FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 6, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert K. Alff, Senior Vice President
Calpine Construction & Finance Company, L.P.
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Re: DEP File No. PA 00-42 (PSD-FL-309)
Blue Heron Energy Center
1080 Megawatt Electric Power Plant

Dear Mr. Alff:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Blue Heron Energy Center to be located approximately 5 miles southwest of Vero Beach in Indian River County. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

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

CHF/mph

Enclosures

P.E. Certification Statement

Calpine Construction & Finance Company, L.P.
Blue Heron Energy Center
Indian River County

DEP File No.: PSD-FL-309
Facility ID No.: 0610082

Project: Air Construction Permit

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

(Seal)

Michael P. Halpin

Michael P. Halpin, P.E.
Registration Number: 31970

1-26-01
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

In the Matter of an
Application for Permit by:

Mr. Robert K. Alff, Senior Vice President
Calpine Construction & Finance Company
The Pilot House, 2nd Floor, Lewis Wharf
Boston, MA 02110

Facility I.D. No. 0610082
DEP File No. PA 00-42 (PSD-FL-309)
1080 MW Electric Power Plant
Blue Heron Energy Center
Indian River County

INTENT TO ISSUE PSD PERMIT

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

The applicant, Calpine Construction & Finance Company, L.P., applied on December 5, 2000 to the Department for a PSD permit to construct a 1080 megawatt combustion turbine based electrical power generating plant consisting of: four nominal 170 MW "F" class combustion turbine-electrical generators; four supplementally fired heat recovery steam generators capable of raising sufficient steam to generate another 400 MW from two steam-electrical generators; three mechanical draft cooling towers; four 135 foot stacks; and ancillary equipment. The project will be located approximately 5 miles southwest of Vero Beach in Indian River County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit and a determination of Best Available Control Technology for the control of carbon monoxide, nitrogen oxide, sulfur dioxide, sulfuric acid mist, particulate matter, and volatile organic compounds, is required to conduct the work.

The Department intends to issue this PSD 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. and 40 CFR 52.21.

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 PSD Permit." The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. 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). The Department suggests that you publish the notice within thirty days of receipt of this letter. 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 or other authorization. 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 and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) 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 hearing (meeting) concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue PSD permit." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

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

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

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

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

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

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT PSD permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/7/01 to the person(s) listed:

Mr. Robert K. Alff, Calpine *
Mr. Tim Eves, Calpine
Mr. Tom Davis, P.E., ECT
Mr. David Dee, Landers and Parsons
Mr. Len Kozlov, DEP-Central District
Chair, Indian River County Commission *
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA
Mr. Hamilton S. Oven, DEP-Siting
Audobon of Florida *
Pelican Island Audobon Society *

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 2/7/01
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero *aaf*

FROM: Michael P. Halpin *MPH*

DATE: January 26, 2001

SUBJECT: Calpine Construction & Finance Company, L.P.
Blue Heron Energy Center, a 1080 MW Electric Power Plant
DEP File No. PA 00-42 (PSD-FL-309)

Attached is the public notice package for construction of a natural gas-fired (combined cycle), 1080 MW (nominal) generating plant to be named the Blue Heron Energy Center. The facility will consist of four Westinghouse "F" frame combustion turbines, each with a supplementally fired HRSG for use with two 200 MW steam turbines. It will be located approximately 5 miles SW of Vero Beach, near I-95.

This project will equal the lowest emissions of NO_X (per megawatt) which we've permitted for any generating plant in this state, approximately 0.1 lb per MWH. The permit (as drafted) allows for NO_X emissions of 3.5 ppmvd on a 3-hour block average (via SCR). Additionally, the permit (as drafted) will require a CEMS for the continuous measurement of CO emissions, which will be based upon a 24-hour block average. Lastly, ammonia slip emissions of only 5 ppmvd are allowed, also meeting the lowest value that we have thus far permitted.

Although PM emissions required a close evaluation due to the cooling towers, emissions of sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently clean pipeline quality natural gas with no fuel oil usage.

It is my understanding that Calpine has prospective buyers for (at least portions of) the output from this facility. It is therefore possible that the recent Supreme Court decision (re: Duke New Smyrna) may not negatively impact the prospect of the Blue Heron facility receiving its Power Plant Certification.

Accordingly, I recommend your approval of the attached Intent to Issue for the PSD permit.

AAL/mph

Attachments

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PA 00-42
PSD-FL-309
Calpine Construction & Finance Company, L.P.
1080 Megawatt Electric Power Plant
Indian River County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to Calpine Construction & Finance Company, L.P. The permit is to install a gas-fired power plant referred to as Blue Heron Energy Center, approximately 5 miles southwest of Vero Beach, in Indian River County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), volatile organic compounds (VOC) sulfur dioxide (SO_2) and sulfuric acid mist (SAM). The applicant's name and address are Calpine Construction & Finance Company, L.P., The Pilot House, 2nd Floor, Lewis Wharf, Boston, MA 02110.

The project consists of four nominal 170 megawatt Siemens Westinghouse 501FD gas-fired combustion turbine-generators, which may be operated with duct-fired heat recovery steam generators (HRSGs) that will raise sufficient steam to produce approximately another 400 MW via a steam-driven electrical generator. The gas turbines and duct burners will fire only natural gas. The project also includes 3 cooling towers; a diesel-fired emergency generator; a diesel fire pump; four stacks and ancillary equipment.

Nitrogen oxides (NO_x) emissions will be controlled by Dry Low NO_x combustors. This technology combined with the use of an SCR while operating in combined cycle mode will ensure that facility-wide annual emissions of NO_X are less than or equal to 453 TPY. Emissions of carbon monoxide (CO) will be controlled to 17 ppm, while emissions of volatile organic compounds (VOC) will be less than 4.6 ppm. Emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regulated air pollutants as a result of this project.

Pollutants	Maximum Facility Emissions
PM/PM_{10}	452.8/408.5
SAM	26.6
SO_2	145.1
NO_x	453.2
VOC	140.6
CO	1839.8

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. The project is over 200 km from any PSD Class I Area. The amount of PSD Class II increment consumed by this project along with all other increment-consuming sources in the area is shown below:

PSD Class II Increment (PM_{10})	Increment Consumed ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed
24-hour	26	30	87
Annual	4	17	24

The Department will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue PSD Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

Florida Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Florida Department of Environmental Protection
Central District Office
3319 Maguire Blvd., Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and Permit may be viewed at www.dep.state.fl.us/air by clicking on *Permitting* and then *Utilities* and *Other Facilities.*

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Calpine Construction & Finance Company, LP

Blue Heron Energy Center
1080 Megawatt Combined Cycle Facility

Indian River County

PSD-FL-309, PA00-42

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

January 31, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Calpine Construction Finance Company, LP
The Pilot House, 2nd floor, Lewis Wharf
Boston, MA 02110

Authorized Representative: Mr. Robert K. Alff, Senior Vice President

1.2 Reviewing and Process Schedule

12-05-00: Date of Receipt of Application
01-31-01: Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The Blue Heron Energy Center (BHEC) is to be located at SW 74th Avenue, approximately 5 miles southwest of Vero Beach, Florida. The nearest PSD Class I area (Everglades National Park) is located approximately 205 kilometers south of the BHEC site. It is additionally located approximately 240 kilometers from the Chassahowitzka National Wilderness Area. The UTM coordinates of this facility are Zone 17; 551.2 km E; 3048.7 km N. See Figures 1 and 2 below.

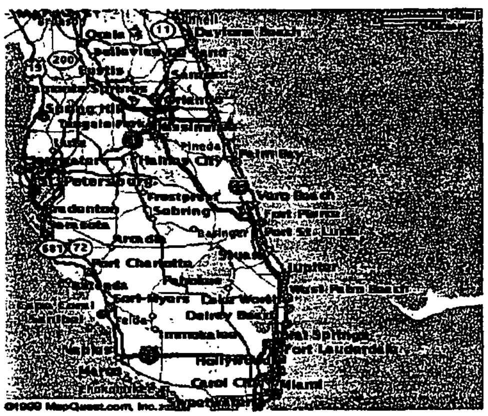

FIGURE 1

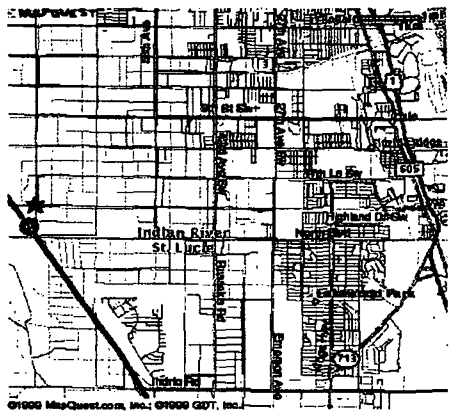

FIGURE 2

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

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

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

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
002	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
003	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
004	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
005	Water Cooling	North Main Fresh Water Cooling Tower
006	Water Cooling	South Main Fresh Water Cooling Tower
007	Water Cooling	Wastewater Cooling Tower

Calpine Construction Finance Company, LP (Calpine) proposes to construct a nominal 1080-megawatt (MW) combined cycle plant. The 50.5 acre plant site is to be located approximately 5.5 miles south-southeast of the intersection of State Road (SR) 60 and Interstate 95 (I-95). The plant site is bordered on the west by I-95, several borrow pit lakes, and undeveloped property; to the north by a single-family residence, the Indian River County Correctional Institute and a solid waste landfill; to the east by a wastewater sprayfield operated by Ocean Spray Cranberries, Inc., and by inactive citrus groves; and to the south by undeveloped lands and I-95.

The project includes: four nominal 170 MW Westinghouse 501FD combustion turbine-electrical generators configured in combined cycle mode, operating solely on natural gas; four 260 million Btu per hour (MMBtu/hr) supplementally-fired heat recovery steam generators (HRSG); two 200 MW (gross output) steam turbines; four stacks; an emergency (diesel-fired) generator; a diesel firewater pump; 2 fresh water cooling towers; one wastewater cooling tower and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2. Each combination of combustion turbine and HRSG will have a maximum heat input rating of 2,265 MMBtu/hr at a lower heat value (LHV) of 20,981 Btu/lbm while operating at maximum output and 20°F (specified as case 4 in Table C-9 of the application).

The fuel will be pipeline quality natural gas and the unit will operate up to 8760 hours per year. Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). PSD review is required for CO, SO_2, SAM, PM/PM_{10}, NO_X, and VOC since emissions, per the application, will increase by more than their respective significant emissions levels.

Calpine's application was prepared by Environmental Consulting & Technology, Inc. (ECT).

4. PROCESS DESCRIPTION

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

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the compressor of the 501 F where it is then directed to the combustor section, fuel is introduced, ignited, and burned. The combustion section consists of multiple separate can-annular combustors instead of a single combustion chamber.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 501 F operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures up to 2700 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance-of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are three basic operating cycles for gas turbines. These are simple cycle, regenerative, and combined cycles. In the Calpine project, the 501 F will operate in the combined cycle mode and as a continuous duty unit (versus an intermittent duty peaking unit).

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine, which also drives an electrical generator. Typical combined cycle efficiencies are up to 55 percent. The 501 F can achieve over 50 percent efficiency in combined cycle operation, especially if the gas turbine and the HRSG/steam generator power a common shaft connected to a single electric generator. See Figures 3 and 4 below.

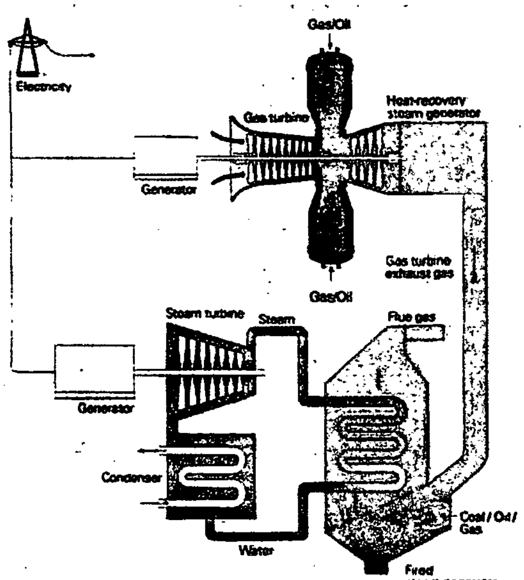

FIGURE 3

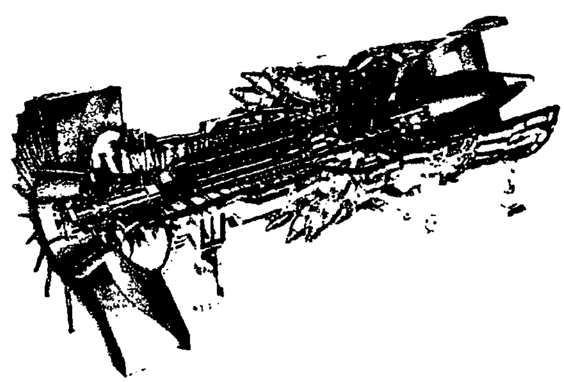

FIGURE 4

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

5. RULE APPLICABILITY

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

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

This PSD review consists of a determination of Best Available Control Technology (BACT) for SO_2, SAM, PM/PM_{10}, VOC, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth. ***This project will also be reviewed for Site Certification under the Power Plant Siting Act.***

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

5.1 State Regulations

Chapter 62-17	Electrical Power Siting
Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

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

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, sulfuric acid mist, and negligible quantities of lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 20 through 24 of Draft Permit PSD-FL-309.

6.2 Emission Summary

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

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutants	4 CT/HRSG with Duct Burners[1]	Cooling Towers	Emergency Generator and Diesel Fire Pump[2]	Total	PSD Significance	PSD REVIEW?
PM/PM_{10}	339.0/339.0	113.6/69.3	0.2/0.2	452.8/ 408.5	25	Yes
SO_2	145	0	0.1	145.1	40	Yes
NO_X	448.2	0	5.0	453.2	40	Yes
CO	1838.6	0	1.1	1839.8	100	Yes
Ozone (VOC)	140.3	0	0.2	140.6	40	Yes
Sulfuric Acid Mist	26.6	0	Neg.	26.6	7	Yes
Lead	0.5	0	Neg.	0.5	0.6	No

1. Based on 4380 hours/year at 100% output, 59 °F compressor inlet temperature, 2880 hours/year at 100% output using power augmentation, evaporative cooling and duct burners at 95°F compressor inlet temperature, and 1500 hours/year at 60% output and 59°F compressor inlet temperature.
2. Categorically exempt under Rule 62-210.300(3), F.A.C. Emissions based upon combined fuel use limits in Rule.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean natural gas along with the use of an SCR. The gas turbine combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The SCR will control emissions of NO_X to 3.5 ppm @15% O_2 between 60 and 100% of full load under normal operating conditions. Low NO_X burners will be utilized in the HRSG to achieve NO_X values of 0.1 lb/MW-hr. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Air Quality Analysis Introduction

The proposed project will increase emissions of six regulated pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, SO_2, NO_2, CO, VOC and SAM. PM_{10}, SO_2 and NO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. SAM is a non-criteria pollutant and has no AAQS or PSD increments defined for it; therefore, no air quality impact analysis was required for SAM. Instead, the BACT requirements will establish the SAM emission limit for this project. Potential emissions for VOC are above the 40 TPY significance threshold for the pollutant ozone. The applicant presented the potential increase to the Department. Based on the options available to predict potential impacts associated with the emissions and formation of ozone, the Department has determined that the use of regional models which incorporate the complex chemical mechanisms for predicting ozone formation are not feasible for this project.

The applicant's initial Class II SO_2, NO_2 and CO analyses revealed no significant impacts in the area surrounding the proposed facility; therefore, full impact Class II AAQS and PSD Class II increment analyses were not required to be conducted for SO_2, NO_2 and CO. Because the project's impact for S02, NO_2 and CO are less than the de minimus monitoring concentrations, preconstruction monitoring was not required for these pollutants.

No impacts on the Everglades National Park, the closest PSD Class I, were calculated since the project is located 205 km north of this area.

In summary, the air quality impact analyses required by the PSD regulations for this project include:

- An analysis of existing air quality for SO_2, PM_{10}, NO_2, CO and VOC;
- A significant impact analysis for SO_2, PM_{10}, NO_2 and CO;
- A PSD increment analysis for PM_{10};
- An Ambient Air Quality Standards (AAQS) analysis for PM_{10};
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. This monitoring requirement may be satisfied by using previously existing representative monitoring data, if available. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year. The table below shows maximum project air quality impacts for comparison to these de minimis levels.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMUS LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than De Minimus (Yes/No)?**	**De Minimus Level ($\mu g/m^3$)**
PM_{10}	24-hr	27	YES	10
CO	8-hr	171	NO	575
NO_2	Annual	1	NO	14
SO_2	24-hour	5	NO	13
VOC	Annual Emission Rate	141 TPY	YES	100 TPY

As shown in the table NO_2, SO_2 and CO emissions are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. However, PM_{10} and VOC impacts from the project are predicted to be greater than the de minimis levels; therefore, the applicant is not exempt from preconstruction monitoring for these pollutants. The applicant may instead satisfy the preconstruction monitoring requirement using previously existing representative data. Previously existing representative monitoring data do exist from PM_{10} and ozone monitors in the local Fort Pierce area. These data are appropriate for fulfilling the monitoring requirement for these pollutants, and to establish background concentrations for use in the PM_{10} AAQS analysis. The background concentrations for PM_{10} are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	**Averaging Time**	**Background Concentration ($\mu g/m^3$)**
PM_{10}	Annual	20
	24-hour	39

6.4.3 Models and Meteorological Data Used in the Air Quality Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Because five years of data are used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted annual average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

6.4.4 Significant Impact Analysis

Significant impact modeling is performed using the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. In order to determine the worst-case emission scenarios, the ISCST3 model in screening mode was used to assess each of the 22 CTG/HRSG operating cases (i.e., a matrix of three CTG loads [100-, 70-, and 60-percent]; four ambient temperatures [20, 59, 72 and 95°F]; and three operating modes [CTG inlet air evaporative cooling, CTG steam power augmentation, HRSG duct burning firing] for each pollutant. The worst case operating modes identified by the ISCST3 screening mode for each pollutant were then used as input for the significant impact modeling. This modeling uses ISCST3 in its regular mode. For all pollutants except PM_{10}, the 100-percent load, CTG inlet air evaporative cooling, CTG steam power augmentation, and HRSG duct burner firing mode was the worst case emission scenario. Maximum PM_{10} impacts were predicted to occur under the 100 percent load, CTG inlet air evaporative cooling and HRSG duct burner firing case. Nearly 1500 receptors were placed along the facility's restricted property line and out to 10 km from the facility, which is located in a PSD Class II area. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts were predicted in the vicinity of the facility. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact? (Yes/No)	Radius of Significant Impact (km)
PM_{10}	Annual	3	1	YES	3
	24-hr	27	5	YES	3
SO_2	Annual	0.31	1	NO	---
	24-hour	4.8	5	NO	---
	3-hour	16	25	NO	---
CO	8-hr	171	500	NO	---
	1-hr	525	2,000	NO	---
NO_2	Annual	0.72	1	NO	---

As shown in the table the maximum predicted air quality impacts due to PM_{10} emissions from the proposed project are greater than the PSD significant impact levels. Therefore, the applicant was required to do full impact PM_{10} modeling within the applicable significant impact area to determine the impacts of the project along with all other sources in the vicinity of the facility.

6.4.5 PSD Increment Analysis

The PSD increment represents the amount that sources constructed after the PSD Baseline dates, (February 8, 1988 for NO_2 and January 6, 1975 for PM_{10} and SO_2), may increase ambient ground level concentrations of a pollutant. The results of the required PSD Class II increment analyses presented in the table below show that all of the maximum predicted impacts are less than the allowable Class II increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m³)**	**Impact Greater than Allowable Increment? (Yes/No)**	**Allowable Increment (μg/m³)**
PM_{10}	Annual	4	NO	17
	24-hr	26	NO	30

6.4.6 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 significantly contribute to a violation of any AAQS.

AMBIENT AIR QUALITY IMPACTS						
Pollutant	**Averaging Time**	**Major Sources Impact (μg/m³)**	**Background Concentration (μg/m³)**	**Total Impact (μg/m³)**	**Total Impact Greater than AAQS**	**Florida AAQS (μg/m³)**
PM_{10}	Annual	4	20	24	NO	50
	24-hr	33	39	72	NO	150

6.5 Additional Impacts

6.5.1 Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with a conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. Based upon the small increases in pollutant levels, no adverse effect on AQRVs is expected within the vicinity of the plant site. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

6.5.2 Impact On Visibility

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. The location is significantly remote from any Class I PSD areas, so as to have an undetectable impact on visibility and regional haze.

6.5.3 Growth-Related Air Quality Impacts

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and to assess air quality impacts that would result from that growth.

Impacts associated with the construction of BHEC and ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The BHEC is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the Project are anticipated. When operational, the project is projected to generate approximately 36 new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas demand due to operation of the BHEC project will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

6.5.4 Hazardous Air Pollutants

An analysis supplied by ECT, utilizing AP-42 emission factors (Sec. 3.1 April 2000) indicates that the project is not a major source of hazardous air pollutants (HAPs). Accordingly it is not subject to any specific industry or HAP control requirements pursuant to Sections 112 of the Clean Air Act.

7. CONCLUSION

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

Michael P. Halpin, P.E., Review Engineer

Cleve Holladay, Meteorologist

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Blue Heron Energy Center
Calpine Construction Finance Company, L.P.
PSD-FL-309 and PA00-42
Indian River County, Florida

BACKGROUND

The applicant, Calpine Construction Finance Company, L.P. (Calpine), proposes to build a 1080 MW (average ambient net megawatts) combined cycle power plant as a new facility. The location of the proposed plant is approximately 5 miles southwest of Vero Beach, in Indian River County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are four nominal 170 MW, Siemens Westinghouse "F" Class (501FD) combustion turbine-electrical generators, fired solely with pipeline natural gas and equipped with evaporative coolers on the inlet air system. The project includes four heat recovery steam generators (HRSGs), each with a 135 ft. stack and two steam turbine-electrical generator rated at approximately 200 MW each. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes three mechanical draft cooling towers, an emergency (gas-fired) generator and a diesel fire pump. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated January 31, 2001, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on December 5, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc (ECT). The proposal is summarized in the table below (MW loads are assumed to be at 70% or higher).

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 9 ppmvd Ammonia Slip
SO_2 / SAM	Pipeline Natural Gas	1.5 grains S / 100 scf
CO	Pipeline Natural Gas Good Combustion	10 ppmvd 15.6 ppmvd with Duct Burners on (DB) 25 ppmvd during power augmentation (PA) 38.5 ppmvd during DB plus PA
VOC	Pipeline Natural Gas Good Combustion	1.2 ppmvd 6.6 ppmvd during DB plus PA
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2
PM (Main cooling towers; N & S)	High efficiency drift eliminators	0.002% drift loss
PM (Wastewater cooling tower)	High efficiency drift eliminators	0.005% drift loss

Based upon the applicant's submittal, the maximum annual emissions that the facility has the potential to emit (PTE) are as follows: 145.1 TPY SO_2, 26.6 TPY SAM, 452.8/408.5 TPY PM/PM_{10}, 453.2 TPY NO_X, 1839.8 TPY CO and 140.6 TPY of VOC.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

BACT DETERMINATION PROCEDURE:

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

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

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

The duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The 0.1 lb/MW-hr NO_X emission rate proposed by Calpine is well below the revised Subpart Da output-based limit of 1.6 lb/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

The diesel-fired emergency generator and fire pump will only be operated a few hours per month (so as to ensure their reliability for emergency use) and are considered insignificant for this analysis.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The applicant's proposed BACT is included for reference.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 mmBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine Sutter	545	2.5 – (CT) 1 hour average (LAER)	DLN/SCR	Nearly identical to Osprey.
Calpine Delta	880	2.5 – (CT & DB) 1 hour average (LAER)	DLN/CSR	3 GE 7FA's or 3 WH 501FD's; 10 ppm max ammonia slip
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Nearly identical to Osprey; Replace SCR catalyst after 36 mo.
Calpine Osprey	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip design = 9 ppm
Calpine BHEC (proposed)	1080	3.5 – (CT& DB)	DLN/SCR	Ammonia slip design = 9 ppm

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
PA = Power Augmentation
WH = Westinghouse
GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine Sutter	4 – NG Oxidation Catalyst		11.5 lb/hr	Clean Fuels Good Combustion
Calpine Delta	10 – NG (CT & DB) 10 – NG (DB & PA) 3 hr avg. – No Ox. Cat.	2 - NG	0.25 gr.S/100 scf Nat. Gas	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	1.5 - NG	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	2.3 – NG (CT) 4.6 – NG (DB & PA)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
Calpine BHEC (proposed)	10 – NG (CT only) 15.6 – NG (CT & DB) 38.5 – NG (DB & PA)	1.2 – NG (CT) 6.6 – NG (DB & PA)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

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

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Letter from Air Quality Branch, Fish & Wildlife Service dated April 17, 2000
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas, its use is not planned for this project.

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

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Furthermore the duct burner size is only 260 MMBtu/hr compared with the turbine that can accommodate a heat input greater than 1700 MMBtu/hr (LHV). The duct burner will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

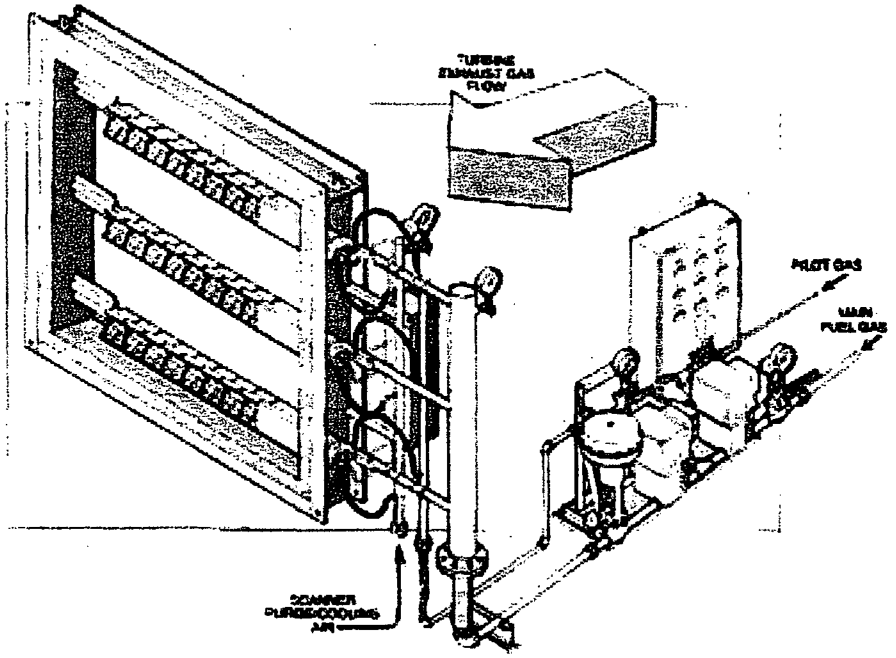

FIGURE A

Selective Catalytic Reduction

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

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR.

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

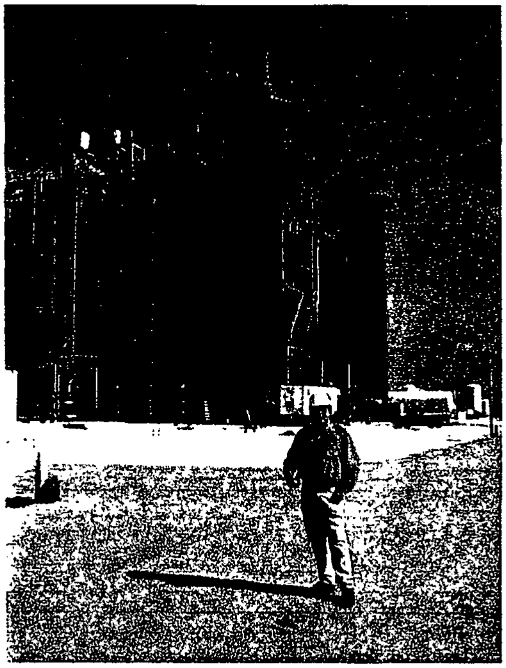

Figure B

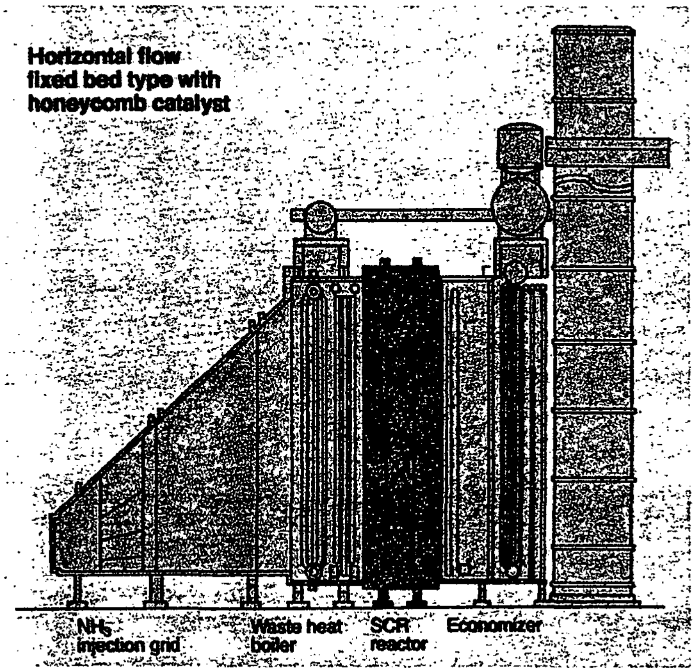

Figure C

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits as low as 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SCNR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). However, the process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads one to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™[2]. The overall project includes several more 250 MW several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E has applied for the installation of SCONOx™ on an F frame unit at Otay Mesa in Southern California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit.

XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications.

<u>REVIEW OF PARTICULATE MATTER (PM/PM_{10}) AND SO_2 CONTROL TECHNOLOGIES:</u>

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

Natural gas is an inherently clean fuel and contains no ash. Natural gas will be the only fuel fired at the Blue Heron Energy Center and is efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} or SO_2 either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} as well as SO_2 is a combination of good combustion practices, fuel quality, and filtration of inlet air.

The applicant has identified PM emissions of up to 107.9 TPY from the (main) fresh-water cooling towers, and an additional 5.7 TPY of PM emissions from the wastewater-cooling tower. Accordingly, drift eliminators shall be installed on all three cooling towers to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate for the main cooling towers and 0.005 percent for the wastewater cooling tower. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for these types of cooling towers.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

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

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. Calpine proposes to meet a limit of 10 ppmvd while firing natural gas above 70% output with the duct burner off. However, the applicant proposes higher values of 15.6, 25 and 38.5 for the operating modes of duct burner firing, power augmentation and their combination, respectively. The combined operating modes have been requested for 2880 hours per year. The applicant additionally notes that CO emissions approach 50 ppmvd at loads between 60% and 70% and requests the ability to operate up to 1500 hours per year in this reduced output range.

The Department has not reviewed an extensive body of actual data, but has reasonable assurance that the WH 501FD unit selected by Calpine will achieve values below those proposed, without requiring installation of an oxidation catalyst. However, the authorized hours of off-normal operation will be decreased from the applicant's request to 2 hours per day at 60% - 70% output as well as 2 hours per day for each of the above operating modes (on an equivalent basis). The remaining 16 equivalent hours per day will be allotted for routine (10 ppmvd CO emission rate) operation. The Department will require the use of a CEMS for compliance on a 24-hour block average, with two limits depending upon actual operation. The limits will be:

a) 10 ppmvd based upon a 24-hour block average for those days when no valid hour includes the use of duct burner firing, power augmentation or 60-70% operation; otherwise, the limit is
b) 17 ppmvd based upon a 24-hour block average {rationale: 10 ppmvd x 16/24 hours plus 15.6 ppmvd x 2/24 hours plus 25 ppmvd x 2/24 hours plus 33.4[1] ppmvd x 2/24 hours plus 50 ppmvd x 2/24 hours} [1]Note: Value lowered for consistency with Calpine's Osprey Energy Center.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Calpine for this project are 3.0 ppm with the duct burner off (between 60% and 70% output) and 6.6 ppm with the duct burner on during power augmentation. According to the applicant's submittals, VOC emissions less than 2 ppm will be achieved at 100% output and duct burners off. [5]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Calpine project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits (or their equivalents in terms of pounds per hour and NSPS units) as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 24.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion Inlet Air Filtering	10 Percent Opacity 26.0 lb/hr during DB plus PA 5 ppmvd Ammonia Slip
SO_2 / SAM	Pipeline Natural Gas	1.5 grains S / 100 scf
VOC	Pipeline Natural Gas Good Combustion	1.2 ppmvd 6.6 ppmvd during DB plus PA
CO	Pipeline Natural Gas Good Combustion	10 ppmvd – 24 hour block average, or 17 ppmvd – 24 hour block average; and 10 ppmvd and 43 lb/hr w/o DB plus PA
NO_X (all operating modes)	DLN & SCR	3.5 ppmvd (SCR) – 3 hour block average DB limited to 0.1 lb/MW-hr 31.9 lb/hr during DB plus PA 5 ppm ammonia slip
PM (Main cooling towers; N & S)	High efficiency drift eliminators	0.002% drift loss
PM (Wastewater cooling tower)	High efficiency drift eliminators	0.005% drift loss

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[6] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[9]
- EPA advised FDEP that it intended to appeal the KUA Permit if the Department did not require a NO_X emissions rate of 3.5 ppmvd when firing natural gas.[7]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5 ppmvd ammonia slip rate to be BACT, as recently determined by CPV Gulf Coast (PSD-FL-300).
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[8]
- VOC emissions of <2 ppm from the combustion turbine by Good Combustion proposed by the applicant are acceptable values determined as BACT. However even lower values have already been achieved by the previous generation DLN 2 combustors on the GE's 7FA units after tuning. Similar VOC performance is expected with the Westinghouse combustors while firing natural gas.

- The CO concentrations of 10 ppmvd are low, for operation with the duct burner off. This emission rate will be verified on an annual basis via stack test. With the duct burner on, emissions will be less than 20 ppmvd, which is within the range of recent Department BACT determinations for combustion turbines alone. However, values as high as 50 ppmvd for 60% - 70% operation will not be authorized for up to 1500 hours annually, as requested by the applicant. The CO limit will be 10 ppmvd on a 24-hour block average, or 17 ppmvd on a weighted daily (24-hour block) average, which incorporates a reasonable allowance for all daily off-normal operations. CEMS will be used for compliance.
- For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppmvd on gas while the limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E
Ammonia Slip	CTM-027 initial and annual (The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X or CO standard. These excess emissions periods shall be reported as required in Specific Condition 27 of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C. and applicant request].

Excess emissions may occur under the following startup scenarios:

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

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Cleve Holladay, Meteorologist, New Source Review Section

Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

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

REFERENCES

1 News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

2 "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

3 Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

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

5 Application for Air Permit, Emissions Unit Pollutant Detail Information, Page 9 of 11. Calpine Blue Heron Energy Center application received 12-5-2000.

6 Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.

7 Letter. Smith, Winston, EPA Region IV, to Rhodes, H.L., FDEP. Proposed KUA Permit. November 8, 1999.

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

9 Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

PERMITTEE:

Calpine Construction Finance Company, LP (Calpine)
The Pilot House, 2nd floor, Lewis Wharf
Boston, MA 02110

File No.	PSD-FL-309 (PA00-42)
FID No.	0610082
SIC No.	4911
Expires:	December 31, 2003

Authorized Representative:

Mr. Robert K. Alff, Senior Vice President

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 1080 megawatt (MW) Combined Cycle plant consisting of: four nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; four supplementally-fired heat recovery steam generators (HRSGs); two nominal 200 MW steam electrical generators; four stacks; an emergency (diesel-fired) generator; a diesel fire pump; three cooling towers; four selective catalytic reduction units including ancillary equipment and ammonia storage. The combined cycle plant will achieve approximately 1332 megawatts in combined cycle operation during extreme winter peaking conditions. The facility is designated as Blue Heron Energy Center and will be situated approximately 5 miles southwest of Vero Beach, Indian River County. UTM coordinates are: Zone 17; 551.2 km E; 3048.7 km N.

STATEMENT OF BASIS:

This PSD 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 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendix is made a part of this permit:

Appendix GC — Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The proposed Blue Heron Energy center is a nominal 1080 MW combined cycle plant. It will include: four nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; four supplementally-fired heat recovery steam generators (HRSGs); two nominal 200 MW steam electrical generators; four stacks; an emergency (diesel-fired) generator; a diesel fire pump; three cooling towers; four selective catalytic reduction units including ancillary equipment and ammonia storage. New major support facilities include wastewater facilities and a transmission line.

Emissions from Blue Heron Energy Center will be controlled by Dry Low NO_X (DLN) combustors and selective catalytic reduction (SCR). Pipeline quality natural gas and good combustion practices will be employed to control all pollutants.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSIONS UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
002	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
003	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
004	Power Generation	One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator
005	Water Cooling	North Main Fresh Water Cooling Tower
006	Water Cooling	South Main Fresh Water Cooling Tower
007	Water Cooling	Wastewater Cooling Tower
xxx	Miscellaneous	Emergency Generator and Diesel Fire Pump

REGULATORY CLASSIFICATION

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

SECTION I - FACILITY INFORMATION

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

This project has been submitted as if it is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

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

PERMIT SCHEDULE

- xx/xx/01 PSD Permit Issued
- xx/xx/01 Site Certification Issued
- xx/xx/01 Notice of Intent to Issue PSD Permit published in xxxxxxxxxxxxx
- 02/06/01 Distributed Intent to Issue Permit
- 12/05/00 Received PSD Application

RELEVANT DOCUMENTS:

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

- Application received on December 5, 2000.
- Department's Intent to Issue and Public Notice Package dated February 6, 2001.
- Department's Draft Permit and Draft BACT determination dated January 31, 2001.
- Letters from EPA Region IV dated xx/xx/01.
- Letter from Fish & Wildlife Service dated xx/xx/01.
- Site Certification for the Blue Heron Energy Center dated xx/xx/01.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II - ADMINISTRATIVE REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2003 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]

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

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

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

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

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS

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

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emissions Units 001 through 004. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 260 MMBTU/hr duct burner (LHV) and combined with two each 200 MW steam electrical generators. These shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

5. ARMS Emission Units 005 through 007. Cooling Towers, are unregulated emission units. The Cooling Towers are not subject to a NESHAP because chromium-based chemical treatment is not used.

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of the fuel to this Unit at ISO conditions shall not exceed 1,760 million Btu per hour (mmBtu/hr) when firing natural gas without power augmentation. This maximum heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be

provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 260 MMBtu/hour (LHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. 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.

11. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

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

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

14. Maximum allowable hours of operation for the 1080 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is not permitted. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

15. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustors shall be installed on each stationary combustion turbine and the permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 20. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 24. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

18. Drift eliminators shall be installed on the cooling towers to reduce PM/PM_{10} emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002 gallons/100 gallons recirculation water flowrate for the main towers and 0.005 gallons/100 gallons for the wastewater cooling tower.

EMISSION LIMITS AND STANDARDS

20. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on or off, shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO_X shall not exceed 31.9 lb/hr (at 18°F ambient temperature) while operating in the power augmentation mode with the duct burner on, to be demonstrated by annual stack test. [BACT Determination]
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 29 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall exceed neither 10 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS for those days when no valid hour includes the use of duct burner firing, power augmentation or 60-70% operation (otherwise, the limit is 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS); and neither 10 ppmvd @15% O_2 nor 43 lb/hr per unit at 100% output with the duct burner off and no power augmentation to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. [BACT, Rule 62-212.400, F.A.C.]

22. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 1.2 ppmvd @15% O_2 per unit with the duct burner off and neither 6.6 ppmvd @15% O_2 per unit with the duct burner on and operating in the power augmentation mode to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot). Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 42 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-001 through EU-004 at 36.3 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

24. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. PM/PM_{10} emissions from each combustion turbine and HRSG train shall not exceed 26.0 lb/hr at 100% output with the duct burner on and operating in the power augmentation mode to be demonstrated by initial stack test using EPA Method 5. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to and shutdowns from combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. Operation below 60% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700, F.A.C.].

26. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

27. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office 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. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 40 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 through 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 28. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or change of combustors, if specifically requested by the DEP on a case-by-case basis. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA reference Method 5, "Determination of Particulate Emissions from Stationary Sources." Initial test only.

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement); Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- Method CTM-027 for ammonia slip (I,A).

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

30. <u>Continuous compliance with the CO and NO_X emission limits</u>: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 40 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 27. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

31. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

32. <u>Compliance with CO emission limit</u>: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75.

33. <u>Compliance with the VOC emission limit</u>: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required.

34. <u>Testing procedures</u>: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient

temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

35. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.

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

37. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

39. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

40. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NOx shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry

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

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24 hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur. Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

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

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

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

42. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to the sole use of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)) for the CT's.
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

43. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.

- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

44. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 20. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.
- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.
- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.
- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.
- Ammonia emissions shall be calculated continuously using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

  Ammonia slip @ 15%O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:
  A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)
  B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)
  C = change in measured NO_X (ppmv@15%O_2) across catalyst
  D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

  The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.
- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

7099 3400 0000 1449 3973

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

Article Sent To:
Kevin Doty

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

Calpine

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Kevin S Doty
Street, Apt. No.; or PO Box No.
1701 A1A Ste 220
City, State, ZIP+4
Vero Beach Fl 32963-2206

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Kevin S. Doty
Pelican Island Audobon Society
Hatch & Doty PA
1701 A1A Suite 220
Vero Beach, FL 32963-2206

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery 2/9/01

C. Signature
[signature] ☒ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)
7099 3400 0000 1449 3973

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

UNITED STATES POSTAL SERVICE

ORLANDO FL 328 PM 09 FEB 2001

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED
FEB 12 2001
BUREAU OF AIR REGULATION

32399+6542

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

7099 3400 0000 1449 2808

Article Sent To:
Mr. Robert K. Alff

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

Calpine

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Robert K. Alff
Street, Apt. No.; or PO Box No.
The Pilot House, 2nd Fl - Lewis Wharf
City, State, ZIP+4
Boston, MA 02110

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Robert K. Alff, Sr. V.P.
Calpine Construction and
Finance Company, L.P.
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 2/12/01

C. Signature
X
☐ Agent
☒ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 2808

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

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED
FEB 19 2001
BUREAU OF AIR REGULATION

7099 3400 0000 1453 2412

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

Article Sent To:

Mr. Charles Lee, Jr., Srl VP

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

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Florida Audubon Society
Street, Apt. No.; or PO Box No.
1331 Palmetto Ave., Suite 110
City, State, ZIP+4
Winter Park, FL 32789

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Charles Lee, Jr. Sr. VP
Florida Audubon Society
1331 Palmetto Ave., Suite 110
Winter Park, FL 32789

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) Lynda White
B. Date of Delivery 2-09-01
C. Signature
X Lynda T White
☐ Agent ☒ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)
7099 3400 0000 1453 2412

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

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

FLORIDA PDC FL
9 FEB
2001

• Sender: Please print your name, address, and ZIP+4 in this box •

RECEIVED
FEB 13 2001
BUREAU OF AIR REGULATION

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

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

Article Sent To:
Ms. Caroline Ginn

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

Postmark Here

7099 3400 0000 1453 2443

Name (Please Print Clearly) (to be completed by mailer)
Indian River Board of County Comm.
Street, Apt. No.; or PO Box No.
1840 25 St.
City, State, ZIP+4
Vero Beach, FL 32960

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Caroline Ginn, Chairman
Indian River Board of County
Commissioners
1840 25 Street.
Vero Beach, FL 32960

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) K. STRICKLAND B. Date of Delivery 2/9/01

C. Signature
X K. Strickland ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label) 7099 3400 0000 1453 2443

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

UNITED STATES POSTAL SERVICE

PM
09 FEB
2001

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED
FEB 12 2001
BUREAU OF AIR REGULATION

32399+6542