Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 4, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Re: Okeelanta Power Limited Partnership
Cogeneration Plant – Addition of Natural Gas
Project No. 0990332-013-AC
Draft Permit No. PSD-FL-196L

Dear Mr. Cepero:

Enclosed is one copy of the Draft Permit modification to add natural as a supplemental fuel to the biomass boilers at the Okeelanta Cogeneration Plant located near the city of South Bay in western Palm Beach County. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

, P.E.

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

CHF/AAl/jfk

Enclosures

7099 3400 0000 1453 3341

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

Article Sent To:

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

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Gus Cepero
Street, Apt. No.; or PO Box No.
PO Box 9
City, State, ZIP+4
South Bay, FL 33493

PS Form 3800, July 1999 — See Reverse for Instructions

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Gus Cepero
Okeelanta Power Limited
Partnership
PO Box 9
South Bay, FL 33493

4a. Article Number
7099 3400 0000 1453 3341

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
12-7-00

5. Received By: *(Print Name)*
Kathy Yerkes

6. Signature: *(Addressee or Agent)*
X Kathy Yerkes

8. Addressee's Address *(Only if requested and fee is paid)*

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 — 102595-97-B-0179 — Domestic Return Receipt

In the Matter of an
Application for Air Permit by:

Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Authorized Representative:
Gus Cepero

Project No. 0990332-103-AC
Draft Permit No. PSD-FL-196L
Okeelanta Cogeneration Plant
Project: Addition of Natural Gas
Palm Beach County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project, as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. Okeelanta Power Limited Partnership applied on June 20, 2000 to the Department for an air construction permit to add natural as a supplemental fuel to the biomass boilers at the Okeelanta Cogeneration Plant located near the city of South Bay in western Palm Beach County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/4/00 to the person(s) listed:

Mr. Gus Cepero, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. Ricardo Lima, Okeelanta Corporation
Mr. David Dee, Landers & Parsons
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Charlotte J. Hayes 12/4/00
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Okeelanta Power Limited Partnership

Project No. 0990332-013-AC
Draft Permit PSD-FL-196L

Addition of Natural Gas to Biomass Boilers
Emissions Units 001 - 003

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to Okeelanta Power Limited Partnership to add natural as a supplemental fuel to the biomass boilers at the Okeelanta Cogeneration Plant located near the city of South Bay in western Palm Beach County. The applicant's authorized representative, Gus Cepero, may be contacted at Okeelanta Power Limited Partnership, P.O. Box 9, South Bay, FL 33493.

The addition of natural gas will increase the reliability and availability of the biomass boilers, which could subject this project to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. However, the biomass boilers have been determined to be "electric utility steam generating units". As such, the applicant has projected that future representative actual annual emissions will not trigger any PSD significant emissions rates as a result of this project. Therefore, the project is not subject to PSD at this time. However, the applicant is required to submit reports for five representative years of normal operations after completion of construction to ensure that the actual annual emissions do not exceed the PSD significant emissions rates as a result of this project. If the actual emissions do exceed the PSD significant emissions rates, the project is subject to PSD at that time and a determination of the Best Available Control Technology (BACT) must be determined for each significant pollutant in accordance with Rule 62-212.400, F.A.C.

The addition of natural gas is not expected to result in increased hourly emissions. However, applicable requirements of NSPS Subpart Da were included because natural gas becomes a new regulated fuel under this subpart. Because no increases in hourly or annual emissions are expected, no additional air quality analysis was required. The ambient air quality analysis performed for the original PSD permit application for the cogeneration plant indicated that emissions would not significantly contribute to, or cause a violation of, any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida, 32301 Telephone: 850/488-0114 Fax: 850/922-6979	Department of Environmental Protection Southwest District Office – Air Resources 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 Telephone: 813/744-6100 Fax: 813/744-6084	Palm Beach County Health Department EHE - Air Pollution Control Section P.O. Box 29 (901 Evernia Street) West Palm Beach, FL 33401-0029 Telephone: 561/355-3136 Fax: 561/355-2442

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's New Source Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

(DRAFT)

December 1, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Re: DEP File No. 0990332-013-AC (PSD-FL-196L)
Okeelanta Power L.P. - Cogeneration Plant
Request to Add Natural Gas as a Supplemental Fuel

Okeelanta Power L.P. operates a biomass cogeneration plant located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. Okeelanta Corporation operates a sugar mill and refinery at an adjacent location. For the purposes of the Department's Prevention of Significant Deterioration (PSD) and Title V operating permit programs, the two plants are considered to be a single facility. On June 20, 2000, Okeelanta Power L.P. applied to the Department for a modification of Permit No. PSD-FL-196 to add natural gas as a supplemental fuel to the biomass boilers to increase reliability and availability. The Department has reviewed the available information and approves the request as summarized in the attached Technical Evaluation. Original Permit No. PSD-FL-196 is hereby modified as follows.

Add the following specific permit condition:

29. Natural Gas Firing: The permittee is authorized to modify each biomass cogeneration boiler to add natural gas as a supplemental fuel in accordance with the following specific conditions.

    a. The total heat input from the new natural gas fired burners shall not exceed 605 mmBTU per hour for each boiler. The burners shall be a low-NOx design rated for no more than 0.15 pounds of NOx per mmBTU of heat input. The preliminary design indicates that a single burner will be installed in each upper corner of each boiler for a total of four burners, however this is subject to change.

    b. Natural gas may be fired alone or as a supplemental fuel in combination with other authorized fuels. In accordance with Specific Condition Nos. 15 and 20 of this permit, total fossil fuel firing (including natural gas) shall not exceed 25% of the heat input on a calendar quarter basis.

    c. The biomass boilers shall comply with each limit established in Specific Condition No. 20 when firing natural gas in combination with wood, bagasse, and/or distillate oil. For the brief periods when natural gas is fired alone, the biomass boilers shall comply with the lowest specified emission standards of any of the authorized fuels.

    d. Within 180 days of completion of construction, the permittee shall submit a report summarizing at least 30 days of operational data that includes gas firing. For each day of operation, the report shall summarize data collected from the continuous monitors for each biomass boiler for opacity, CO emissions, NOx emissions, and SO_2 emissions. It shall also include the average heat inputs from each fuel, the average power generation, and the hours of operation for each day.

    e. Before March 1st of each year, the permittee shall submit a report summarizing operations for the previous year in accordance with the following conditions.

        (1) The report shall calculate the actual annual emissions of CO, NOx, PM/PM_{10}, SO_2, and VOC in accordance with methodology provided in the letter application for this project and generally described as follows. Emissions of CO, NOx, and SO_2 shall be based on the sum of the daily averages computed by the continuous emissions monitoring systems and the heat inputs for each fuel type. Emissions of PM/PM_{10} and VOC shall

be calculated based on the required annual emissions performance tests conducted during the year and the heat inputs for each fuel type. The calculations and supporting data shall be provided for each biomass boiler. The permittee may use other methods approved in advance by the Department. {Permitting Note: Emissions of SO_2 were based on the preliminary CEMS data provided to the Department. The permittee may revise the SO_2 emissions estimate to be consistent with the revised CO and NOx CEMS data.}

(2). The report shall summarize emissions and compare the representative actual annual emissions to the past actual annual emissions for all three biomass boilers as indicated in the following table.

Operating Hours	Heat Input mmBTU/year	Annual Emissions, Tons Per Year				
		CO	NOx	PM/PM10	SO_2	VOC
Past Actual Emissions Prior to Project						
20,170	10,725,416	1526.07	753.56	172.50	169.98	44.20
Representative Actual Emissions for ______________ Calendar Year						
----	----					
PSD Significant Emission Rates (Table 212.400-2, F.A.C.)						
----	----	100	40	25/15	40	40
Future Actual Emissions, Above Which May Trigger PSD Review						
----	----	1626.0	793.5	197.5/187.5	209.9	84.2
Do the representative actual annual emissions trigger PSD review?						
----	----	Yes / No	Yes / No	Yes / No	Yes / No	Yes / No

As shown, the report shall indicate whether or not the project resulted in a PSD-significant emissions increase as defined in Table 212.400-2 of Chapter 62-212, F.A.C. The permittee shall utilize the "representative actual annual emissions" methodology, defined at Rule 62-210.200(12)(d), F.A.C., and the provisions of 40 CFR 52.21(b)(33), adopted by state rule, in its demonstration. The permittee may exclude any portion of the actual emissions after the change that could have been accommodated by the unit and that is unrelated to the particular change, including increased capacity utilization due to electricity demand growth for the utility system as a whole. However, the permittee shall identify and quantify the excluded emissions and present a justification for the exclusion.

(3) If the natural gas project results in a PSD-significant emissions increase, or if the permittee fails to submit the required information, the biomass boilers shall be subject to the requirements of PSD at that future time, which shall include a BACT determination for each PSD-significant pollutant.

(4) Reports shall be submitted to the Palm Beach County Health Department and the Department's New Source Review Section and South District Office. The reports shall be submitted for five separate years that are representative of normal post-change operations after completing construction of the natural gas burner systems. The five reports shall be submitted within the 10-year period following the completion of construction for the last biomass boiler. The reports shall start with the first full calendar year following the completion of construction of the final biomass boiler.

f. The permittee shall comply with the following NSPS Subpart Da requirements.

(1) When firing natural gas, SO_2 emissions shall be less than 0.20 lb/mmBTU of heat input. Compliance with this condition shall be demonstrated by obtaining a quarterly analysis of the sulfur content from the natural gas vendor and calculating the emission rate in terms of "pounds of SO_2 / mmBTU of heat input". {Permitting Note: The SO_2 emissions when firing pipeline-quality natural gas is estimated to be

approximately 0.05 lb/mmBTU based on 20 grains of sulfur per 100 SCF of natural gas. Pipeline-quality natural gas in Florida typically contains less than 1 grains per 100 SCF.}

(2) NOx emissions shall not exceed 0.15 lb/mmBTU of heat input from firing natural gas based on a 30-day rolling average . Because natural gas is being added as a supplemental fuel, compliance with this limit shall be demonstrated by the current continuous NOx emissions monitoring requirements of this permit. {Permitting Note: The current permit limit when firing biomass fuels and distillate oil is also 0.15 lb/mmBTU of heat input, as controlled by urea injection.}

[Design; Applicant Request; Permit No. PSD-FL-196; Rules 62-4.070(3), 62-210.200(12), 62-210.200(109), 62-212.300(1)(d), and 62-212.400, F.A.C.; 40 CFR 52.21(b)(33); 40 CFR 60, Subpart Da]

This permit modification is issued pursuant to Chapter 403, Florida Statutes. This modification shall supplement conditions imposed by previous permitting actions on Permit No. PSD-FL-196. Attached is original Permit No. PSD-FL-196 and a brief permitting history (Attachment A). A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, 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 must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ____________ to the person(s) listed:

Mr. Gus Cepero, Okeelanta Power L.P.*
Mr. James Meriwether, Okeelanta Power L.P.
Mr. Ricardo Lima, Okeelanta Corporation
Mr. David Dee, Landers & Parsons
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

(DRAFT)

______________ (Clerk) ______________ (Date)

TECHNICAL EVALUATION, PSD APPLICABILITY REVIEW, & PRELIMINARY DETERMINATION

Okeelanta Power Limited Partnership

ARMS Facility ID No. 0990332

Cogeneration Plant

Emissions Units 001 - 003

Project: Addition of Natural Gas as a Supplemental Fuel

Palm Beach County

Project No. 0990332-013-AC

Draft Permit No. PSD-FL-196L

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

November 30, 2000
(Revised 01/16/01)

{Filename: 196L TEPD.DOC}

This document describes the overall project, summarizes PSD applicability, and makes a preliminary determination. It is organized in the following sections:

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493
Authorized Representative:
Mr. Gus Cepero

1.2 Processing Schedule

06/20/00	Department received a request to add natural gas as a supplemental fuel.
07/14/00	Department requested additional information.
07/19/00	Department met with applicant in Tallahassee to discuss requested additional information.
09/18/00	Department received additional information.
10/10/00	Department requested additional information.
11/20/00	Department received additional information; application complete.

1.3 Facility Description and Location

Okeelanta Power Limited Partnership operates a cogeneration plant consisting of three biomass-fired steam boilers with electrical generators designed to produce up to a total of 74.9 MW of electrical power. The plant is located near the city of South Bay in western Palm Beach County, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The UTM coordinates are Zone 17, 524.1 km E, 2940.1 km N.

1.4 Standard Industrial Classification Code (SIC)

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

1.5 Regulatory Categories

HAPs: Based on available data, the facility is believed to be a major source of hazardous air pollutants (Title III).

Acid Rain: Based on the initial Title V application, the facility is not subject to the acid rain provisions of the Clean Air Act (Title IV).

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

PSD Major Source: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the industries listed as one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, each new project requires a PSD applicability review. Modifications resulting in actual emissions increases greater than the PSD Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. require a determination of Best Available Control Technology (BACT) for each significant increase.

NSPS Sources: The existing units remain subject to the New Source Performance Standards in 40 CFR 60 for the fossil fuel fired steam generating units (Subpart Da). The addition of natural gas, a fuel regulated by NSPS Subpart Da, will trigger additional minor requirements of this subpart.

2.0 PROPOSED PROJECT

The applicant, Okeelanta Power Limited Partnership, proposes to add natural gas as a supplemental fuel for each of the existing cogeneration boilers. The cogeneration boilers are currently permitted to fire up to a total of 11,500,000 mmBTU per year of wood materials, bagasse, and low sulfur distillate oil. Fossil fuel firing is limited to 25% of the total permitted heat input on a calendar quarter basis. Specifically, Okeelanta Power L.P. requests the ability to fire up to 605 mmBTU per hour of natural gas in each cogeneration boiler to achieve the maximum steam production rate. Okeelanta Power L.P. intends to use limited amounts of natural gas to enhance combustion of the primary biomass fuels and full natural gas firing to provide continued operation through infrequent interruptions of the biomass and ash handling systems. On an annual fuel balance basis, natural gas would displace distillate oil and then wood materials. The addition of natural gas is expected to reduce maintenance and increase reliability and availability of the units.

Note: As an aside, the initial PSD air construction permit authorized installation of coal handling facilities and the firing of low sulfur coal. However, the coal handling facilities were never constructed and coal has never been fired at this plant. Okeelanta Power L.P. must obtain new authorization from the Department (through a permit modification) to fire any coal in the future. At the very least, such a request shall evaluate current "Best Available Control Technologies" for each significant pollutant.

Based on operating experience, Okeelanta Power L.P. reports that the cogeneration boilers must reduce load or completely shutdown for 50-60 hours each year due to problems with the biomass fuel feed system and the ash removal system. Due to limited capacity, time constraints, and cost considerations, distillate oil has not been an effective response to such interruptions. Natural gas could provide both an effective operational and economical response during these infrequent periods to maintain steam and electrical production. The applicant believes that hourly and annual emissions will be reduced as a result of firing natural gas and that the project may represent a pollution control project.

Physically, the project involves installation of four low-NOx natural gas burners in each corner of each cogeneration boiler and the associated equipment including piping. The four burners will have a total heat input rate of 605 mmBTU per hour and a NOx emission rate of less than 0.15 lb/mmBTU. When firing natural gas, hourly emissions of carbon monoxide, particulate matter, sulfur dioxide, and volatile organic compounds are expected to decrease. Hourly emissions of nitrogen oxides for some gas burners *could* be expected to increase. However, each cogeneration boiler currently injects urea to control NOx emissions just below the permit limit of 0.15 lb/mmBTU. Therefore, hourly emissions of nitrogen oxides are not expected to increase either.

The applicant also claims that the biomass boilers are "electric utility steam generating units" as defined in Rule 62-2120.200(109), F.A.C. and should be able to project the "representative actual annual emissions" in accordance with Rule 62-210.200(12)(d), F.A.C. The applicant notes that the Department has made similar determinations for some waste-to-energy facilities.

3.0 EMISSIONS

Pipeline-quality natural gas contains only trace amounts of ash, sulfur, and other contaminants. The Department compared short term emissions from natural gas combustion to actual and allowable emissions from the biomass boilers. The results are summarized in the following Table 3.0a. It appears that firing natural gas in the cogeneration boilers should not result in hourly emission increases for any regulated pollutant including carbon monoxide, lead, mercury, nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, or volatile organic compounds. Hourly emission rates are discussed further in Section 5.0 with regard to NSPS applicability.

Table 3.0a Summary of Short Term Emission Factors

Pollutant	Emission Factor, lb/mmBTU		
	Natural Gas [1]	Past Actual	Permit Limit [3]
CO [2]	0.08	0.29	0.35
Hg	2.5 E^{-07}	-------	54.3 E^{-07}, Bagasse 40.0 E^{-07}, Wood 24.0 E^{-07}, Oil
NOx [2]	0.14	0.14	0.15
Pb	4.8 E^{-07}	-------	250.0 E^{-07}, Bagasse 16,000.0 E^{-07}, Wood 8.9 E^{-07}, Oil
PM	7.3 E^{-03}	-------	30.0 E^{-03}
SAM	8.7 E^{-05}	-------	300.0 E^{-05}, Biomass 150.0 E^{-05}, Oil
SO_2 [2]	5.8 E^{-04}	320 E^{-04}	1000 E^{-04}, Biomass 500.0 E^{-04}, Oil
VOC [2]	5.3 E^{-03}	8.2 E^{-03}	60.0 E^{-03}

1 Based on AP-42, Section 1.4, "Natural Gas Combustion, External Combustion Sources".

2 Past actual emissions based on CEMS data for CO, NOx, and SO_2 and emissions performance tests for VOC.

3 Limits in Permit No. PSD-FL-196; biomass/oil.

Annual emissions could increase as a result of this project due to increased reliability and availability of the cogeneration boilers. However, the cogeneration plant has operated at nearly 94% of the permitted heat input rate over the last 18 months of continuous operation. So, any increase in annual emissions resulting from increased utilization of the cogeneration boilers would be almost negligible for all of the pollutants except carbon monoxide, nitrogen oxides, and volatile organic compounds. Therefore, to simplify the review, only annual emissions of CO, NOx, and VOC will be reviewed in detail.

This project would clearly trigger PSD for CO, NOx, and VOC if the future potential emissions were compared to past actual emissions because the units are operating well below the permitted levels. However, the addition of natural gas as a supplemental fuel, in isolation from other unrelated causes, is not likely to generate such levels of annual emissions increases. For this project, annual emissions increases would more likely result from the increased reliability and availability of the units. For purposes of demonstrating the possible impacts related to the increased availability, the Department estimated emissions increases based on the full permitted heat input and assuming that average emissions rates remained constant. The results are provided in the following Table 3.0b. As shown, it is estimated that the proposed project could trigger PSD for CO and NOx emissions simply due to increased availability. It is unlikely that the project would trigger PSD for PM, SO_2, or VOC emissions due to increased availability.

Table 3.0b Summary of Past Actual and Estimated Future Potential Emissions

Boiler	Operating Hours	Heat Input mmBTU/year	Annual Emissions, Tons Per Year				
			CO [1]	NOx [1]	PM/PM10 [2]	SO2 [1]	VOC [2]
Actual Operating Data for the Period of April 1999 through March 2000							
A	7265	3,824,398	478.34	272.22	395.6	47.11	12.1
B	5927	3,206,304	485.29	220.20	161.2	38.32	19.6
C	6978	3,694,714	562.44	261.14	560.0	47.80	12.5
Total	20,170	10,725,416	1526.07	753.56	1116.8	133.23	44.2
Limits in Permit No. PSD-FL-196							
----	8760 per unit	11,500,000	2012.5	862.5	172.5	287.5 [4]	345.0
PSD Significant Emission Rates							
----	----	----	100	40	25/15	40	40
Estimated Emissions Increases [3]							
----	----	----	110.2	54.4	0.0 [2]	9.62	3.2
Will Increased Availability Trigger PSD?			Yes	Yes	No	No	No

[1] Based on actual CEMS data for CO, NOx, and SO_2 emissions.

[2] Based on annual stack test data and annual heat input rates for PM and VOC emissions. The plant is under a Consent Order for exceeding the PM limits. Mechanical dust collectors have been added to remove large PM to make the ESPs more efficient. PM is not expected to increase as a result of this project.

[3] For demonstration purposes only, emissions increases due to the increased availability (774,584 mmBTU/year) were estimated assuming the past actual average emission rates remained constant.

[4] Maximum annual SO_2 emissions without coal firing.

4.0 PSD APPLICABILITY REVIEW

4.1 PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant.

Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

4.2 Available Information

In addition to the information submitted by the applicant, the Department also relied on the following information to make its determination:

- Definition of actual emissions in Rule 62-210.200(12), F.A.C.;
- Definition of electric utility steam generating unit in Rules 62-210.200(109), F.A.C.;
- Definition of representative actual annual emissions in 40 CFR 52.21(b)(33);
- Comments received from the Palm Beach County Health Department regarding a comparison of the past actual to future potential annual emissions and the potential applicability of NSPS Subpart Da;
- Pollution control project for the Hillsborough County Solid Waste Energy Facility, PSD-FL-121B; and
- Pinellas County Resource Recovery Facility's Capital Replacement Project (Project No. 1030117-003-AC, Permit Nos. PSD-FL-011B & PSD-FL-098B)

4.3 PSD Applicability for Proposed Project

The stated purpose of this project is to increase reliability and availability of the cogeneration boilers as well as reduce maintenance. Therefore, the Department determines that the addition of natural gas is not a pollution control project because the primary purpose is not to reduce air pollution. Therefore, the project is not exempt from PSD on this basis.

The applicant also contends that the biomass boilers are "electric utility steam generating units" in accordance with Rules 62-210.200 (12) and (109), F.A.C. See Attachment A for the complete text of these rules. In short, a qualifying unit is a steam generating unit that was constructed for the purpose of:

- Supplying more than one-third of its potential electric output capacity, and
- Supplying more than 25 MW electrical output to any utility power distribution system for sale.

The biomass boilers were constructed to provide steam to the adjacent sugar mill and to produce electrical energy for sale to the power distribution system. The economic feasibility of the project relied entirely on the sale of electrical power. The cogeneration biomass boilers support a single steam-electrical generator designed for a maximum electrical production capacity 74.9 MW. During the off-season for sugarcane processing (typically October through April), the plant supplies all of its potential electric output capacity to the power distribution system. It appears that the cogeneration plant meets the definition of an electric utility steam generating unit. For a more detailed analysis of a similar applicability review for electric utility steam generating units, see the Pinellas County Resource Recovery Facility's Capital Replacement Project (Project No. 1030117-003-AC, Permit Nos. PSD-FL-011B & PSD-FL-098B).

Qualifying as an electric utility steam generating unit is significant because Rule 62-210.200(12)(d), F.A.C. allows such units to project "representative actual annual emissions" (defined in 40 CFR 52.21(b)(33)) in order to determine the net emissions increases after the change. Again, see Attachment A for complete text of these rules. Representative actual annual emissions are defined as actual annual emissions of the unit following a physical or operational change representative of normal post-change operations of the unit. The owner or operator must maintain and annually report information demonstrating that the physical or operational change did not result in a PSD-significant actual emissions increase. The reports must be submitted for five separate years that are representative of normal post-change operations of the unit, but within at least 10 years following the change. The Department must consider the effect any such change will have on increasing or decreasing the hourly emissions rate and on the projected capacity utilization. However, the Department must also exclude any portion of the actual emissions after the change that could have been accommodated by the unit and that is unrelated to the particular change, including increased capacity utilization due to electricity demand growth for the utility system as a whole.

Okeelanta Power L.P. projects that the cogeneration plant is operating near maximum capacity and the addition of natural gas will not cause an emission increases in excess of the PSD Significant Emissions Rates. The following table summarizes the projections of the future representative actual annual emissions after the addition of natural gas as a supplemental fuel.

Table 4.3a Projected Future Representative Annual Emissions

Actual Operating Data for the Period of April 1999 through March 2000							
All Boilers	Operating Hours	Heat Input mmBTU/year	Annual Emissions, Tons Per Year				
			CO [1]	NOx [1]	PM/PM_{10} [2]	SO_2	VOC [2]
Total	20,170	10,725,416	1526.07	753.56	172.50	133.23	44.20
Limits in Permit No. PSD-FL-196							
----	8760 per unit	11,500,000	2012.5	862.5	172.5	287.5 [3]	345.0
PSD Significant Emission Rates							
----	----	----	100	40	25/15	40	40
Future Actual Emissions, Above Which May Trigger PSD Review							
----	----	----	1626.0	793.5	172.5	173.2	84.2

1 Based on actual CEMS data for CO, NOx, and SO_2 emissions.

2 Based on annual stack test data and annual heat input rate. PM/PM_{10} emissions based on the permit limit due to the compliance issues.

3 Maximum annual SO_2 emissions without coal firing.

As shown in this table, the net emissions increases are predicted to be below the PSD Significant Emissions Rates for each pollutant. The Department's previous estimates of the actual emissions in Table 3.0b indicates:

- Based on past actual emission rates, CO, PM/PM_{10}, SO_2, and VOC emissions are unlikely to trigger the PSD significant emission's rates even if the full permitted capacity is realized.
- If the full permitted capacity is realized, NOx emissions could trigger the PSD significant emission rate. However, the biomass boilers have NOx continuous emission monitors and NOx emissions are controlled by the injection of urea (SNCR). The operator can readily track and adjust NOx emissions accordingly.
- The cogeneration plant has been operated at 94% of permitted capacity during the last 18 months. Little opportunity exists to increase availability to the full permitted heat input limit.

The Department determines that the applicant's emissions projections are reasonable. Based on the comparison of past actual annual emissions to representative future actual annual emissions, PSD does not apply to this project at this time. However, Okeelanta Power L.P. must provide reports as stated above for five separate years that are representative of normal post-change operations of the unit. If the reports indicate a PSD-significant emissions increase as a result of the addition of natural gas, the project will be subject to PSD at that time as if the project had never been constructed.

5.0 NSPS APPLICABILITY

Based on general information available for new natural gas-fired burners, this project is not expected to result in an increase in emissions of carbon monoxide, lead, mercury, particulate matter, sulfur dioxide, sulfuric acid mist, or volatile organic compounds. Emissions of nitrogen oxides *could* increase depending on the burner model selected. Low-NOx burners are available that can achieve the permitted NOx rate of 0.15 lb/mmBTU. In addition, the existing NOx control system could compensate by increasing the urea injection rate. However, natural gas is an NSPS-regulated fuel that was not previously fired. Therefore, the Department notes the following new applicable NSPS Subpart Da requirements.

- Regulation 40 CFR 60.43a allows for no SO_2 reduction when firing a gaseous fuel as long as the SO_2 emissions are less than 0.20 lb/mmBTU of heat input. The Department estimates an SO_2 emission rate for firing natural gas of 0.05 lb/mmBTU based on 20 grains of sulfur per 100 SCF of natural gas. Pipeline-quality natural gas in Florida typically contains less than 1 grains per 100 SCF.
- Regulation 60.43a. (d)(2) limits NOx emissions to 0.15 lb/mmBTU of heat input or less from a gaseous fuel, based on a 30-day rolling average (for any affected facility modified or reconstructed after July 9, 1997). The Department notes that this is the current NOx emissions limit for each biomass boiler. Low-NOx burners firing natural gas and the urea injection system are capable of achieving this limit.

6.0 AIR QUALITY ANALYSIS

The proposed project will not result in an increase in any of the maximum hourly or annual emissions rates that were used to develop the original Air Quality Analysis, which was part of the initial PSD permit application. It is not expected that this project will change any of the previously modeled ambient impacts or conditions. Therefore, no additional air dispersion modeling was necessary.

7.0 PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the available information, reasonable assurances provided by the applicant, previous determinations for similar projects, and the conditions specified in the Draft Permit. The Department notes that the determinations and conclusions made in this evaluation are specific to this project and do not establish any precedents for the sugar industry, related industries, or electric utility steam generating units in general. These determinations must be made on a case-by-case basis considering each unique set of circumstances. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

ATTACHMENT A – APPLICABLE RULES

Rule 62-210.200, F.A.C.

(12) "Actual Emissions" - The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:

(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.

(c) For any emissions unit (other than an electric utility steam generating unit specified in subparagraph (d) of this definition) which has not begun normal operations on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date.

(d) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the owner or operator maintains and submits to the Department on an annual basis, for a period of 5 years representative of normal post-change operations of the unit, within the period not longer than 10 years following the change, information demonstrating that the physical or operational change did not result in an emissions increase. The definition of "representative actual annual emissions" found in 40 CFR 52.21(b)(33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(109) "Electric utility steam generating unit" - Any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the unit.

40 CFR 52.21 Prevention of Significant Air Quality

(b) Definitions

(33) Representative actual emissions means the average emission rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on the projected capacity utilization. In projecting future emissions the Administrator shall:

(i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(ii) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

TECHNICAL EVALUATION, PSD APPLICABILITY REVIEW, & PRELIMINARY DETERMINATION

Okeelanta Power Limited Partnership

ARMS Facility ID No. 0990332

Cogeneration Plant

Emissions Units 001 - 003

Project: Addition of Natural Gas as a Supplemental Fuel

Palm Beach County

Project No. 0990332-013-AC

Draft Permit No. PSD-FL-196L

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

November 30, 2000

{Filename: 196L TEPD.DOC}

Corrections made on 01/16/01
Revised Document

This document describes the overall project, summarizes PSD applicability, and makes a preliminary determination. It is organized in the following sections:

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493
Authorized Representative:
Mr. Gus Cepero

1.2 Processing Schedule

06/20/00	Department received a request to add natural gas as a supplemental fuel.
07/14/00	Department requested additional information.
07/19/00	Department met with applicant in Tallahassee to discuss requested additional information.
09/18/00	Department received additional information.
10/10/00	Department requested additional information.
11/20/00	Department received additional information; application complete.

1.3 Facility Description and Location

Okeelanta Power Limited Partnership operates a cogeneration plant consisting of three biomass-fired steam boilers with electrical generators designed to produce up to a total of 74.9 MW of electrical power. The plant is located near the city of South Bay in western Palm Beach County, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The UTM coordinates are Zone 17, 524.1 km E, 2940.1 km N.

1.4 Standard Industrial Classification Code (SIC)

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

1.5 Regulatory Categories

HAPs: Based on available data, the facility is believed to be a major source of hazardous air pollutants (Title III).

Acid Rain: Based on the initial Title V application, the facility is not subject to the acid rain provisions of the Clean Air Act (Title IV).

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PSD Major Source: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the industries listed as one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, each new project requires a PSD applicability review. Modifications resulting in actual emissions increases greater than the PSD Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. require a determination of Best Available Control Technology (BACT) for each significant increase.

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> *Note: As an aside, the initial PSD air construction permit authorized installation of coal handling facilities and the firing of low sulfur coal. However, the coal handling facilities were never constructed and coal has never been fired at this plant. Okeelanta Power L.P. must obtain new authorization from the Department (through a permit modification) to fire any coal in the future. At the very least, such a request shall evaluate current "Best Available Control Technologies" for each significant pollutant.*

Based on operating experience, Okeelanta Power L.P. reports that the cogeneration boilers must reduce load or completely shutdown for 50-60 hours each year due to problems with the biomass fuel feed system and the ash removal system. Due to limited capacity, time constraints, and cost considerations, distillate oil has not been an effective response to such interruptions. Natural gas could provide both an effective operational and economical response during these infrequent periods to maintain steam and electrical production. The applicant believes that hourly and annual emissions will be reduced as a result of firing natural gas and that the project may represent a pollution control project.

Physically, the project involves installation of four low-NOx natural gas burners in each upper corner of each cogeneration boiler and the associated equipment including piping. The four burners will have a total heat input rate of 605 mmBTU per hour and a NOx emission rate of less than 0.15 lb/mmBTU. When firing natural gas, hourly emissions of carbon monoxide, particulate matter, sulfur dioxide, and volatile organic compounds are expected to decrease. Hourly emissions of nitrogen oxides for some gas burners *could* be expected to increase. However, each cogeneration boiler currently injects urea to control NOx emissions just below the permit limit of 0.15 lb/mmBTU. Therefore, hourly emissions of nitrogen oxides are not expected to increase either.

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3.0 EMISSIONS

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NOx [2]	0.14	0.14	0.15
Pb	4.8 E^{-07}	-------	250.0 E^{-07}, Bagasse 16,000.0 E^{-04}, Wood 8.9 E^{-07}, Oil
PM	7.3 E^{-03}	-------	30.0 E^{-03}
SAM	8.7 E^{-05}	-------	300.0 E^{-05}, Biomass 150.0 E^{-05}, Oil
SO_2 [2]	5.8 E^{-04}	320 E^{-04}	1000 E^{-04}, Biomass 500.0 E^{-04}, Oil
VOC [2]	5.3 E^{-03}	8.2 E^{-03}	60.0 E^{-03}

1 Based on AP-42, Section 1.4, "Natural Gas Combustion, External Combustion Sources".

2 Past actual emissions based on CEMS data for CO, NOx, and SO_2 and emissions performance tests for VOC.

3 Limits in Permit No. PSD-FL-196; biomass/oil.

Annual emissions could increase as a result of this project due to increased reliability and availability of the cogeneration boilers. However, the cogeneration plant has operated at nearly 94% of the permitted heat input rate over the last 18 months of continuous operation. So, any increase in annual emissions resulting from increased utilization of the cogeneration boilers would be almost negligible for all of the pollutants except carbon monoxide, nitrogen oxides, and volatile organic compounds. Therefore, to simplify the review, only annual emissions of CO, NOx, and VOC will be reviewed in detail.

This project would clearly trigger PSD for CO, NOx, and VOC if the future potential emissions were compared to past actual emissions because the units are operating well below the permitted levels. However, the addition of natural gas as a supplemental fuel, in isolation from other unrelated causes, is not likely to generate such levels of annual emissions increases. For this project, annual emissions increases would more likely result from the increased reliability and availability of the units. For purposes of demonstrating the possible impacts related to the increased availability, the Department estimated emissions increases based on the full permitted heat input and assuming that average emissions rates remained constant. The results are provided in the following Table 3.0b. As shown, it is estimated that the proposed project could trigger PSD for CO and NOx emissions simply due to increased availability. It is unlikely that the project would trigger PSD for PM, SO_2, or VOC emissions due to increased availability.

Table 3.0b Summary of Past Actual and Estimated Future Potential Emissions

Actual Operating Data for the Period of April 1999 through March 2000							
Boiler	Operating Hours	Heat Input mmBTU/year	Annual Emissions, Tons Per Year				
			CO [1]	NOx [1]	PM/PM10 [2]	SO_2 [1]	VOC [2]
A	7265	3,824,398	478.34	272.22	395.6	53.54	12.1
B	5927	3,206,304	485.29	220.20	161.2	48.09	19.6
C	6978	3,694,714	562.44	261.14	560.0	68.35	12.5
Total	20,170	10,725,416	1526.07	753.56	1116.8	169.98	44.2
Limits in Permit No. PSD-FL-196							
----	8760 per unit	11,500,000	2012.5	862.5	172.5	287.5 [4]	345.0
PSD Significant Emission Rates							
----	----	----	100	40	25/15	40	40
Estimated Emissions Increases [3]							
----	----	----	110.2	62.3	12.46	12.28	3.2
Will Increased Availability Trigger PSD?			Yes	Yes	No	No	No

1 Based on actual CEMS data for CO, NOx, and SO_2 emissions.

2 Based on annual stack test data and annual heat input rates for PM and VOC emissions. The plant is under a Consent Order for exceeding the PM limits. Mechanical dust collectors have been added to remove large PM to make the ESPs more efficient. The estimated emissions increase is based on the permit limit.

3 For demonstration purposes only, emissions increases due to the increased availability (774,584 mmBTU/year) were estimated assuming the past actual average emission rates remained constant.

4 Maximum annual SO_2 emissions without coal firing.

4.0 PSD APPLICABILITY REVIEW

4.1 PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant.

Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

4.2 Available Information

In addition to the information submitted by the applicant, the Department also relied on the following information to make its determination:

- Definition of actual emissions in Rule 62-210.200(12), F.A.C.;
- Definition of electric utility steam generating unit in Rules 62-210.200(109), F.A.C.;
- Definition of representative actual annual emissions in 40 CFR 52.21(b)(33);
- Comments received from the Palm Beach County Health Department regarding a comparison of the past actual to future potential annual emissions and the potential applicability of NSPS Subpart Da;
- Pollution control project for the Hillsborough County Solid Waste Energy Facility, PSD-FL-121B; and
- Pinellas County Resource Recovery Facility's Capital Replacement Project (Project No. 1030117-003-AC, Permit Nos. PSD-FL-011B & PSD-FL-098B)

4.3 PSD Applicability for Proposed Project

The stated purpose of this project is to increase reliability and availability of the cogeneration boilers as well as reduce maintenance. Therefore, the Department determines that the addition of natural gas is not a pollution control project because the primary purpose is not to reduce air pollution. Therefore, the project is not exempt from PSD on this basis.

The applicant also contends that the biomass boilers are "electric utility steam generating units" in accordance with Rules 62-210.200 (12) and (109), F.A.C. See Attachment A for the complete text of these rules. In short, a qualifying unit is a steam generating unit that was constructed for the purpose of:

- Supplying more than one-third of its potential electric output capacity, and
- Supplying more than 25 MW electrical output to any utility power distribution system for sale.

The biomass boilers were constructed to provide steam to the adjacent sugar mill and to produce electrical energy for sale to the power distribution system. The economic feasibility of the project relied entirely on the sale of electrical power. The cogeneration biomass boilers support a single steam-electrical generator designed for a maximum electrical production capacity 74.9 MW. During the off-season for sugarcane processing (typically October through April), the plant supplies all of its potential electric output capacity to the power distribution system. It appears that the cogeneration plant meets the definition of an electric utility steam generating unit. For a more detailed analysis of a similar applicability review for electric utility steam generating units, see the Pinellas County Resource Recovery Facility's Capital Replacement Project (Project No. 1030117-003-AC. Permit Nos. PSD-FL-011B & PSD-FL-098B).

Qualifying as an electric utility steam generating unit is significant because Rule 62-210.200(12)(d), F.A.C. allows such units to project "representative actual annual emissions" (defined in 40 CFR 52.21(b)(33)) in order to determine the net emissions increases after the change. Again, see Attachment A for complete text of these rules. Representative actual annual emissions are defined as actual annual emissions of the unit following a physical or operational change representative of normal post-change operations of the unit. The owner or operator must maintain and annually report information demonstrating that the physical or operational change did not result in a PSD-significant actual emissions increase. The reports must be submitted for five separate years that are representative of normal post-change operations of the unit, but within at least 10 years following the change. The Department must consider the effect any such change will have on increasing or decreasing the hourly emissions rate and on the projected capacity utilization. However, the Department must also exclude any portion of the actual emissions after the change that could have been accommodated by the unit and that is unrelated to the particular change, including increased capacity utilization due to electricity demand growth for the utility system as a whole.

Okeelanta Power L.P. projects that the cogeneration plant is operating near maximum capacity and the addition of natural gas will not cause an emission increases in excess of the PSD Significant Emissions Rates. The following table summarizes the projections of the future representative actual annual emissions after the addition of natural gas as a supplemental fuel.

Table 4.3a Projected Future Representative Annual Emissions

Actual Operating Data for the Period of April 1999 through March 2000							
All Boilers	Operating Hours	Heat Input mmBTU/year	Annual Emissions, Tons Per Year				
			CO[1]	NOx[1]	PM/PM10	SO2	VOC[2]
Total	20,170	10,725,416	1526.07	753.56	172.50	169.98	44.20
Limits in Permit No. PSD-FL-196							
----	8760 per unit	11,500,000	2012.5	862.5	172.5	287.5 [3]	345.0
PSD Significant Emission Rates							
----	----	----	100	40	25/15	40	40
Future Actual Emissions, Above Which May Trigger PSD Review							
----	----	----	1626.0	793.5	197.5/187.5	209.9	84.2

1 Based on actual CEMS data for CO, NOx, and SO_2 emissions.

2 Based on annual stack test data and annual heat input rate VOC emissions. Based on the permit limit for PM/PM_{10} emissions due to the Consent Order.

3 Maximum annual SO_2 emissions without coal firing.

As shown in this table, the net emissions increases are predicted to be below the PSD Significant Emissions Rates for each pollutant. The Department's previous estimates of the actual emissions in Table 3.0b indicates:

- Based on past actual emission rates, CO, PM/PM_{10}, SO_2, and VOC emissions are unlikely to trigger the PSD significant emissions rates even if the full permitted capacity is realized
- If the full permitted capacity is realized, NOx emissions could trigger the PSD significant emission rate. However, the biomass boilers have NOx continuous emission monitors and NOx emissions are controlled by the injection of urea (SNCR). The operator can readily track and adjust NOx emissions accordingly.
- The cogeneration plant has been operated at 94% of permitted capacity during the last 18 months. Little opportunity exists to increase availability to the full permitted heat input limit.

The Department determines that the applicant's emissions projections are reasonable. Based on the comparison of past actual annual emissions to representative future actual annual emissions, PSD does not apply to this project at this time. However, Okeelanta Power L.P. must provide reports as stated above for five separate years that are representative of normal post-change operations of the unit. If the reports indicate a PSD-significant emissions increase as a result of the addition of natural gas, the project will be subject to PSD at that time as if the project had never been constructed.

5.0 NSPS APPLICABILITY

Based on general information available for new natural gas-fired burners, this project is not expected to result in an increase in emissions of carbon monoxide, lead, mercury, particulate matter, sulfur dioxide, sulfuric acid mist, or volatile organic compounds. Emissions of nitrogen oxides *could* increase depending on the burner model selected. Low-NOx burners are available that can achieve the permitted NOx rate of 0.15 lb/mmBTU. In addition, the existing NOx control system could compensate by increasing the urea injection rate. However, natural gas is an NSPS-regulated fuel that was not previously fired. Therefore, the Department notes the following new applicable NSPS Subpart Da requirements.

- Regulation 40 CFR 60.43a allows for no SO_2 reduction when firing a gaseous fuel as long as the SO_2 emissions are less than 0.20 lb/mmBTU of heat input. The Department estimates an SO_2 emission rate for firing natural gas of 0.05 lb/mmBTU based on 20 grains of sulfur per 100 SCF of natural gas. Pipeline-quality natural gas in Florida typically contains less than 1 grains per 100 SCF.
- Regulation 60.43a. (d)(2) limits NOx emissions to 0.15 lb/mmBTU of heat input or less from a gaseous fuel, based on a 30-day rolling average (for any affected facility modified or reconstructed after July 9, 1997). The Department notes that this is the current NOx emissions limit for each biomass boiler. Low-NOx burners firing natural gas and the urea injection system are capable of achieving this limit.

6.0 AIR QUALITY ANALYSIS

The proposed project will not result in an increase in any of the maximum hourly or annual emissions rates that were used to develop the original Air Quality Analysis, which was part of the initial PSD permit application. It is not expected that this project will change any of the previously modeled ambient impacts or conditions. Therefore, no additional air dispersion modeling was necessary.

7.0 PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the available information, reasonable assurances provided by the applicant, previous determinations for similar projects, and the conditions specified in the Draft Permit. The Department notes that the determinations and conclusions made in this evaluation are specific to this project and do not establish any precedents for the sugar industry, related industries, or electric utility steam generating units in general. These determinations must be made on a case-by-case basis considering each unique set of circumstances. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

ATTACHMENT A – APPLICABLE RULES

Rule 62-210.200, F.A.C.

(12) "Actual Emissions" - The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:

(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.

(c) For any emissions unit (other than an electric utility steam generating unit specified in subparagraph (d) of this definition) which has not begun normal operations on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date.

(d) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the owner or operator maintains and submits to the Department on an annual basis, for a period of 5 years representative of normal post-change operations of the unit, within the period not longer than 10 years following the change, information demonstrating that the physical or operational change did not result in an emissions increase. The definition of "representative actual annual emissions" found in 40 CFR 52.21(b)(33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(109) "Electric utility steam generating unit" - Any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the unit.

40 CFR 52.21 Prevention of Significant Air Quality

(b) Definitions

(33) Representative actual emissions means the average emission rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on the projected capacity utilization. In projecting future emissions the Administrator shall:

(i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(ii) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

ATTACHMENT A - PERMITTING HISTORY (12/00)

Air Permit No. PSD-FL-196: Department issued original PSD permit on 09/27/93.

Project No. 0990332-001-AC (PSD-FL-196A): OkPLP requested a limit on yard trash of 30% by weight to avoid most of the applicable requirements of 40 CFR 60, Subpart Ea. Department issued modification on 02/20/96, which added specific condition 12A.

Project No. 0990332-002-AC (PSD-FL-196B): OkPLP requested an extension of time for the simultaneous operation of the cogeneration boilers with the sugar mill boilers in order to perfect the steam interconnection. Department issued modification on 06/14/96. Specific condition nos. 17 and 18 were revised to extend simultaneous operation beyond the first year of commercial startup of the cogeneration boilers to April 1, 1997. The permit required the sugar mill boilers to be rendered incapable of operation no later than January 1, 1999.

Project No. 0990332-003-AC (PSD-FL-196C): OkPLP requested approval to fire tire derived fuel. Department issued modification on 01/22/97 to allow for a demonstration period to collect emissions data.

Project No. 0990332-004-AC (PSD-FL-196D): OkPLP requested a revision to the emission standard and testing requirements for sulfuric acid mist. Department issued modification on 04/18/97, which retained the emission standard, but revised the test method to 8 (modified).

Project No. 0990332-005-AC (PSD-FL-196E): OkPLP requested an extension of time for the simultaneous operation of the cogeneration boilers with the sugar mill boilers in order to perfect the steam interconnection. Department issued modification on 04/05/97. Specific condition nos. 17 and 18 were revised to extend simultaneous operation to April 1, 1998. The permit required the sugar mill boilers to be rendered incapable of operation no later than January 1, 1999.

Project No. 0990332-006-AC (PSD-FL-196F): OkPLP requested a modification of the emissions standards for carbon monoxide, lead, and mercury. Department issued modification on 10/24/97.

Project No. 0990332-007-AC (PSD-FL-196G): OkPLP requested amendment to specific condition #11 to clarify the performance test schedule. Department issued modification on 05/08/97.

Project No. 0990332-008-AC (PSD-FL-196H): OkPLP requested a revision to the 24-hour rolling average for determining peak electrical generation. Application was withdrawn on 02/03/97.

Project No. 0990332-009-AC (PSD-FL-196I): OkPLP requested an extension of time for the simultaneous operation of the cogeneration boilers with the sugar mill boilers in order to provide additional time to ensure that the interconnections (bagasse fuel and steam systems) were commercially and operationally reliable. Department issued modification on 06/16/98. Specific condition nos. 17 and 18 were revised to extend simultaneous operation to April 1, 2000. The permit required the sugar mill boilers to be rendered incapable of operation no later than April 1, 2001.

Project No. 0990332-010-AC (PSD-FL-196J): OkPLP requested a revision to the CO emissions standard. Department issued modification of the CO averaging period on 06/24/99.

Project No. 0990332-011-AC (PSD-FL-196K): OkPLP requested a modification to extend operation of Okeelanta Corporation's sugar mill boilers as standby units for the cogeneration boilers due to litigation with FPL. Department issued modification on 11/06/00.

Project No. 0990332-012-AC: OkPLP requested approval to install particulate dust collectors prior to the electrostatic precipitators. Department issued approval letter on 12/22/99. Approval incorporated into modification PSD-FL-196K.

Project No. 0990332-012-AC (PSD-FL-196L): OkPLP requested to add natural gas as a supplemental fuel to the biomass boilers. This is the pending project.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC50-219413
PSD-FL-196
Palm Beach County

Mr. Gus Cepero, Vice President
Okeelanta Power Limited Partnership
P. O. Box 86
South Bay, Florida 33493
_____________________________________/

Enclosed is construction Permit Number AC50-219413 (PSD-FL-196) for a 74.9 megawatt (MW) electric cogeneration facility to be constructed at the Okeelanta Corporation sugar mill located 6 miles south of South Bay, off U.S. Highway 27 in Palm Beach County, Florida. This permit is issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit 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 in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; 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 Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on Sept 24, 1993 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 9-27-93 (Date)

Copies furnished to:
- David Knowles, SD
- Isidore Goldman, SED
- James Stormer, PBCHD
- Jewell Harper, EPA
- John Bunyak, NPS
- David Buff, KBN

Final Determination

Okeelanta Power Limited Partnership
South Bay, Palm Beach County, Florida

74.9 Megawatt (MW) Electric Cogeneration Facility

Permit No.: AC 50-219413
PSD-FL-196

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

September 17, 1993

FINAL DETERMINATION

The Technical Evaluation and Preliminary Determination for a permit to construct (AC 50-219413/PSD-FL-196) a 71.25 megawatt (MW) electric cogeneration facility for Okeelanta Power Limited Partnership, P.O. Box 86, South Bay, Florida 33493, was distributed on June 3, 1993. The cogeneration facility will be built at Okeelanta Corporation's sugar mill located 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The Notice of Intent to Issue was published in the Palm Beach Post on June 9, 1993. Copies of the evaluation were available for public inspection at the Department offices in Tallahassee, Ft. Myers, and West Palm Beach, and at the Palm Beach County Health Department office in West Palm Beach.

The Environmental Protection Agency and National Park Service had no negative comments on the proposed permit.

In letters dated July 2 and August 11, 1993, the applicant requested that the plant be allowed to generate 74.9 megawatts (MW) of electricity as proposed in the application, that they be allowed to burn small quantities of treated wood that may escape detection by their inspection program provided the air pollution standards are not exceeded, that the prohibition on the burning of "special waste" be deleted from the permit, that they not be required to analyze the ash, that the permit be reworded to state that the fossil fuel heat input to the boilers will be less than 25 percent on a quarterly basis instead of 25 percent on an annual basis, that the nitrogen oxide emissions be corrected from 873.1 to 862.5 tons per year (TPY), that a 3-hour sulfur dioxide emission limit for coal be added to the permit, that a visible emission standard be added to the permit, that they not be required to test the emissions from all allowed fuels during the first 180 days of operation, that they be allowed to use other test methods than the ones listed in the permit, that they be allowed more than 2 hours for excess emissions during startup conditions, and that they not be required to cover the inactive coal storage pile. Except for the request to not cover the inactive coal pile or analyze the ash, the Department finds their comments acceptable and have made the following changes, along with minor editioral changes to the proposed permit:

Specific conditions Nos. 1, 11, and 15, the project description, and the BACT and RACT determinations were revised from 71.25 to 74.9 MW, 1-hour average, except during emission compliance and equipment performance tests. This change does not increase allowable heat input or emissions of any air pollutant.

Specific condition No. 12 was revised to incorporate a plan to minimize treated/painted wood from being burned in the cogeneration facility. Limits on metals associated with treated wood needed to prevent the Acceptable Ambient Concentration from being exceeded were added to the permit.

Specific Condition No. 17 was revised to allow limited operation of both existing bagasse boilers and new cogeneration boilers during the first year while the cogeneration facility is being debugged.

Specific condition No. 18 was revised to allow additional time for excess emissions during startup. Limits on the number of startups during a time period were added to the permit.

Specific condition No. 20 was revised to include a visible emission standard and a 3-hour sulfur dioxide standard for coal based on the new source performance standard for electrical utility steam generating units.

Specific condition No. 21 was revised to allow the use of additional EPA approved compliance test methods.

Specific condition No. 23 was corrected to require a 15 day notice instead of 10 days as listed in the proposed permit prior to any scheduled compliance test.

The final action of the Department will be to issue construction permit No. AC 50-219413 (PSD-FL-196) as proposed in the Technical Evaluation and Preliminary Determination except for the changes noted above.

Florida Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Okeelanta Power Limited
Partnership
P. O. Box 86
South Bay, FL 33493

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996
County: Palm Beach
Latitude/Longitude: 26°35'00"N
80°45'00"W
Project: Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 272, 275, 296, and 297; and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and specifically described as follows:

A 74.9 megawatt (gross) electric, (1-hour average), cogeneration facility (biomass--bagasse and wood waste material as the primary fuel, No. 2 fuel oil as a supplementary fuel, and low sulfur coal as an alternate fuel) located at Okeelanta Corporation's sugar mill that is 6 miles south of South Bay, off U.S. Highway 27, Palm Beach County, Florida. The cogeneration facility contains three Zurn spreader-stoker or equivalent steam boilers with a design heat input for each boiler of 715 MMBtu/hr on biomass and 490 MMBtu/hr on fossil fuels. Each boiler will produce approximately 455,400 lbs/hr of steam at 1,500 psig and 975°F. Particulate matter, nitrogen oxides, and mercury emissions from each boiler will be controlled by Research-Cottrell (or equivalent) electrostatic precipitator, Thermal $DeNO_x$ (or equivalent) selective non-catalytic reduction system, and an activated carbon injection system (or equivalent), respectively. Auxiliary equipment includes feed and ash handling systems, steam turbines and condensers, electric generators, cooling towers, and stacks that are 8.0 ft. in diameter and a minimum 199 ft. high.

The UTM coordinates of this facility are Zone 17, 524.9 km E and 2940.1 km N.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below:</u>

1. Application received September 30, 1992.
2. DER letter dated November 3, 1992.
3. KBN letter dated December 4, 1992.
4. Carlton letter dated December 23, 1992.
5. KBN letter dated February 17, 1993.
6. KBN letter dated May 25, 1993.
7. KBN letter dated July 2, 1993.
8. KBN letter dated August 11, 1993.

PERMITTEE:
Okeelanta Power Limited
Partnership

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996

GENERAL CONDITIONS:

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

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

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

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

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

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

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a

GENERAL CONDITIONS:

reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

a. a description of and cause of non-compliance; and

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

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

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

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

PERMITTEE:
Okeelanta Power Limited
Partnership

Permit Number: AC50-219413
PSD-FL-196
Expiration Date: July 1, 1996

GENERAL CONDITIONS:

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration (PSD)
(x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

GENERAL CONDITIONS:

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

SPECIFIC CONDITIONS:

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application. The facility shall be designed, constructed, and operated so that its gross generating capacity shall not exceed 74.9 megawatt (MW), 1-hour average, except during scheduled emission compliance and equipment performance tests. Equipment performance testing in excess of 74.9 shall be limited to a total of 24 hours (cumulative) during the 180-day calendar period after initial firing of each boiler.

The permittee shall provide detailed engineering plans, 30 days after they become available, demonstrating that the steam electric generating system will not produce more than 74.9 MW at design maximum steam conditions. Such demonstration may include plans for installation of a steam pressure relief valve. If the steam electric generating system is designed with a pressure relief valve, such valve shall be installed and maintained as a requirement of this permit.

2. Boilers No. 1, 2 and 3 shall be of the spreader stoker type with a maximum heat input of 715 MMBtu/hr with biomass fuel and 490 MMBtu/hr with fossil fuels.

3. Each boiler shall have an individual stack, and each stack must have a minimum height of 199 feet. The stack sampling facilities for each stack must comply with F.A.C. Rule 17-297.345.

4. Each boiler shall be equipped with instruments to measure the fuel feed rate, steam production, steam pressure, and steam temperature.

5. Each boiler shall be equipped with a:

- -Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
- -Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NO_x; and
- -Carbon injection system (or equivalent) for mercury emissions control.

PERMITTEE:
Okeelanta Power Limited
Partnership

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SPECIFIC CONDITIONS:

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_x), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO).

The monitoring devices shall meet the applicable requirements of Section 17-297.500, F.A.C., and 40 CFR 60.47a. The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the stack or in the stack.

An oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/fuel ratio parameters at an optimum. Operating procedures shall be established based on the initial emission compliance tests required by Specific Condition No. 21 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. An operating plan shall be submitted to the Department within 90 days of completion of such tests.

7. For the electrostatic precipitator, the selective non-catalytic reduction process (SNCR), and the activated carbon injection mercury control system (equivalent controls allowed):

a. The permittee shall submit to the Department copies of technical data pertaining to the selected PM, NO_x, and mercury emission controls within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rates and major design parameters.

8. For the fly ash handling and mercury control system reactant storage systems:

a. The particulate matter filter control system for the storage silos shall be designed to achieve a 0.01 gr/acf outlet dust loading. The permittee must submit to the Department copies of technical data pertaining to the selected particulate emissions control for the mercury control system reactant storage silos within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency, emission rates, and major design parameters.

b. The fly ash handling system (including transfer points and storage bin) shall be enclosed. The ash shall be wetted in the ash conditioner to minimize fugitive dust prior to it being discharged into the disposal bin.

SPECIFIC CONDITIONS:

9. Prior to operation of the source, the permittee shall submit to the Department an operation and maintenance plan that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

10. During land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seeding and mulching of disturbed areas, shall be undertaken and implemented. Any open burning of land clearing debris on this site shall be performed in compliance with Department regulations.

Operational and Emission Restrictions

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application. The facility shall not exceed 74.9 (gross) megawatt generating capacity, 1 hour average, except during emission compliance and equipment performance tests. Equipment performance testing shall be limited to a 180-day calendar period after initial firing of each boiler. The hourly average generation rate shall be recorded in a log and the log retained for at least 2 years. The maximum heat input rate for each steam generator shall not exceed 715 MMBtu/hr when burning 100 percent biomass and 490 MMBtu/hr when burning 100 percent No. 2 fuel oil or low sulfur coal. Maximum heat input to the entire facility (total all three boilers) shall not exceed 11.5×10^{12} Btu per year. Steam production of each boiler shall not exceed an average of 455,418 lbs/hr at 1,500 psig, 975°F.

12. The primary fuel for the facility shall be biomass--bagasse and wood waste material. Authorized wood waste material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter.

The biomass fuel used at the cogeneration facility shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration facility shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter.

The permittee shall perform a daily visual inspection of any wood waste or similar vegetative matter that has been delivered to the facility for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood waste and vegetative matter.

SPECIFIC CONDITIONS:

The permittee shall design and implement a management and testing program for the wood waste and other materials delivered to the facility for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. This program shall be submitted to the Department's Bureau of Air Regulation for review and approval at least 60 days before the commencement of operations of the cogeneration facility. At a minimum, the program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Fuel scheduled for burning shall be inspected daily. Fuel tests shall be conducted weekly for the first year of operations at the facility and monthly thereafter, if the Department determines on the basis of the prior test results that less frequent testing is appropriate. A representative sample of ash for the biomass burned during each month for the first year of operation shall be analyzed for copper, chromium and arsenic by appropriate analytical procedures per 40 CFR 261, Appendix III, described in SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. Wood waste containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned based on an analysis of a composite sample.

13. Any fuel oil burned in the facility shall be "new" No. 2 fuel oil with a maximum sulfur content of 0.05 percent sulfur as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil means an oil which has been refined from crude oil and has not been used in any manner that may contaminate it.

14. Any coal burned in the facility shall be low sulfur coal with a maximum sulfur content of 0.70 percent and a maximum potential emission equivalent to 1.2 lb SO_2/MMBtu.

15. The consumption of No. 2 fuel oil shall be less than 25 percent of the total heat input to each boiler unit in any calendar quarter. Not more than 73,714 tons of coal shall be burned at this facility during any 12-month period. The combined heat input for coal and oil shall be less than 25 percent of the heat input on a calendar quarter basis.

16. The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lbs/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2 emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

SPECIFIC CONDITIONS:

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 4, 5, 6, 10, 11, 12, 14, and 15 (Permit Nos. AO50-169210, 190690, 175414, 190693, 175411, 169215, 189904, and 209094, respectively) may be retained for standby operation. During the period from initial firing to commercial operation, all three cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during this period. If more than 910,836 lb/hr steam is generated in the cogeneration boilers, steam in excess of 910,836 lb/hr must be sent to the Okeelanta sugar mill, and the existing boiler's steam production reduced by an equivalent amount. This period shall not exceed a total duration of 12 months. During this 12-month period, simultaneous operation of the existing boilers and the cogeneration boilers shall not occur on more than a total of 90 calendar days. After the first year of cogeneration facility operation, the existing boilers may be operated only when all three cogeneration boilers are shutdown. During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. These existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. Boiler No. 16 (AC50-191876) may be retained as a standby boiler for the cogeneration facility provided its permit is amended to authorize standby use. Boiler No. 16 may be operated during initial startup, debugging, and testing of the cogeneration facility for a period not to exceed 12 months following initial firing of fuel in the new boilers. After the first year of cogeneration operation, this boiler may be operated only when one or more of the three cogeneration boilers are shutdown. During operation, this boiler must meet all requirements in the current construction or operating permit for the boiler.

19. For the biomass, coal, fly ash, and mercury control system reactant handling facilities:

a. All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimers, for which enclosure is operationally infeasible).

b. Inactive coal storage piles shall be shaped, compacted, and oriented to minimize wind erosion. Sod, wetting agents, synthetic or other appropriate materials shall be used to cover those portions of the inactive coal pile that are prone to wind or water erosion.

PERMITTEE:
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c. Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20 percent opacity.

d. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Particulate matter emissions from each of the three silos shall not exceed a visible emission reading of 5 percent opacity. A visible emission test is to be performed annually on each silo.

20. Visible emissions from any boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	Emission Limit (per boiler)[d]						Total All[e] Three Boilers
	Biomass		No. 2 Oil		Bit. Coal		
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	588.0	---
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	---
Annual average	0.02[a]	---	---	---	1.2[a]	---	1,154.3[f] ÷3 = 384.8
Nitrogen Oxides							
Annual average	0.15[a]	107.3[a]	0.15[a]	73.5[a]	0.17[a]	83.3[a]	862.5 ÷3 = 287.5
Carbon Monoxide							
8-hour average	0.35	250.3	0.2	98.0	0.2	98.0	2,012.5 ÷3 = 670.8
Volatile Organic Compounds	0.06	42.9	0.03	14.7	0.03	14.7	115 = 345.0/3
Lead	2.5×10^{-5}	0.018	8.9×10^{-7}	0.0004	6.4×10^{-5}	0.031	0.17
Mercury	6.3×10^{-6}[b] 0.29×10^{-6}[c]	0.0045[b] 0.00021[c]	2.4×10^{-6}	0.00118	8.4×10^{-6}	0.0041	0.0300 .01

SPECIFIC CONDITIONS:

Beryllium	---	---	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0052
Fluorides	---	---	6.3×10^{-6}	0.003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

[a]Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

[b]Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.

[c]Emission limit for wood waste. Subject to revision after testing pursuant to Specific Conditions Nos. 24 and 25.

[d]The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

[e]Limit heat input from No. 2 fuel to less than 25% of total heat input on a calendar quarter basis, coal to 73,714 tons during any 12-month period, and the combination of oil and coal to less than 25% of the total heat input on a calendar quarter basis.

[f]Compliance based on a 12-month rolling average.

The permittee shall comply with the excess emissions rule contained in F.A.C. Rule 17-210.700. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

Compliance Requirements

21. Stack Testing

   a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 20 (including visible emissions). Tests shall be conducted during normal operations (i.e., within 10 percent of the permitted heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The emission compliance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

   b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as 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), or any other method as approved by the

SPECIFIC CONDITIONS:

Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 3A	Gas analysis when needed for calculation of molecular weight or percent O_2.
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7 or 7E	Nitrogen oxide emissions from stationary sources.
8	Sulfuric acid mist.
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.

SPECIFIC CONDITIONS:

EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

*Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

22. Emission compliance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the emission compliance tests.

23. The permittee shall provide 30 days notice of the equipment performance tests or 15 working days for stack tests in order to afford the Department the opportunity to have an observer present.

24. Stack tests for particulates, NO_X, SO_2, sulfuric acid mist, CO, VOC, lead, mercury, beryllium, fluorides, arsenic, chromium, copper, and visible emissions shall be performed once every six months during the first two years of facility operation in accordance with Specific Conditions Nos. 21, 22, and 23 above. If the test results for the first two years of operation indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the tests will thereafter occur according to the following schedule:

-Annually for particulates, sulfur dioxide,* sulfuric acid mist,* NO_X, CO, VOC, mercury, arsenic, chromium, copper and visible emissions.
-Once every five years (at permit renewal time) for SO_2, sulfuric acid mist, lead, beryllium, and fluorides.

*Test required only during years coal is burned in the boilers.

25. After conducting the initial stack tests required under Specific Condition No. 24 above, a fuel management plan shall be submitted to the Department and Palm Beach County within 90 days specifying the fuel types and fuel quantities to be burned in the facility in order to not exceed the facility annual mercury, lead, beryllium, and flucrides emission limits specified in Condition 20

SPECIFIC CONDITIONS:

above. The plan shall include mercury emission factors based on stack testing, and may include revised mercury emission factors and baseline emission estimates for the existing Okeelanta facility.

Reporting Requirements

26. Stack monitoring, fuel usage, and fuel analysis data shall be reported to the Department's South and Southeast District Offices and to the Palm Beach County Health Unit on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Sections 60.7 and 60.49a, and in accordance with Section 17-297.500, F.A.C.

27. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

28. An application for an operation permit must be submitted to the South District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 27 day
of September, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Department of Environmental
Protection

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Project No.	0990332-013-AC
Draft Permit No.	PSD-FL-196L
Facility ID No.	0990332
SIC No.	4911

PROJECT DESCRIPTION

Okeelanta Power L.P. requested the addition of natural gas as a supplemental fuel for the biomass boilers at the Okeelanta Cogeneration Plant located near the city of South Bay in western Palm Beach County. As discussed in the Technical Evaluation, the biomass boilers were determined to be "electric utility steam generating units". As such, the applicant projected that future representative actual annual emissions will not trigger any PSD significant emissions rates as a result of this project. Therefore, the project is not subject to PSD at this time. However, the applicant is required to submit reports for five representative years of normal operations after completion of construction to ensure that the actual annual emissions do not exceed the PSD significant emissions rates as a result of this project. If the actual emissions do exceed the PSD significant emissions rates, the project is subject to PSD at that time and BACT must be determined for each significant pollutant. A rigorous analysis of the applicable rules is detailed in a similar determination for the Pinellas County Resource Recovery Facility's Capital Replacement Project (Project No. 1030117-003-AC, Permit Nos. PSD-FL-011B & PSD-FL-098B).

The addition of natural gas is not expected to result in increased hourly emissions, however the project is a physical change affecting emissions and requires an air construction permit. Applicable requirements of NSPS Subpart Da were included because natural gas becomes a new regulated fuel under this subpart. Because no increases in hourly or annual emissions are expected, no additional air quality analysis was required. See the Technical Evaluation and Preliminary Determination for a detailed review of this project.

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

Jeffery F. Koerner

12-1-00
(Date)

Jeffery F. Koerner, P.E.
Registration Number: 49441

DARM/BAR - New Source Review Section
Florida Department of Environmental Protection

Memorandum

Florida Department of Environmental Protection

TO:	~~Clair Fancy, Chief – Bureau of Air Regulation~~ *AAL for CHF*
THROUGH	Al Linero, Administrator - New Source Review Section *AAL 12/4*
FROM:	Jeff Koerner, Project Engineer - New Source Review Section *JK*
DATE:	December 4, 2000
PROJECT:	Okeelanta Power Limited Partnership Cogeneration Plant – Addition of Natural Gas Project No. 0990332-013-AC Draft Permit No. PSD-FL-196L

Attached is the public notice package to add natural gas as a supplemental fuel to the biomass boilers at the Okeelanta Cogeneration Plant located near the city of South Bay in western Palm Beach County. As discussed in the attached Technical Evaluation, the biomass boilers have been determined to be "electric utility steam generating units". As such, the applicant has projected that future representative actual annual emissions will not trigger any PSD significant emissions rates as a result of this project. Therefore, the project is not subject to PSD at this time. However, the applicant is required to submit reports for five representative years of normal operations after completion of construction to ensure that the actual annual emissions do not exceed the PSD significant emissions rates as a result of this project. If the actual emissions do exceed the PSD significant emissions rates, the project is subject to PSD at that time and BACT must be determined for each significant pollutant.

The addition of natural gas is not expected to result in increased hourly emissions. However, applicable requirements of NSPS Subpart Da were included because natural gas becomes a new regulated fuel under this subpart. Because no increases in hourly or annual emissions are expected, no additional air quality analysis was required.

Day #74 of the permitting time clock is February 1, 2000. I recommend your approval of the attached Intent to Issue package for this project.

CHF/AAL/jfk
Attachments

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Gus Cepero, Authorized Representative
Okeelanta Power Limited Partnership
P.O. Box 9
South Bay, FL 33493

Project No.	0990332-013-AC
Draft Permit No.	PSD-FL-196L
Facility ID No.	0990332
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Jeffery J. Koerner 12-1-00

Jeffery F. Koerner, P.E.
Registration Number: 49441

(Date)

DARM/BAR - New Source Review Section
Florida Department of Environmental Protection