 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.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

9. 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

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. 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.]

12. 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.]

13. 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.]

14. 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.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. 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.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the

test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. 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.]
20. 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.]

NSPS SUBPART Dc PROVISIONS

A 99 MMBTu/hr (85,000 lb/hr) auxiliary boiler will serve the combined cycle unit system to produce steam during start up of the CTs. The auxiliary boiler is regulated as Emissions Unit 014. The provisions of this Subpart may be provided in full upon request.

{Note: Only applicable definitions have been included.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbines shall comply with the applicable federal requirements. These combustion gas turbines are regulated as Emissions Units 009, 010, 011, 012 and 013.

Source: Federal Register dated 7/6/06

Introduction
60.4300 What is the purpose of this subpart?

Applicability
60.4305 Does this subpart apply to my stationary combustion turbine?
60.4310 What types of operations are exempt from these standards of performance?

Emission Limits
60.4315 What pollutants are regulated by this subpart?
60.4320 What emission limits must I meet for nitrogen oxides (NOX)?
60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

General Compliance Requirements
60.4333 What are my general requirements for complying with this subpart?

Monitoring
60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?
60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?
60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
60.4355 How do I establish and document a proper parameter monitoring plan?
60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
60.4370 How often must I determine the sulfur content of the fuel?

Reporting
60.4375 What reports must I submit?
60.4380 How are excess emissions and monitor downtime defined for NOX?
60.4385 How are excess emissions and monitoring downtime defined for SO2?
60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
60.4395 When must I submit my reports?

Performance Tests
60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?
60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?
60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

Definitions
60.4420 What definitions apply to this subpart?

Table 1 to Subpart KKKK of Part 60-Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

The combustion gas turbines are subject to the applicable requirements of the 40 CFR 63, Subpart YYYY. The provisions of this Subpart may be provided in full upon request. These combustion gas turbines are regulated as Emissions Unit 009, 010, 011, 012 and 013.

Applicability of NESHAP Subpart YYYY

The Bartow Power Plant is a major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the West County Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

NESHAPS REQUIREMENTS FOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS

The auxiliary 99 MMBtu/hr boiler and the process heaters are subject to the applicable requirements of this 40 CFR 63, Subpart DDDDD. These emission units are regulated as E.U. 014 and 015 respectively. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register Dated 9/12/04

Tables to Subpart DDDDD of Part 63
Table 1 to Subpart DDDDD of Part 63--Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63--Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63--Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63--Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63--Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63--Reporting Requirements
Table 10 to Subpart DDDDD of Part 63--Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD
Appendix A to Subpart DDDDD--Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B to Subpart DDDDD--Applicability of General Provisions to Subpart DDDDD

The emergency fired pump is subject to the applicable requirements of 40 CFR 60, Subpart IIII. This unit is regulated as emissions unit (E.U.) 017. The provisions of this Subpart may be provided in full upon request.

Source Federal Register Dated 7/11/06. EFECTIVE 9/11/06

Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

General Provisions

60.4218 What parts of the General Provisions apply to me?

Definitions

60.4219 What definitions apply to this subpart?

Tables to Subpart IIII of Part 60

Table 1 to Subpart IIII of Part 60--Emission Standards for Stationary Pre-2007 Model Year Engines with a displacement of < 10 liters per cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and with a displacement of < 10 liters per cylinder

Table 2 to Subpart IIII of Part 60--Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE < 37 KW (50 HP) and with a Displacement of < 10 liters per cylinder

Table 3 to Subpart IIII of Part 60--Certification Requirements for Stationary Fire Pump Engines

Table 4 to Subpart IIII of Part 60--Emission Standards for Stationary Fire Pump Engines

Table 5 to Subpart IIII of Part 60--Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

Table 6 to Subpart IIII of Part 60--Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

Table 7 to Subpart IIII of Part 60--Requirements for Performance Tests for Stationary CI ICE with a displacement of >=30 liters per cylinder

Table 8 to Subpart IIII of Part 60--Applicability of General Provisions to Subpart IIII

SECTION 4. APPENDIX XS
SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer: ____________________

Model No.: ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____________________

Total source operating time in reporting period [1]: ____________________

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ %[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

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

Note: On a separate page, describe any changes since the last in CMS, process or controls.

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

Name: ____________________

Signature: ____________________ *Date*: ____________________

Title: ____________________