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STATE OF FLORIDA
SITING BOARD

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DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: CALPINE CONSTRUCTION FINANCE COMPANY, L.P. (OSPREY ENERGY CENTER) POWER PLANT SITING APPLICATION NO. PA00-41

OGC CASE NO. 00-0740
DOAH CASE NO. 00-1288EPP

JL JT

FINAL ORDER APPROVING CERTIFICATION

On May 23, 2001, an administrative law judge with the Division of Administrative Hearings ("DOAH") submitted his Recommended Order in this certification proceeding. The Recommended Order indicates that copies were served upon counsel for Calpine Construction Finance Company, L.P ("Calpine"), the Department of Environmental Protection ("DEP"), and other designated state agencies. A copy of the Recommended Order is attached as Exhibit A. The matter is now before the Governor and Cabinet, sitting as the "Siting Board," for final agency action under the Florida Electrical Power Plant Siting Act ("PPSA") embodied in §§ 403.501-403.518, Florida Statutes.

BACKGROUND

On March 20, 2000, Calpine filed an application with DEP to construct and operate a nominal 527 megawatt natural gas-fired, combined cycle electrical power plant, known as the "Osprey Energy Center" or the "Osprey Project." The proposed site of the Osprey Project is located entirely within the municipal limits of the City of Auburndale, Florida, in north-central Polk County. The proposed site, approximately 19.5 acres in size, is located about 1.5 miles from downtown Auburndale. DEP forwarded the matter to DOAH for formal administrative proceedings and Administrative Law Judge, J. Lawrence Johnston (the "ALJ"), was assigned to preside over the case.

A land use hearing was held by the ALJ in this case pursuant to § 403.508(1) of the PPSA. On February 28, 2001, the ALJ entered a Land Use Recommended Order recommending that the Siting Board enter an order finding that the Osprey Project site is consistent and in compliance with existing land use plans and zoning ordinances. The Siting Board subsequently entered a Land Use Order determining that the site of the Osprey Energy Center is consistent and in compliance with existing land use plans and zoning ordinances.

On April 17, 2001, a certification hearing was conducted by the ALJ in compliance with § 403.508(3) of the PPSA. At the certification hearing, expert testimony and documentary evidence was presented in favor of the Osprey Project by Calpine and by DEP. In addition, representatives of the Central Florida Development Council and the City of Auburndale offered comments in favor of the Osprey Project. No one contested the evidence presented by Calpine and DEP, and none of the other parties to this proceeding called any witnesses or proffered any exhibits at the certification hearing. Although the general public was given an opportunity to comment at the certification hearing, no one from the public testified or proffered any exhibits in opposition to the Osprey Project.

RECOMMMENDED ORDER

The Recommended Order now on review before the Siting Board includes the following significant findings and conclusions of the ALJ:

1. The electricity generated at the Osprey Energy Center will be produced by natural gas, which is the cleanest burning fossil fuel available to generate electricity.

2. Calpine has provided reasonable assurances that the Osprey Project will comply with all applicable air quality standards and requirements and the Conditions of Certification dealing with air quality issues.

3. The Osprey Project will not discharge any industrial or domestic wastewater to any surface water or groundwater. All of the wastewater from the Project's power plant will be discharged to the City of Auburndale's wastewater treatment facilities.

4. Calpine has provided reasonable assurance that the Osprey Project will comply with all applicable nonprocedural land use and environmental statutes, rules, policies, and regulations including, but not limited to, those requirements governing the Project's impacts on air, water consumption, the management and treatment of stormwater, and wetlands.

5. The location, construction, and operation of the Osprey Project will have minimal adverse effects on human health, the environment, the ecology of the State's lands and wildlife, and the ecology of the State's waters and aquatic life.

6. The Conditions of Certification establish operational safeguards for the Osprey Project that are technically sufficient for the protection of the public health and welfare.

The ALJ ultimately recommended that the Siting Board enter a final order granting certification for the construction and operation of the Osprey Energy Center in accordance with the revised Conditions of Certification.

CONCLUSION

No Exceptions were filed in this case by any party challenging any of the ALJ's factual findings, legal conclusions, or recommendation. Furthermore, the record is devoid of any objection to site certification of the Osprey Project by any state, regional, or local agency. The Central Florida Regional Planning Council, City of Auburndale, DEP, Department of Community Affairs, Department of Transportation, Florida Fish and Wildlife Conservation Commission, and the Southwest Florida Water Management District all recommended certification of the Project, subject to the Conditions of Certification. Polk County took no position on certification of the Osprey Project because the entire Project site is located within the municipal limits of the City of Auburndale.

Based on a review of the record in this proceeding, the Siting Board concludes that site certification of the Osprey Energy Center serves and protects the broad interests of the public and should be approved.

Having reviewed the Recommended Order and other matters of record, and being otherwise duly advised, it is ORDERED that:

A. The ALJ's Recommended Order is adopted in its entirety and is incorporated herein by reference.

B. Certification of the location, construction, and continued operation of the Osprey Energy Center as proposed in Calpine's site certification application, is APPROVED, subject to the revised Conditions of Certification effective April 17, 2001, admitted into evidence at the certification hearing as DEP Exhibit 2.

C. Authority to assure and enforce compliance by Calpine and its agents with all of the revised Conditions of Certification imposed by this Final Order is hereby delegated to DEP, except that any proposed modification to burn a fuel other than natural gas shall by reviewed by the Siting Board.

Any party to this certification proceeding has the right to seek judicial review of this Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000; and by filing a copy of the Notice of

Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Final Order is filed with the Clerk of the Department.

DONE AND ORDERED this 27th day of JUNE, 2001, in Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting held on JUNE 26, 2001.

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

THE HONORABLE JEB BUSH
GOVERNOR

FILING IS ACKNOWLEDGED ON THIS DATE, PURSUANT TO § 120.52 FLORIDA STATUTES, WITH THE DESIGNATED DEPARTMENT CLERK, RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED

CLERK

6/27/01
DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Final Order Approving Certification has been sent by United States Postal Service to:

David S. Dee, Esquire
Landers & Parsons
310 West College Avenue
Tallahasee, FL 32301

James V. Antista, Esquire
Fish and Wildlife Conservation Commission
Bryant Building
620 South Meridian Street
Tallahassee, FL 32399-1600

Sheuching Yu, Esquire
Department of Transportation
Haydon Burns Building, MS 58
605 Suwannee Street
Tallahassee, FL 32399-0458

Ann Cole, Clerk and
J. Lawrence Johnston, Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

Robert V. Elias, Esquire
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Cari L. Roth, Esquire
Department of Community Affairs
2555 Shumard Oak Boulevard
Suite 315
Tallahassee, FL 32399-2100

and by hand delivery to:

Hamilton Oven, Administrator
Department of Environmental Protection
Office of Siting Coordination
2600 Blair Stone Road
Mail Station 48
Tallahassee, FL 32399-2400

and

Scott A. Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000

this 27 day of June, 2001.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

J. TERRELL WILLIAMS
Assistant General Counsel

3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/488-9314

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

RE:

Calpine Construction Finance Company, L.P.

OSPREY ENERGY CENTER

CONDITIONS OF CERTIFICATION • PA 00-41

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I. CERTIFICATION CONTROL

Under the control of these Conditions of Certification the Calpine Construction Finance Company, L.P. will operate a nominal 540 MW facility (527 MW under average annual ambient conditions) consisting of two combustion turbine generators (170 MW each), two heat recovery steam generators, one steam turbine electric generator (200 MW), and ancillary equipment. The facility is known as the Osprey Energy Center and is located on a 19.5 acre site which is adjacent to the Auburndale Power Partners electrical power generation facility at 1501 Derby Avenue, Auburndale, Polk County, Florida. UTM coordinates are: Zone 17; 421.0 km East; 3103.2 km North.

The general and specific conditions contained in these Conditions of Certification shall apply to the construction and operation of the Osprey Energy Center.

A. Definitions

The meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, 372, and 253, Florida Statutes (F.S.), and any regulation adopted pursuant thereto and the statutes and regulations of any agency that is a party to the certification proceedings. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the Department. As used herein:

1. "Application" shall mean the Site Certification Application (SCA) for Calpine Construction Finance Company, L.P.'s Osprey Energy Center electrical power generation facility, filed with the Department on March 20, 2000, as supplemented or subsequently amended.

2. "DEP" or "Department" shall mean the Florida Department of Environmental Protection.

3. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity.

4. "Facility" shall mean Calpine Construction Finance Company, L.P.'s Osprey Energy Center, which includes the electrical power generation plant and all associated structures, including but not limited to: the combustion turbine generators, the heat recovery steam generators, duct burners, the steam turbine generator, selective catalytic reduction units, transformers, fuel and water storage tanks, natural gas delivery, air and water pollution control equipment, storm water control facilities, the cooling towers and related structures.

5. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

6. "NPDES permit" shall mean the federal *National Pollutant Discharge Elimination System* permit issued in accordance with the federal *Clean Water Act.*

7. "Permittee" shall mean the Calpine Construction Finance Company, L.P. or their successors and or assigns.

8. "Power plant" shall mean the Osprey Energy Center electrical power generating plant and appurtenances to be operated on the Calpine Construction Finance Company, L.P. site in Auburndale, Polk County, Florida, as generally depicted in the Application.

9. "Project" or "Osprey Energy Center" shall mean Calpine Construction Finance Company, L.P.'s Osprey Energy Center electrical power plant and all associated facilities.

10. "PSD permit" shall mean the federal *Prevention of Significant Deterioration* air emissions permit issued in accordance with the federal *Clean Air Act.*

11. "SWFWMD" shall mean the Southwest Florida Water Management District.

12. "Title V permit" shall mean the federal permit issued in accordance with *Title V* of the federal *Clean Air Act.*

B. Applicable Rules

The construction and operation of the Osprey Energy Center Facility shall be in accordance with all applicable provisions of at least the following regulations: Chapters 40D-2, 40D-8, 40D-21, 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, 62-762, 62-767, 62-769, 62-770, and 62-25, Florida Administrative Code (F.A.C.), or their successors as they are renumbered.

II. CHANGE IN DISCHARGE

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any regulated pollutant not identified in the application, or more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any anticipated facility expansions beyond the certified initial generating capacities of the existing unit, production increases, or process modifications which may result in new, different, or increased discharges of pollutants, or expansion in steam generation capacity shall be reported by submission of an application for amendment or modification pursuant to Chapter 403, F.S.

III. GENERAL CONDITIONS

A. Facilities Operation

1. The Permittee shall properly operate and maintain the Facility and systems of treatment and control (and related appurtenances) that are installed and used to achieve compliance with the conditions of this certification, and are 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 approval and when required by Department rules.

2. In the event of a prolonged [thirty (30) days or more] equipment malfunction or shutdown of air pollution control equipment, operation may be allowed to resume and continue to take place provided that such operation will be in compliance with all applicable ambient air quality standards and PSD increments, solid waste rules, domestic wastewater rules and industrial wastewater rules. During such malfunction or shutdown, the operation of the facility shall comply with all other requirements of this certification and all applicable state and federal emission and effluent standards not affected by the malfunction or shutdown which is the subject of the Department's order.

B. Non-Compliance Notification

If, for any reason, the Permittee does not comply with or will be unable to comply with any limitation specified in this certification, the Permittee shall notify the DEP Southwest District office by telephone at (813) 744-6100 within one business day. After normal business hours, report any condition that poses a public health threat to the State Warning Point under telephone number (850) 413-9911 or (850) 413-9912. The Permittee shall confirm this non-compliance in writing at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 within seventy-two (72) hours of becoming aware of such conditions, and shall supply the following information:

1. A description of the discharge and cause of noncompliance; and,

2. The period of non-compliance, including exact 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-complying event.

3. The Permittee shall report all critical (having potential to significantly pollute surface or ground waters) spills of liquid or liquid-solid materials, not confined to a building or similar containment structure, to the Department by telephone immediately after discovery and submit a written report within forty-eight hours, excluding weekends, from the original notification. The telephonic report shall be submitted by calling the DEP Southwest District Industrial Wastewater Compliance / Enforcement Section under telephone number (813) 744-6100. After normal business hours, contact the State Warning Point by calling (850) 413-9911 or (850) 413-9912. The written report shall include, but not be limited to, a detailed description of how the spill occurred, the name and chemical make-up (include any MSDS sheets) of the substance, the

amount spilled, the time and date of the spill, the name and title of the person who first reported the spill, the size and extent of the spill and surface types (impervious, ground, water bodies, etc.) it impacted, the cleanup procedures used and status of completion, and include a map or aerial photograph showing the extent and paths of the material flow. Any deviation from this requirement must receive prior approval from the Department.

C. Safety

1. The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards will be complied with during construction. The applicable Safety Standards specified under Section 442.20, F. S. shall also be complied with.

2. The Permittee shall not discharge to surface waters wastes which are acutely toxic, or present in concentrations which are carcinogenic, mutagenic, or teratogenic to human beings or to significant locally occurring wildlife or aquatic species. The Permittee shall not discharge to ground waters wastes in concentrations which, alone or in combination with other substances, or components of discharges (whether thermal or non-thermal) are carcinogenic, mutagenic, teratogenic, or toxic to human beings (unless specific criteria are established for such components in Section 62-520.420, F.A.C.) or are acutely toxic to indigenous species of significance to the aquatic community within surface waters affected by the ground water at the point of contact with surface waters.

D. Enforcement

The Department may take any and all lawful action as it deems appropriate to enforce any condition of this certification.

E. Design and Performance Criteria

The power plant may be operated at up to the maximum electrical output projected from design information and system capability without the need for modifying these conditions. Treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this certification are not to be bypassed without prior DEP approval.

F. Certification - General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in these conditions of certification are the same as "Permit Conditions" and are binding and enforceable pursuant to Sections 403.141, 403.161, 403.514, 403.727, and 403.859 through 403.861, F.S. Any noncompliance with a condition of certification or condition of a federally delegated or approved permit constitutes a violation of chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation, or permit revision. The Permittee is placed on notice that the Department will review this approval periodically and may initiate enforcement action for any violation of these conditions.

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

3. As provided in Subsections 403.087(7), 403.511, and 403.722(5), F.S., the issuance of this approval does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This approval is not a waiver of any other Department approval that may be required for other aspects of the total project under federally delegated programs.

4. This certification 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 approved 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. The Permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of these Conditions which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with these Conditions.

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

6. This certification is transferable only upon Department approval in accordance with Section 403.516, F.S., Rules 62-17.211(3) and 62-730.300, F.A.C., as applicable. The Permittee shall be liable for any noncompliance of the approved activity until the transfer is approved by the Department.

7. These conditions of certification or a copy thereof shall be kept at the work site of the approved activity.

8. 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 approval records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by this approval, copies of all reports required by this approval, and records of all data used to complete the application for this approval. These materials shall be retained at least three (3) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule. Data utilized to prepare the site certification application is to be maintained at the following locations:

Calpine Construction Finance Company, L.P.
The Pilot House, 2nd Floor, Lewis Wharf
Boston, Massachusetts 02110

and

Osprey Energy Center
1501 Derby Avenue
Auburndale, Florida

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.

9. These Conditions may be modified, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

10. The Permittee, by accepting these Conditions, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to

a. Enter upon the Permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under these Conditions;

b. Have access to and copy any records that shall be kept as required by these Conditions;

c. Inspect the facilities, equipment, practices, or operations regulated or required under these Conditions; and

d. Sample or monitor any substances or parameters at any location necessary to assure compliance with these Conditions or Department rules.

11. When requested by the Department, the Permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating these Conditions, or to determine compliance with the permit. The Permittee shall also provide to the Department upon request copies of records required by these Conditions to be kept. If the Permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department.

12. Unless specifically stated otherwise in Department rules, the Permittee, in accepting these Conditions, 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 rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard.

13. The Permittee, in accepting these Conditions, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C.

14. The Permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment.

15. The Permittee shall apply for a revision to any Department issued PSD, Title V, or NPDES permit in accordance with Department Rules in Chapter 62, Florida Administrative Code, before construction of any planned substantial modifications to the permitted facility is to commence or with applicable rules for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in the applicable portions of Chapter 62, F.A.C.

16. The Permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The Permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of these Conditions. The notice shall include the following information:

a. A description of the anticipated noncompliance;

b. The period of the anticipated noncompliance, including dates and times;

c. Steps being taken to prevent future occurrence of the noncompliance.

17. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in these Conditions shall be submitted no later than 14 days following each schedule date.

18. Laboratories and Quality Assurance

1. The Permittee shall ensure that all laboratory analytical data submitted to the Department, as required by this Certification, must be from a laboratory which has a currently valid and Department approved Comprehensive Quality Assurance Plan (CompQAP) [or a CompQAP pending approval] for all parameters being reported, as required by Chapter 62-160, F.A.C.

2. When a contract laboratory is used to analyze samples required pursuant to this certification, the Permittee is required to have the samples taken by appropriately trained personnel following EPA and Department approved sampling procedures and chain-of-custody requirements in accordance with Rule 62-160, F.A.C.

3. When an in-house laboratory is used to analyze samples required pursuant to this permit, the Permittee is required to have the samples taken by an appropriately trained technician following EPA and Department approved sampling procedures and chain-of-custody requirements. All chain-of-custody records must be retained on-site for at least three (3) years and made available to the Department immediately upon request.

19. Procedures for Post-Certification Submittals

a. Purpose of Submittals: Conditions of certification which provide for the post-certification submittal of information to DEP by the Permittee are for the purpose of facilitating DEP's monitoring of the effects arising from the plant facilities. This monitoring is for DEP to assure, in consultation with other agencies with applicable regulatory jurisdiction, continued compliance with the conditions of certification, without any further agency action.

b. Filings: All post-certification submittals of information by the Permittee are to be filed with DEP. Copies of each submittal shall be simultaneously submitted to any other agency indicated in the specific conditions requiring the post-certification submittals.

c. Completeness: The DEP shall promptly review each post-certification submittal for completeness. This review shall include consultation with the other agencies receiving the post-certification submittal. For the purposes of this condition, completeness shall mean that the information submitted is both complete and sufficient. If found to be incomplete,

the Permittee shall be so notified. Failure to issue such a notice within forty-five (45) days after filing of the submittal shall constitute a finding of completeness.

d. Interagency Meetings: Within sixty (60) days of the filing of a complete post-certification submittal, DEP may conduct an interagency meeting with other agencies which received copies of the submittal. The purpose of such an interagency meeting shall be for the agencies with regulatory jurisdiction over the matters addressed in the post-certification submittal to discuss whether reasonable assurance of compliance with the conditions of certification has been provided. Failure of any agency to attend an interagency meeting shall not be grounds for DEP to withhold a determination of compliance with these conditions nor to delay the time frames for review established by these conditions.

e. Reasonable Assurance of Compliance: Within ninety (90) days of the filing of a complete post-certification submittal, or forty-five (45) days after a submittal is made by the Permittee, or unless another date is specified herein, DEP shall give written notification to the Permittee and the agencies to which the post-certification information was submitted of its determination whether there is reasonable assurance of compliance with the conditions of certification. If it is determined that reasonable assurance has not been provided, the Permittee shall be notified with particularity and possible corrective measures suggested. Failure to notify the Permittee in writing within ninety (90) days of receipt of a complete post-certification submittal shall constitute a compliance determination.

IV. ADVERSE IMPACT

The Permittee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including such accelerated or additional monitoring as necessary to determine the nature and impact of the non-complying discharge.

V. RIGHT OF ENTRY

The Permittee shall allow during normal business hours the Secretary of the Florida Department of Environmental Protection and/or authorized representatives, including representatives of the SWFWMD upon the presentation of credentials:

A. To enter upon the Permittee's premises where an emission or effluent source is located or in which records are required to be kept under the terms and conditions of this certification;

B. To have access during normal business hours (Monday-Friday, 9:00 a.m. to 5:00 p.m.) to any records required to be kept under the conditions of this certification for examination and copying;

C. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants, or monitor any substances or parameters

at any location reasonably necessary to assure compliance with this certification or Department rules; and,

D. To assess any damage to the environment or violation of ambient standards.

VI. REVOCATION OR SUSPENSION

This certification may be suspended or revoked for violations of any of its conditions pursuant to Section 403.512, F.S.

VII. CIVIL AND CRIMINAL LIABILITY

A. This certification does not relieve the Permittee from civil or criminal penalties for noncompliance with any conditions of this certification, applicable rules or regulations of the Department or Chapter 403, F.S., or regulations thereunder.

B. Subject to Section 403.511, F.S., this certification shall not preclude the institution of any legal action or relieve the Permittee from any responsibilities or penalties established pursuant to any other applicable state statutes or regulations.

VIII. PROPERTY RIGHTS

A. The issuance of this certification does not convey any property rights in either real or personal property, nor any exclusive privileges, nor 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.

B. This certification 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.

IX. SEVERABILITY

The provisions of this certification are severable, and if any provision of this certification or the application of any provision of this certification to any circumstances, is held invalid, the application of such provisions to other circumstances and the remainder of the certification shall not be affected thereby.

X. REVIEW OF SITE CERTIFICATION

The certification shall be final unless revised, revoked, or suspended pursuant to law. At least every five (5) years from the date of issuance of certification the Department may review these conditions of certification and propose any needed changes.

XI. MODIFICATION OF CONDITIONS OF CERTIFICATION

A. Pursuant to Subsection 403.516(1), F.S., the Siting Board hereby delegates the authority to the Secretary of the Department to modify any condition of this certification dealing with sampling, monitoring, reporting, specification of control equipment, boiler capacity, related time schedules, emission limitations (subject to notice and opportunity for hearing), conservation easements, or any special studies conducted, as necessary to attain the objectives of Chapter 403, Florida Statutes. Approval of requests for modifications of monitoring requirements shall not be unreasonably withheld by the Department.

B. This certification shall be automatically modified to conform to any subsequent amendments, modifications, or renewals made by the Department under a federally delegated or approved program to any separately issued Prevention of Significant Deterioration (PSD) permit, Title V air permit, or National Pollutant Discharge Elimination System (NPDES) permit for the certified Facility. The Permittee shall send each party to the original certification proceedings (at the party's last known address as shown in the record of such proceeding) notice of requests for modifications or renewals of the above listed permits if the request involves a relief mechanism (e.g., mixing zone, variance, etc.) from standards, a relaxation of conditions included in the permit due to state permitting requirements, or the inclusion of less restrictive air emission limitations in the air permits. The Department shall notify all parties to the certification proceeding of any intent to modify conditions under this section prior to taking final agency action.

C. Subject to the limitations contained in Condition XI. C. and the provisions of Subsection 120.569(2)(n), F.S., the Siting Board hereby delegates the authority to the Secretary of the Department to modify any condition of this certification if the Secretary finds that an immediate danger to the public health, safety, or welfare requires the issuance of an immediate final order temporarily modifying these conditions of certification. If the Secretary elects to exercise this delegated authority, the Secretary shall prepare an immediate final order that recites with particularity the facts underlying the Secretary's finding of an immediate danger to the public health, safety or welfare. The immediate final order and the modification to these Conditions of Certification shall be effective only for so long as is necessary to address the immediate danger. A copy of the immediate final order shall be served on each member of the Siting Board and each party to the certification hearing.

D. All other modifications to these conditions shall be made in accordance with section 403.516, F.S.

XII. CONSTRUCTION

A. Standards and Review of Plans

1. All construction at the Facility shall be constructed pursuant to the design standards presented in the application or amended application and the standards or plans and drawings submitted and signed by an engineer registered in the state of Florida. Specific DEP Southwest District office acceptance of plans will be required based upon a determination of consistency with approved design concepts, regulations and these conditions prior to initiation of construction of any: industrial waste treatment facilities; domestic waste treatment facilities; potable water treatment and supply systems; ground water monitoring systems and storm water runoff systems; solid waste disposal areas; and hazardous or toxic handling facilities or areas. The Permittee shall present specific Facility plans for these facilities for review by the Southwest District office at least ninety (90) days prior to construction of those portions of the Facility for which the plans are then being submitted, unless other time limits are specified in the following conditions herein. Review and approval or disapproval shall be accomplished in accordance with Chapter 120, F.S., or these conditions of certification as applicable.

2. The Department must be notified in writing and prior written approval obtained for any material change, modification, or revision to be made to the project during construction which is in conflict with these conditions of certification. If there is any material change, modification, or revision made to a project approved by the Department without this prior written approval, the project will be considered to have been constructed without departmental approval, the construction will not be cleared for service, and the construction will be considered a violation of the conditions of certification.

3. Ninety (90) days prior to the anticipated date of first operation, the Permittee shall provide the Department with an itemized list of any changes made to the Facility design and operation plans that would affect a change in discharge as referenced in Condition II. since the time of the approval of these conditions. This pre-operational review of the final design and operation shall demonstrate continued compliance with Department rules and standards.

B. Control Measures

1. To control runoff during construction which may reach and thereby pollute waters of the state, necessary measures shall be utilized to settle, filter, treat or absorb silt containing or pollutant laden storm water to ensure against spillage or discharge of excavated material that may cause turbidity in excess of 29 nephelometric turbidity units (NTU) above background in waters of the state. Control measures may consist of sediment traps, barriers, berms, and vegetation plantings. Exposed or disturbed soil shall be protected and stabilized as soon as possible to minimize silt and sediment-laden runoff. The pH of the runoff shall be kept within the range of 6.0 to 8.5. The Permittee shall comply with the applicable nonprocedural requirements in Chapter 62-25, F.A.C.

2. Any open burning in connection with initial land clearing shall be in accordance with Chapter 62-256, F.A.C., Chapter 51-2, F.A.C., and any other applicable regulation. Any burning

of construction-generated material, after initial land clearing that is allowed to be burned in accordance with Chapter 62-256, F.A.C., shall be approved by the DEP Southwest District office in conjunction with the Division of Forestry and any other county regulations that may apply. Burning shall not occur if not approved by the appropriate agency or if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.

3. Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the appropriate local health agency.

4. Solid wastes resulting from construction shall be disposed of in accordance with the applicable regulations of Chapter 62-701, F.A.C.

5. Construction noise shall not exceed any applicable noise criteria or requirements of the City of Auburndale or Polk County. The permittee shall notify area residents in advance of the onset of the steam blowout of the Osprey Energy Center's heat recovery steam generator and steam lines. Such steam blowout shall be conducted between 7:00 am and sunset.

6. The Permittee shall employ proper odor and dust control techniques to minimize odor and fugitive dust emissions. The Permittee shall employ control techniques sufficient to prevent nuisance conditions which interfere with enjoyment of residents of adjoining property.

7. Directly associated transmission lines from the Facility electric switchyard to existing transmission lines shall be maintained in accordance with the application and the appropriate state and federal regulations concerning use of herbicides. The Permittee shall notify the Department of the type of herbicides to be used at least 60 days prior to their first use.

8. Protection of Vegetation: The Permittee shall develop the site so as to establish a buffer of natural vegetation as required by the City of Auburndale.

9. Dewatering operations during construction shall be carried out in accordance with Rule 62-621.300(2), F.A.C.

10. Historical or Archaeological Finds: If historical or archaeological artifacts, such as Indian canoes, are discovered at any time within the project site, the Permittee shall notify the DEP Southwest District office and the Bureau of Historic Preservation, Division of Historical Resources, R.A. Gray Building, Tallahassee, Florida 32399, telephone number (850) 487-2073.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a Florida registered professional engineer or other qualified person to assure that all construction activities conform to applicable environmental regulations and the applicable conditions of certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing are detected during

construction, the Permittee shall notify the DEP Southwest District office as required by Condition III.B.

D. Reporting

Notice of commencement of construction shall be submitted to the Siting Coordination Office and the Southwest District office within fifteen (15) days of initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the Southwest District office. The report shall be a short narrative describing the progress of construction.

XIII. AIR RESOURCES MANAGEMENT

A. The Permittee shall comply with all limitations, restrictions, and conditions contained in PSD permit number PSD-FL-287. The PSD permit, as attached to these Conditions of Certification, is included in and made part of these Conditions of Certification.

B. Emissions Units

Emissions Unit	System	Emissions Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
003	Steam Generation	One 250 MMBtu/hr Duct Burner configured as a Supplementary Fired Heat Recovery Steam Generator
004	Steam Generation	One 250 MMBtu/hr Duct Burner configured as a Supplementary Fired Heat Recovery Steam Generator
005	Water Cooling	Cooling Tower
xxx	Miscellaneous	Emergency Generator and Diesel Fire Pump

C. General Operations Requirements

1. Fuel

a. Only pipeline natural gas shall be fired in these units.

b. The use or storage of Orimulsion or other emulsion type fuels is specifically prohibited.

2. The maximum heat input rates, based on the lower heating value (LHV) of the fuel to this Unit at ISO conditions shall not exceed 1,669 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.

3. The maximum heat input rate of each natural gas-fired duct burner shall not exceed 250 MMBtu/hour (LHV).

4. 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.

5. 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 Southwest 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.

6. 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.

7. The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.

8. Maximum allowable hours of operation for the 527 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is not permitted.

9. The plant may not be operated without the use of the selective catalytic reduction (SCR) system except during periods of startup and shutdown.

D. Control Technology

1. Dry Low NO_X (DLN) combustors shall be installed on each stationary combustion turbine.

2. The Permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Condition XIII.E.1.

3. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification following installation (and prior to startup) shall be submitted to the Department's Division of Air Resources Management that drift eliminators were installed and that the installation is capable of meeting 0.002 gallons/100 gallons recirculation water flowrate.

E. Emissions Limits

(The procedures and frequency for determining compliance with the following emissions limits are set forth in the PSD permit no. PSD-FL-287.)

1. Nitrogen Oxides (NO_X) Emissions

a. The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating, the duct burner on or off, shall not exceed 3.5 ppmvd @15% O_2 on a 24-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 a continuous emission monitor (CEMS).

b. The emissions of NO_X shall not exceed 27.5 lb/hr (at 95°F ambient temperature) while operating in the power augmentation mode with the duct burner on, to be demonstrated by annual stack test.

c. Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu.

d. The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 9.0 ppmvd @15% O_2.

2. Carbon Monoxide (CO) Emissions

a. Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall not exceed:

(1) 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; nor

(2) otherwise exceed 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS.

b. Emissions of CO in the stack exhaust gas (at ISO conditions) with the duct burner off and no power augmentation, shall exceed neither 10 ppmvd @15% O_2 nor 45 lb/hr per unit at 100% output.

3. Volatile Organic Compounds (VOC) Emissions

a. Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall not exceed 2.3 ppmvd @15% O_2 nor 5.8 lb/hr per unit with the duct burner off.

b. Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall not exceed 4.6 ppmvd @15% O_2 nor 12.4 lb/hr per unit with the duct burner on and operating in the power augmentation mode.

4. Sulfur Dioxide (SO_2) Emissions

SO_2 emissions shall be limited by firing pipeline natural gas with a sulfur content not greater than 2 grains per 100 standard cubic feet.

5. PM/PM_{10} and Visible emissions (VE)

a. PM/PM_{10} emissions from each combustion turbine and HRSG train shall not exceed 24.1 lb/hr at 100% output with the duct burner on and operating in the power augmentation mode.

b. VE emissions shall not exceed 10 percent opacity from the stack in use.

6. Ammonia Emissions

a. 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. The following calculation represents one acceptable method by which the permittee may demonstrate compliance with this condition:

$$\text{Ammonia slip @ } 15\%O_2 = [\, A - (B \times C \times 10^{-6}) \,] \times [\, (D \times 10^{-6}) / B \,]$$

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%O2) 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.

b. The Permittee shall notify the Department's Southwest District Office within 2 business days if the calculated ammonia emissions exceed 9.0 ppmvd corrected to 15% O_2 over a 3-hour block average. The notification shall include a corrective action plan to reduce ammonia emissions below 9 ppmvd corrected to 15% O_2 over a 3-hour block average.

XIV. WATER RESOURCES MANAGEMENT

A. General Conditions (Chapters 40D-2 and 40D-3, F.A.C.)

1. If any of the statements in the application and in the supporting data are found to be materially untrue and/or inaccurate, or if the Permittee fails to comply with all of the provisions of Chapter 373, Florida Statutes (F.S.), Chapter 40D, Florida Administrative Code (F.A.C.), or the conditions set forth herein, the Southwest Florida Water Management District (SWFWMD) shall take appropriate action which may include suspension or revocation of this Site Certification.

2. This certificate is issued based on information provided by the Permittee demonstrating that the use of water is reasonable and beneficial, consistent with the public interest, and will not interfere with any existing legal use of water. If it is determined by the SWFWMD that the use is not reasonable and beneficial, in the public interest, or does impact an existing legal use of water, the SWFWMD shall initiate action which may include suspension or revocation of this Siting Certification.

3. The Permittee shall not materially deviate from the SWFWMD water use related terms or conditions of the Siting Certification without written approval by the SWFWMD.

4. In the event the SWFWMD declares that a Water Shortage exists pursuant to Chapter 40D-21, F.A.C., the SWFWMD may alter, modify, or declare inactive all or parts of this Certification as necessary to address the water shortage.

5. The SWFWMD shall collect water samples from any withdrawal point listed in the Certificate or shall require the Permittee to submit water samples when the SWFWMD determines that there is a potential for adverse impacts to water quality.

6. The Permittee shall provide access to an authorized Department or SWFWMD representative to enter the property at any reasonable time to inspect the facility and make environmental or hydrologic assessments. The Permittee shall either accompany Department and SWFWMD staff onto the property or make provision for access onto the property.

7. Issuance of this Site Certification does not exempt the Permittee from any other SWFWMD permitting requirements.

8. The SWFWMD shall initiate any necessary action to require the Permittee to cease or reduce withdrawal if water levels in aquifers fall below the minimum levels established by the SWFWMD Governing Board.

9. The Permittee shall practice water conservation to increase the efficiency of transport, application, and use, as well as to decrease waste and to minimize stormwater runoff from the property. At such time as the SWFWMD Governing Board adopts specific conservation requirements for the Permittee's water use classification, the SWFWMD shall initiate any required action to make this certification subject to those requirements upon notice and after a reasonable period for compliance.

10. The SWFWMD may establish special regulations for permits within the regions designated a Water Use Caution Area (WUCA). If the SWFWMD has established, or establishes in the future, a WUCA for the region that encompasses the location of the Osprey Energy Center, at such time as the Governing Board adopts such special regulations, the SWFWMD shall initiate any required action to make the Permittee subject to them upon notice and after a reasonable period for compliance.

11. The Permittee shall mitigate, to the satisfaction of the SWFWMD, any adverse impact to existing legal uses caused by withdrawals from the project withdrawals. When adverse impacts occur or are imminent, the SWFWMD shall require the Permittee to mitigate the impacts. Adverse impacts include, but are not limited to:

a. a reduction in water levels which impairs the ability of a well to produce water;

b. significant reduction in levels or flows in water bodies such as lakes, impoundments, wetlands, springs, streams or other watercourses; or

c. significant introduction of natural or manmade contaminants into a water supply or into a usable portion of any aquifer or water body.

12. The Permittee shall mitigate to the satisfaction of the SWFWMD any adverse impact to environmental features or off-site land uses caused by the project withdrawals. When adverse impacts occur or are imminent, the SWFWMD shall require the Permittee to mitigate the impacts. Adverse impacts include the following:

a. significant reduction in levels or flows in water bodies such as lakes, impoundments, wetlands, springs, streams, or other watercourses;

b. sinkholes or subsidence caused by reduction in water levels;

c. damage to crops and other vegetation causing financial harm to the owner; and
Damage to the habitat of endangered or threatened species.

B. Specific Conditions

1. A SWFWMD identification tag shall be prominently displayed at each withdrawal point by permanently affixing the tag to the withdrawal facility.

2. The Permittee must notify the SWFWMD within 30 days of the sale or transfer of permitted water withdrawal facilities or the land on which the facilities are located.

3. All plans or reports pertaining to water use and or management as required by these Conditions of Certification shall be submitted to the SWFWMD on or before the tenth day of the month following data collection and shall be addressed to:

Permit Data Section, Records and Data Department
Southwest Florida Water Management District
2379 Broad Street
Brooksville, Florida 34604-6899

Unless otherwise indicated, three copies of each plan or report, with the exception of pumpage, rainfall, evapotranspiration, water level or water quality data which require one copy, are required by these Conditions of Certification.

4. Water Supply

a. Since the Osprey Energy Center will receive increasing quantities of reclaimed water of suitable quality from the City of Auburndale's Allred Wastewater Treatment Plant (WWTP), phased reductions in the ground water withdrawals will be required.

(1) The groundwater withdrawal quantities [i.e. the total combined withdrawals from SWFWMD ID Nos. 1, 2, and 3, (Osprey Energy Center ID Nos. 1, 2, and 3)] in gallons per day (gpd) will be decreased in approximate proportion to the increased use of reclaimed water as follows:

Calendar Year	Allred WWTP Annual Average (gpd)	Groundwater Withdrawal Annual Average (gpd)	Groundwater Withdrawal Peak Month (gpd)
2002	807,800	2,742,200	4,006,000
2003	837,700	2,722,300	3,977,000
2004	857,600	2,712,400	3,957,700
2005	887,600	2,682,400	3,928,600
2006	917,500	2,672,400	3,899,600
2007	937,400	2,652,600	3,880,300
2008	967,300	2,642,800	3,851,200
2009	997,300	2,632,700	3,822,200
2010	1,027,200	2,602,800	3,793,100

2011	1,047,100	2,582,900	3,773,800
2012	1,077,000	2,573,000	3,744,700
2013	1,107,000	2,543,000	3,715,700
2014	1,136,900	2,536,900	3,686,700
2015	1,156,800	2,523,200	3,667,300
2016	1,186,700	2,516,700	3,638,300
2017	1,216,700	2,486,700	3,609,200
2018	1,246,600	2,483,400	3,580,200
2019	1,266,700	2,463,500	3,560,900
2020	1,296,400	2,433,600	3,531,800
2021	1,346,300	2,413,700	3,483,800
2022	1,396,200	2,393,800	3,343,500

(2) To the extent that the Osprey Energy Center receives the quantity of suitable quality reclaimed water from the Allred WWTP during a calendar year, as specified in Condition XIV.B.4.a.(1), the Osprey Energy Center may not exceed the corresponding ground water use allowance.

(3) To the extent that the Osprey Energy Center does not receive the quantity of suitable quality reclaimed water from the Allred WWTP during a calendar year, as specified in Condition XIV.B.4.a.(1), the Osprey Energy Center may not exceed a combined total reclaimed water and ground water Annual Average quantity of 3,790,000 gpd nor a combined total reclaimed water and ground water Peak Month quantity of 4,740,000 gpd. In no case is the Osprey Energy Center authorized to withdraw ground water in excess of an Annual Average of 2,742,200 gpd nor a Peak Month quantity in excess of 4,006,000 gpd.

(4) The Annual Average Daily and Peak Month Daily quantities for SWFWMD ID Nos.1, 2, and 3, (Osprey Energy Center ID Nos. 1, 2, and 3), shown above in the production withdrawal table are estimates based on historic and/or projected distribution of pumpage, and are for water use inventory and impact analysis purposes. The quantities listed in the table for these individual sources are not intended to dictate the distribution of pumpage from permitted sources. The Permittee may make adjustments in pumpage distribution as necessary up to the quantities indicated specifically for each withdrawal provided that the combined total quantities will not exceed 2,742,200 gpd on an average basis and 4,006,000 gpd on a peak monthly basis. In all cases, the total average annual daily withdrawal and the total peak monthly daily withdrawal are limited to the quantities set forth above.

b. The Osprey Energy Center is not required to accept reclaimed water in amounts which exceed the power plant's demand and storage capacity.

5. No later than April 1, of each year, the Permittee shall submit to SWFWMD and the Department a water use summary report for the preceding calendar year. The summary shall include:

a. Water use source and quantity data;

b. The Monthly Average Daily and Annual Average Daily quantities of reclaimed water received from the Allred WWTP;

c. The Monthly Average Daily and Annual Average Daily quantities of ground water pumpage;

d. The Monthly Average Daily and Annual Average Daily totals of reclaimed and ground water received; and

e. If the Osprey Energy Center does not receive the quantity of suitable quality reclaimed water from the Allred WWTP, as specified in Condition XIV.B.4.a.(1), and exceeds the corresponding Annual Average Daily or Peak Month Daily ground water withdrawal allowance during the same calendar year, the permittee shall explain why the receipt of reclaimed water from the Allred WWTP was less than projected.

6. The Permittee shall continue to investigate the feasibility of using additional reclaimed water as a water source and submit a report describing the findings of the feasibility investigation to the Permits Data Section no later than April 1, of the years 2007, 2012, and 2017. The report shall contain an analysis of potential reclaimed water sources in the area, including the location of those sources, the quantity of reclaimed water available, the projected date(s) of availability, and costs associated with obtaining and transporting the reclaimed water to the Osprey Energy Center site. At such time as the SWFWMD determines that use of additional reclaimed water is environmentally, technically, and economically feasible, an implementation schedule shall be developed and these Conditions of Certification shall be modified to reduce, by the amount of additional reclaimed water, the quantity of ground water authorized for consumption by the Osprey Energy Center.

7. Within 90 days of issuance of the Site Certification or completion of construction of the withdrawal facility, whichever is later, and prior to the activation of a stand-by source, SWFWMD ID Nos. 1, 2 and 3, Osprey Energy Center ID Nos. 1, 2, and 3, shall be equipped with non-resettable, totalizing flow meter(s), or other measuring device(s) as approved in writing by the SWFWMD Regulation Department Director, Resource Regulation unless an extension is granted by the Director. Such device(s) shall have and maintain an accuracy within five percent of the actual flow as installed. Total withdrawal and meter readings from each metered withdrawal shall be recorded on a monthly basis and reported to the Permit Data Section (using SWFWMD forms) on or before the tenth day of the following month. If a metered well is not utilized during a given month, a report shall be submitted to the Permit Data Section indicating zero gallons. Prior to meter installation, non-use shall be documented with monthly pumpage reports indicating zero gallons withdrawn.

8. Within 90 days of issuance of the Site Certification or 90 days prior to the delivery of reclaimed water, whichever is later, the reclaimed water delivery point, SWFWMD ID No. 50, Osprey Energy Center ID No. R-1, through which reclaimed water will be received at the Osprey Energy Center, shall be equipped with non-resettable totalizing flow meters, or other flow measuring devices or methods as approved in writing by the Regulation Department Director,

Resource Regulation. Such devices or methods shall have and maintain an accuracy within 5 percent of the actual flow as installed. Total flow and meter readings from the metered flow shall be recorded on a monthly basis and reported to the Permit Data Section (using SWFWMD forms) on or before the 10th day of the following month.

9. Well Water Sampling

a. Water quality samples shall be collected and analyzed as specified below.

SWFWMD ID No.	Osprey Energy Center ID No.	Minimum Pumping Time (minutes)	Sampling Parameters	Months
1	1	30	Chlorides, Sulfates, TDS	February May August November

Note: samples shall be collected in the first week of the sampling month.

b. Analyses shall be performed according to procedures outlined in the current edition of Standard Methods for the Examination of Water and Wastewater by the American Public Health Association-American Water Works Association-Water Pollution Control Federation (APHA-AWWA-WPCF) or Methods for Chemical Analyses of Water and Wastes by the U.S. Environmental Protection Agency (EPA).

c. Water quality samples from production wells shall be collected whether or not the well is being used, unless infeasible. If sampling is infeasible the Permittee shall indicate the reason for not sampling on the water quality data form. Water quality samples shall be analyzed by a Department of Health and Rehabilitative Services (DHRS) certified laboratory under Environmental Laboratory Certification General Category "1". At a minimum, water quality samples shall be collected after pumping the well at its normal rate for a pumping time specified in condition a. above, or to a constant temperature, pH, and conductivity. In addition, the Permittee's sampling procedure shall follow the handling and chain of custody procedures designated by the certified laboratory that will undertake the analysis. Any variance in sampling and/or analytical methods shall have prior approval of the Regulation Department Director, Resource Regulation. Reports of the analyses shall be submitted to the Permit Data Section (using SWFWMD forms) on or before the tenth day of the following month, and shall include the signature of an authorized representative and certification number of the certified laboratory which undertook the analysis. The parameters and frequency of sampling and analysis in these Conditions of Certification may be modified as necessary to ensure the protection of the resource.

10. Within 90 days of completion of construction of the power generation facility, the Permittee shall install and maintain a continuous recording rain gauge in the area around

SWFWMD ID No. 1: Total daily rainfall shall be recorded at this station and submitted to the Permit Data Section, on SWFWMD forms on or before the tenth day of the following month. The reporting period for these data shall begin on the first day of each month and end on the last day of each month. Final location shall be submitted plotted on an original blue line aerial map or United States Geological Survey quadrangle map, or by providing latitude - longitude location.

11. Any wells not in use, and in which pumping equipment is not installed shall be capped or valved in a water tight manner in accordance with Chapter 62-532.500(3)(a)(4), F.A.C.

12. Well Construction

a. The Permittee shall construct all wells according to the surface diameter and a casing depth specifications below. NOTE: The casing depth specified is to prevent the unauthorized interchange of water between different water bearing zones. When a total depth is listed, it is an estimate based on best currently available information of the depth at which high producing zones are encountered. However, during well construction, it is the Permittee's responsibility to have the water in the well sampled before reaching the estimated total depth. This is to ensure that the well does not encounter water of a quality that cannot be utilized at the Ospery Energy Center and to ensure that withdrawals from the well will not cause salt-water intrusion.

SWFWMD ID No.	Osprey Energy Center ID No.	Surface Diameter	Minimum Cased Depth	Estimated Total Depth
1	1	16"	150'	700'
2	2	16"	150'	700'
3	3	16"	150'	700'

b. The casing shall be continuous from land surface to the minimum depth stated above.

c. All well casing (including liners and/or pipe) must be sealed to the depth specified in Condition a. above.

d. The wells shall be constructed of materials that are resistant to degradation of the casing and grout.

e. A minimum grout thickness of two (2) inches is required on wells four (4) inches or more in diameter.

f. A minimum of twenty (20) feet overlap and two (2) centralizers are required for Public Supply wells, and all wells six (6) inches or more in diameter.

g. The finished well casing depth shall not vary from these specifications by greater than ten (10) percent unless advance approval is granted by the Regulation Department Director, Resource Regulation, or the Supervisor of the Well Construction Permitting Section in Brooksville.

h. Advance approval from the Regulation Department Director, Resource Regulation is necessary should the Permittee propose to change any well location or casing diameter.

13. Aquifer Performance Test (APT)

a. At least one year prior to the planned withdrawals from the first of SWFWMD ID No. 1 through 3, (Osprey Energy Center ID No. 1 through 3), the permittee shall submit a detailed plan for a long-term aquifer performance test for approval by the Regulation Department Director, Resource Regulation.

b. The test shall be conducted for a sufficient length of time to allow determination of the leakance parameter between the surficial and intermediate aquifers and the leakance parameter between the intermediate and Upper Floridan aquifers.

c. The test shall include collection of water quality data as specified in Condition XIV.B.9.a.

d. To the best of the permittee's ability, test shall be conducted during a period of minimum nearby pumpage and during a period of minimum rainfall to minimize interference with the test.

e. The test shall take place prior to initiation of pumpage from the Osprey Energy Center wells.

f. A report of the results of the test, including all raw data and analyses, shall be provided to the Permit Data Section within 30 days of the completion of the test.

g. If SWFWMD determines that any of the aquifer characteristics vary significantly from those used in the groundwater flow model submitted with the SCA, the Permittee shall submit an updated groundwater flow model to the Regulation Department Director, Resource Regulation. This model shall utilize the actual aquifer characteristics determined during the APT to predict impacts due to groundwater withdrawals at this site. If new modeling is required and it indicates that there are adverse impacts not indicated in the SCA, the Permittee may be required to amend the SCA or seek modification of these Conditions of Certification in accordance with Condition XI.

14. The Permittee shall begin carrying out the provisions of its SWFWMD approved conservation plan, dated March 30, 2000, upon receipt of this Certification. The Permittee shall submit progress reports concerning implementation of the plan on April 1, of the years 2007, 2012, and 2017.

C. Surface Water

There will be no intake from or direct discharge to surface Waters of the State associated with the construction or operation of the Osprey Energy Center.

D. Water Resource Complaints

1. The Permittee shall investigate water resource complaints within the area within 425 feet of the property boundary. The complaint handling/mitigation procedure shall be as follows:

a. Within 48 hours of notification of a complaint, the Permittee shall perform a preliminary investigation to determine if the Osprey Energy Center's withdrawals are the cause of the problem stated in the complaint..

(1) If the preliminary investigation indicates that the Osprey Energy Center withdrawals are responsible, the Permittee shall:

(a) within 72 hours of notice of complaint, supply the complainant with any water necessary for health and safety purposes; and

(b) conduct a detailed investigation of the complaint and if the detailed investigation confirms that the complainant's problem was caused by the Osprey Energy Center's withdrawals, corrective action shall be undertaken by the Permittee within 15 days of notice of complaint.

(2) If the preliminary assessment indicates that Osprey Energy Center withdrawals are not responsible for the complainant's problem, the Permittee shall document the reasons for this determination

b. The Permittee shall file a report of the complaint investigation with the Regulation Department Director, Resource Regulation, for review and approval within 20 days of the receipt of notice of complaint.

(1)The report shall include:

(a) the name and address of the complainant;

(b) the date and nature of the complaint;

(c) a summary of the permittee's investigation;

(d) a summary of the permittee's determination, including details of any mitigation activities; and

(e) cost of mitigation activity for each complaint.

(2) A copy of the report shall also be sent to the complainant within 20 days of notice of complaint.

XV. SOLID AND HAZARDOUS WASTE MANAGEMENT

A. No solid or hazardous waste is to be permanently stored onsite.

B. Any salt cake from the industrial wastewater treatment and cooling water systems is to be sent off-site for disposal.

XVI. INDUSTRIAL WASTEWATER

All industrial wastewater is to be discharged into an underground pipeline owned and operated by the City of Auburndale and through which the wastewater is conveyed to the City of Auburndale's Wastewater Treatment Plants. Should there be any change in the conveyance or treatment system that adversely affects the treatment of wastewater from the Osprey Energy Center, these Conditions of Certification may need to be be modified in accordance with Condition XI.

XVII. DOMESTIC WASTEWATER

All domestic wastewater is to be discharged into an underground pipeline owned and operated by the City of Auburndale and through which the wastewater is conveyed to the City of Auburndale's Wastewater Treatment Plants. Should there be any change in the conveyance or treatment system that adversely affects the treatment of wastewater from the Osprey Energy Center, these Conditions of Certification may need to be modified in accordance with Condition XI.

XVIII. POTABLE WATER

Potable water is to be received from the existing City of Auburndale potable water treatment and distribution system. Should there be any change in this system that adversely affects the delivery of adequate potable water to the Osprey Energy Center these Conditions of Certification may need to be modified in accordance with Condition XI.

XIX. STORMWATER MANAGEMENT

A. Contact stormwater runoff (rainfall that has come in contact with industrial equipment or processes) is to be completely contained and recycled as process water or entered into the process wastewater stream directly.

B. Construction on the Osprey Energy Center site must meet the requirements of Rules 62-25, F.A.C. and 62-17.211, F.A.C., as well as the design requirements presented in the Site Certification Application. Stormwater facilities associated with the Osprey Energy Center will not become operational until an engineer practicing in the State of Florida in compliance with Section 471.003, F.S. and with the appropriate experience in surface water design, certifies that these facilities have been constructed in accordance with the design as approved by the Department.

C. All stormwater is to be discharged into the stormwater treatment units. Should there be any change in site layout or these treatment units that adversely affect the treatment of stormwater, these Conditions of Certification must be modified in accordance with Condition XI.

XX. TRANSPORTATION

A. Traffic control will be maintained during plant construction and maintenance in compliance with the applicable standards contained in the Manual on Uniform Traffic Control Devices; Statewide Minimum Level of Service Standards, Rule Chapter 14-94, Florida Administrative Code; Florida Department of Transportation's Roadway and Traffic Design Standards; and Florida Department of Transportation Standard Specifications for Road and Bridge Construction, whichever is more stringent.

B. For the delivery of any overweight or overdimensional loads to the site during the construction of the Facility, the permittee or their contractors shall adhere to the necessary standards and receive the necessary permits required under Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

C. No new permanent access to the State Highway System is proposed in the site certification application. Any temporary construction access must meet permitting requirements as defined in Rule Chapters 14-96, State Highway System Connection Permits, Administrative Process, and 14-97, State Highway System Access Management Classification System and Standards, Florida Administrative Code.

D. Any use of State of Florida right of way or transportation facilities is subject to the requirements of the Department of Transportation's Utility Accommodation Manual (Document 710-020-001) and Rule 14-46.001, Railroad/Utility Installation or Adjustment, Florida Administrative Code.

E. Operation of overweight/overdimensional vehicles by the Permittee on State trsansportation facilities during construction and operation of the Osprey Energy Center will be subject to the requirements of Chapter 316, F.S., and Rule Chapter 14-26, F.A.C., *Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles.*

F. Any drainage onto State of Florida right of way or transportation facilities is subject to the requirements of Rule Chapter 14-86, Drainage Connections, Florida Administrative Code.

XXI. EMERGENCY MANAGEMENT

A. The Permittee shall develop a Comprehensive Hurricane Preparation and Recovery Plan for the Osprey Energy Center and shall submit that plan to the Department of Community Affairs and the Polk County Office of Emergency Management no later than commencement of construction of the Osprey Energy Center.

B. The Permittee shall submit a formal update of the Comprehensive Hurricane Preparation and Recovery Plan to the Department of Community Affairs and the Polk County Office of Emergency Management every five (5) years following commencement of commercial operation of the Osprey Energy Center.

ATTACHMENT

Prevention of Significant Deterioration Permit

PSD- FL-287

PERMITTEE:

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

File No.	PSD-FL-287 (PA00-41)
FID No.	1050334
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 527 megawatt (MW) Combined Cycle plant consisting of: two nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; two supplementally-fired heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two stacks; an emergency (gas-fired) generator; a diesel fire pump; two selective catalytic reduction units including ancillary equipment and ammonia storage. The combined cycle plant will achieve approximately 585 megawatts in combined cycle operation during extreme winter peaking conditions. The facility is designated as Osprey Energy Center and will be situated adjacent to the Auburndale Power Partners facility, which is located at 1501 Derby Avenue, Auburndale, Polk County. UTM coordinates are: Zone 17; 421.0 km E; 3103.2 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 Osprey Energy center is a nominal 527 MW combined cycle plant. It will include: two nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; two supplementally-fired heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two stacks; an emergency (gas-fired) generator; a diesel fire pump; two selective catalytic reduction units including ancillary equipment and ammonia storage. New major support facilities include a cooling tower, water and wastewater facilities and a transmission line.

Emissions from Osprey 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 170 Megawatt Gas Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
003	Steam Generation	One 250 MMBtu/hr Duct Burner configured as a Supplementally Fired Heat Recovery Steam Generator
004	Steam Generation	One 250 MMBtu/hr Duct Burner configured as a Supplementally Fired Heat Recovery Steam Generator
005	Water Cooling	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 is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is greater than 75 MW. [Chapter 403.503 (12), F.S., Definitions]

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

PERMIT SCHEDULE

- xx/xx/00 PSD Permit Issued
- xx/xx/00 Site Certification Issued
- xx/xx/00 Notice of Intent to Issue PSD Permit published in xxxxxxxxxxxx
- xx/xx/00 Distributed Revised Intent to Issue PSD Permit
- 04/28/00 Distributed Intent to Issue Permit
- 03/30/00 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 March 30, 2000.
- Department's Intent to Issue and Public Notice Package dated May 10, 2000.
- Department's Draft Permit and Draft BACT determination dated May 10, 2000.
- Letters from EPA Region IV dated February 2 and November 8, 1999.
- Letter from Fish & Wildlife Service dated April 17, 2000.
- Site Certification for the Osprey Energy Center dated xx/xx/00.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

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 Blairstone 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 Southwest District Office, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 and phone number 813/744-6100.
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 Southwest 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 Southwest 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 Southwest 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 and 002. 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).
5. ARMS Emissions Units 003 and 004. Steam Power Generation, each consisting of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 250 MMBTU/hr duct burner (HHV) and combined with a 200 MW steam electrical generator 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.
6. ARMS Emission Unit 005. Cooling Tower, is an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.
7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District Office.

GENERAL OPERATION REQUIREMENTS

8. Fuels: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
9. 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 1,669 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)]

10. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 250 MMBtu/hour (LHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. 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.

12. 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 Southwest 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.]

13. 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.]

14. 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.]

15. Maximum allowable hours of operation for the 527 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)]

16. 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

17. 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.]

18. 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)]

19. Drift eliminators shall be installed on the cooling tower 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.

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, the duct burner on or off, shall not exceed 3.5 ppmvd @15% O_2 on a 24-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 27.5 lb/hr (at 95°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). [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 9.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 46. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

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 45 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 2.3 ppmvd @15% O_2 nor 5.8 lb/hr per unit with the duct burner off and neither 4.6 ppmvd @15% O_2 nor 12.4 lb/hr 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 2 grains per 100 standard cubic foot). Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 43 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 and EU-002 at 95.4 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 24.1

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 24-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 Southwest 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 46, 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.
- EPA Method 26A (modified) for ammonia sample collection (I, A).
- EPA Draft Method 206 for ion chromatographic analysis for ammonia (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 46.

30. Continuous compliance with the CO and NO_X emission limits: 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. Valid hourly emission rates shall not include periods of start up or shutdown unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two measurements are obtained at least 15 minutes apart. 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. Compliance with the SO_2 and PM/PM_{10} emission limits: 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. Compliance with CO emission limit: 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. Compliance with the VOC emission limit: 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. Testing procedures: 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 Southwest 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 Southwest 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 nitrogen oxides and carbon monoxide from these units. Periods when emissions (ppmvd @ 15% oxygen) are above the permitted limits, listed in Specific Conditions No. 20 and 21 shall be reported to the DEP Southwest District Office in accordance with the requirements of Specific Condition 27. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

41. CEMS for reporting excess emissions: The CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards listed within this permit and established in 40 CFR 60.332.

42. 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.

43. 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.

44. 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]

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

46. 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.
- The permittee shall notify the Department within 2 business days if the calculated ammonia emissions exceed 9.0 ppmvd corrected to 15% O_2 over a 3-hour block average. The notification shall include a corrective action plan to reduce ammonia emissions below 9 ppmvd corrected to 15% O_2 over a 3-hour block average.
- 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.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Calpine Construction & Finance Company, LP

Osprey Energy Center
527 Megawatt Combined Cycle Facility

Auburndale, Polk County

PSD-FL-287, PA00-41

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

May 10, 2000

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

03-30-00: Date of Receipt of Application
05-10-00: Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The Osprey Energy Center is located adjacent to the existing Auburndale Power Partners facility, Auburndale, Polk County. This site is approximately 102 kilometers from the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates of this facility are Zone 17; 421.0 km E; 3103.2 km N. See Figures 1 and 2 below.

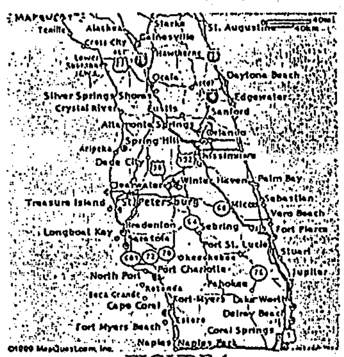

FIGURE 1

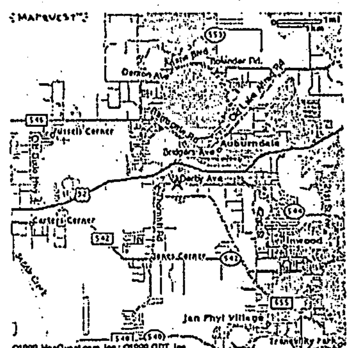

FIGURE 2

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 170 Megawatt Gas Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
003	Steam Generation	One 250 MMBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator
004	Steam Generation	One 250 MMBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator
005	Water Cooling	Cooling Tower

Calpine Construction Finance Company, LP (Calpine) proposes to construct a nominal 527 megawatt (MW) combined cycle plant to be situated adjacent to the existing Auburndale Power Partners facility which is located at 1501 Derby Avenue, Auburndale in Polk County. The project includes: two nominal 170 MW Westinghouse 501FD combustion turbine-electrical generators operating solely on natural gas; two 250 million Btu per hour (MMBtu/hr) supplementally-fired heat recovery steam generators (HRSG); a 200 MW (gross output) steam turbine; two stacks; an emergency (gas-fired) generator; a diesel fire pump; a fresh water 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 ~4 ppmvd at 15% O_2. The turbines will each have a nominal heat input rating of 1,669 MMBtu/hr at a lower heat value (LHV) of 920 MMBtu/MCF while operating at 100% load.

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.

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.

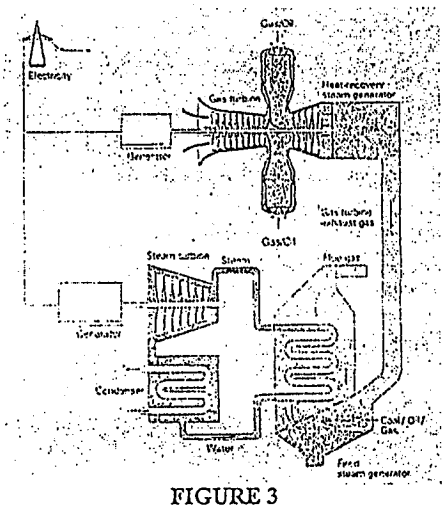

FIGURE 3

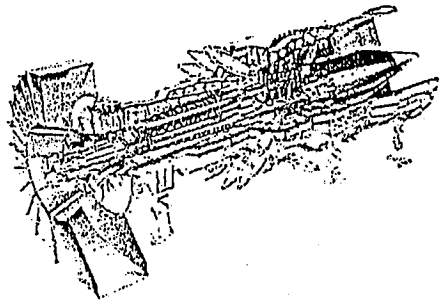

FIGURE 4

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 Polk 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 mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 20 through 24 of Draft Permit PSD-FL-287.

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	2 CT/HRSG with Duct Burners[1]	Cooling Tower	Emergency Generator and Diesel Fire Pump[2]	Total	PSD Significance	PSD REVIEW?
PM/PM_{10}	190/190	8.6/4.3	0.37	199/194	25	Yes
SO_2	95	0	0.062	95	40	Yes
NO_X	218	0	8.6	227	40	Yes
CO	792	0	4.83	797	100	Yes
Ozone(VOC)	69.1	0	0.47	70	40	Yes
Sulfuric Acid Mist	14.6	0	Neg.	15	7	Yes
Mercury	0.000014	0	Neg.	0.000014	0.1	No
Lead	Neg.	0	Neg.	Neg.	0.6	No

1. Based on 5880 hours/year at 100% output, 59 °F compressor inlet temperature and 2880 hours/year at 100% output using power augmentation with duct burners on at 95°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 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: SO_2/SAM, PM/PM_{10}, CO, NO_X, and VOC. SO_2, PM_{10} and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO and VOC are criteria pollutants and have only AAQS and significant impact levels defined for them. Since the project's VOC emissions increase is less than 100 tons per year no air quality analysis is required for VOC. 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.

The applicant's initial SO_2, PM_{10}, CO and NO_X air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. The nearest PSD Class I area is the Chassahowitzka National

Wilderness Area located 102 km to the northwest. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for SO_2, PM_{10}, CO and NO_X;
- 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 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) and California Puff (CALPUFF) dispersion models were used to evaluate the pollutant emissions from the proposed project. The ISCST3, Version 99155, dispersion model (EPA, 1999) was used to evaluate the maximum pollutant impacts due to the project in nearby areas surrounding the site. The ISCST3 model is generally applicable for estimating the air quality impacts in areas that are within 50 km from a source. This model is maintained by EPA on its Internet website and is designed to calculate hourly concentrations based on hourly meteorological data. The ISCST3 model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

At distances beyond 50 km from a source, the CALPUFF model, Version 5.0 (EPA, 1998) is recommended for use by the EPA and the FDEP. The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The methods and assumptions used in the CALPUFF model were based on the latest recommendations for modeling analysis as presented in the *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998). This model is also maintained by the EPA on its website. Accordingly, the CALPUFF model was used to perform the significant impact and regional haze analyses at the Chassahowitzka NWA for the project.

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent five-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Tampa International Airport and Ruskin, Florida respectively. The five-year period of meteorological data used was from 1987 through 1991, which are the latest readily available data for these stations that are acceptable to

FDEP. The NWS station at Tampa is located approximately 42 miles west of the proposed site while the NWS station at Ruskin is located approximately 45 miles southwest of the proposed site.

These meteorological data are the most complete and representative of the region around the site because both the site and the weather stations are located in areas that experience similar weather conditions, such as frontal passages. In addition, these data have been approved for use by the FDEP in previous air permit applications to address air quality impacts for other proposed sources locating in Polk and adjacent counties.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the SCREEN3 model was used to evaluate dispersion of emissions from the combined cycle facility for three loads (60%, 75% and 100%) and three seasonal operating conditions (summer, winter and average). Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If this modeling (at worst load conditions) shows significant impacts, additional multi-facility modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments.

For predicting maximum concentrations in the vicinity of the project, a polar receptor grid was used which consisted of 729 receptors. These receptors included 36 receptors located on radials extending out from the proposed stack location for HRSG No.1. Along each radial, receptors were located beginning at the fenced plant property and extending to distances of 100; 200; 300; 400; 500; 700; 1000; 1500; 2000; 2500; 3000; 4000; 5000; 7000; 10000; 12000; 15000; 20000; 25000; and 30000 meters. However, concentrations were predicted only at receptors located off plant property that would be considered ambient air locations. As a result, because the proposed plant property extends out from a minimum distance of about 60 m in several directions to about 330 m for other directions, there were directions for which receptors were not modeled at certain distances (e.g., 200m) which would not be considered ambient air locations.

For each pollutant and averaging time, modeling refinements were performed, as needed, by employing a Cartesian receptor grid with a maximum spacing of 100 m centered on the receptor and for the year during which the maximum impact from the project was predicted. For the Class I analysis, the maximum concentrations were predicted at 13 receptors surrounding the PSD Class I area of the Chassahowitzka NWA (CNWA). These receptors have been provided by the FDEP for use on the previous applications. The tables below show the results of this modeling.

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

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.051	1	NO
	24-hour	1.35	5	NO
	3-hour	7.48	25	NO
PM_{10}	Annual	0.26	1	NO
	24-hour	4.5	5	NO
CO	8-hour	79	500	NO
	1-hour	427	2000	NO
NO_2	Annual	0.14	1	NO

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

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.0014	0.1	NO
	24-hour	0.024	0.2	NO
	3-hour	0.072	1.0	NO
PM_{10}	Annual	0.0034	0.2	NO
	24-hour	0.052	0.3	NO
NO_2	Annual	0.0014	0.1	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and VOC as a result of the proposed project, including background concentrations and all other nearby sources, will be less than 1 percent of their respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels, which in-turn is less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

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 results of the refined CALPUFF analysis predicted a change in visibility of 0.47%. This impact is well below the National Park Service-recommended threshold of 5%, and it indicates that the proposed project will not have an adverse impact on visibility and regional haze in the CNWA.

Growth-Related Air Quality Impacts

The applicant projects that there will be only short-term increases in the labor force to construct the project and that it will not result in permanent, significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require approximately 25 permanent employees, which should not cause a significant impact to the local area.

On a larger scale, a project review is required by the Public Service Commission, who has previously determined that power projects are needed to help meet the low electrical reserves throughout the State of Florida. The project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," minimal ground water requirements and will be one of the lowest regional air pollutant emitters per unit of electric power generating capacity.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any 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
A. A. Linero, P.E., NSR Administrator
Cleve Holladay, Meteorologist

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Osprey Energy Center
Calpine Construction Finance Company, L.P.
PSD-FL-287 and PA00-41
Auburndale, Polk County, Florida

BACKGROUND

The applicant, Calpine Construction Finance Company, L.P. (Calpine), proposes to build a 527 MW (average ambient net megawatts) combined cycle power plant as a new facility. The location of the proposed plant is adjacent to the existing Auburndale Power Partners facility, in Auburndale, Polk 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). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two 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 two heat recovery steam generators (HRSGs), each with a 135 ft. stack and one steam turbine-electrical generator rated at approximately 200 MW. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes a mechanical draft cooling tower, 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 May 10, 2000, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on March 30, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Golder Associates. 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	2 grains S / 100 scf
CO	Pipeline Natural Gas Good Combustion	10 ppmvd 16 ppmvd with Duct Burners on (DB) 25 ppmvd during power augmentation (PA) 30 ppmvd during DB plus PA
VOC	Pipeline Natural Gas Good Combustion	2.3 ppmvd 4.6 ppmvd during DB plus PA
NO_X	DLN & SCR	4.0 ppmvd
PM (cooling tower)	High efficiency drift eliminators	0.002% drift loss

Based upon the applicant's submittal, the maximum annual emissions that the facility has the potential to emit (PTE) are as follows: 95 TPY SO_2, 15 TPY SAM, 199 TPY PM/PM_{10}, 258 TPY NO_X, 797 TPY CO and 70 TPY of VOC.

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 gas-fired emergency generator and diesel 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
Lake Worth LLC, FL	250	9/3.5 - NG (CT) 9.4/3.5 - (CT&DB) 42 - FO	DLN/SCR DLN/SCR WI	170 MW GE 7FA. 11/99 Increase allowed for DB. Project repowers one + units
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 (proposed)	545	4.0 – (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
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
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 (proposed)	10 – NG (CT only) 16 – NG (CT & DB) 30 – NG (DB & PA)	2.3 – NG (CT) 4.6 – NG (DB & PA)	10% Opacity 24.1 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 250 MMBtu/hr compared with the turbine that can accommodate a heat input greater than 1600 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.

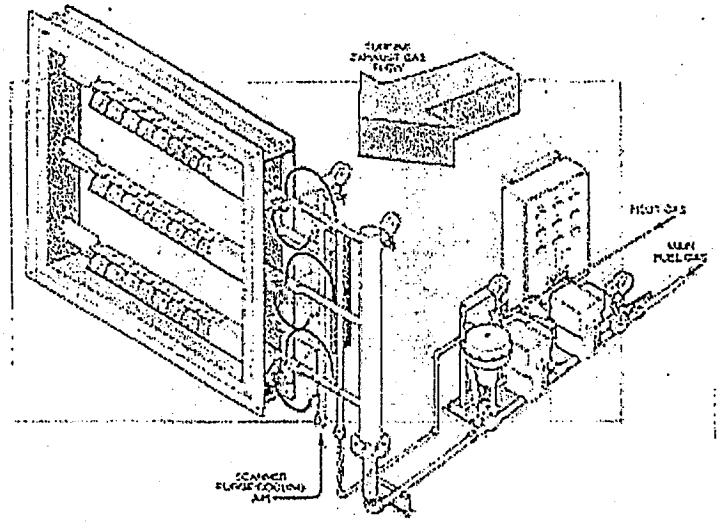

FIGURE A

Selective Catalytic Combustion

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

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

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

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.

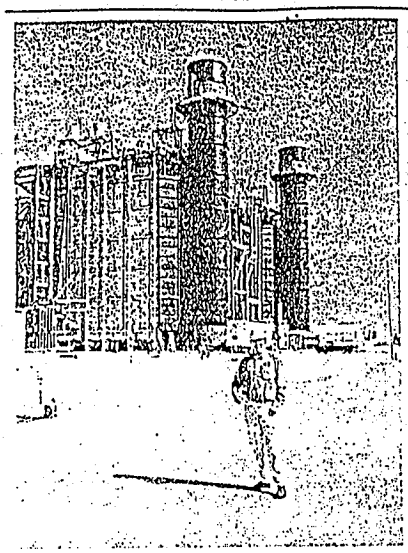

Figure B

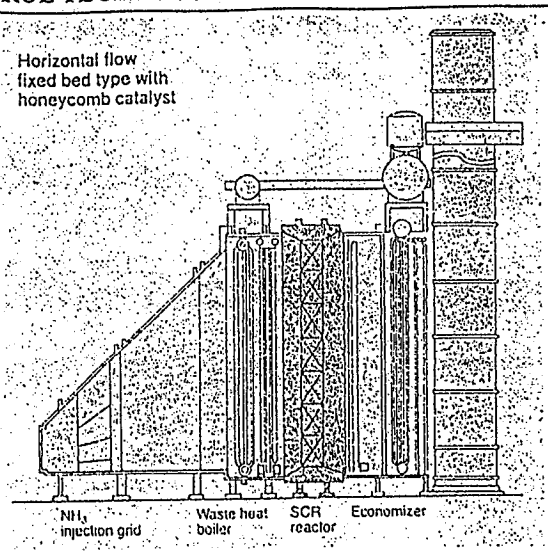

Figure C

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 have been specified using SCR for at least one F Class project (with large in-line duct burners) in the Southeast and lower in the southwest.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. 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. The oxygen levels greater than 12%, which are expected in this application, cause SNCR to not be technically feasible for the Calpine Osprey project.

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 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.

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

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

Natural gas is an inherently clean fuel and contains no ash. Natural gas will be the only fuel fired at the Osprey 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 from the fresh-water cooling tower, due to an approximate 1400-ppm of suspended solids resulting from the use of reclaim water. Accordingly, drift eliminators shall be installed on the fresh-water cooling tower 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. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for this type of cooling tower.

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 16, 25 and 30 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 16 ppmvd x 2/24 hours plus 25 ppmvd x 2/24 hours plus 30 ppmvd x 2/24 hours plus 50 ppmvd x 2/24 hours}

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 4.2 ppm with the duct burner off (between 60% and 70% output) and 4.6 ppm with the duct burner on during power augmentation. According to the applicant's submittals, VOC emissions less than 3 ppm will be achieved at 100% output and duct burners off. [5]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 24.1 lb/hr during DB plus PA 9 ppmvd Ammonia Slip
SO_2 / SAM	Pipeline Natural Gas	2 grains S / 100 scf
VOC	Pipeline Natural Gas Good Combustion	2.3 ppmvd 4.6 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 45 lb/hr w/o DB plus PA
NO_X (all operating modes)	DLN & SCR	3.5 ppmvd (SCR) DB limited to 0.1 lb/MW-hr 27.5 lb/hr during DB plus PA
PM (cooling tower)	High efficiency drift eliminators	0.002% 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 has 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 considered a shorter (3-hour) averaging time for NO_X compliance, but was ultimately persuaded to provide the higher (24-hour) averaging time due to Calpine's BACT proposal being the first one submitted in Florida where a low (4.0 ppmvd) emission rate SCR was proposed by the applicant. FDEP intends to issue subsequent BACT Determinations with lower averaging time requirements.
- 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 2.3 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
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 24-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	EPA Method 26A (modified) and Draft Method 206 (Annual)

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.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
A. A. Linero, P.E. Administrator, New Source Review Section
Cleve Holladay, Meteorologist, New Source Review Section
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Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

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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 Table A-2, referencing Siemens-Westinghouse. Calpine Osprey Energy Center application received 3-30-2000.

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.