Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief
Bureau of Air Regulation

THROUGH: Al Linero, Manager
New Source Review Section

FROM: Jeff Koerner, New Source Review Section

DATE: July 25, 2003

SUBJECT: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Increased Heat Input Rates

The applicant requests increases in the hourly and annual heat input rates for the three existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate will not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. The maximum annual heat input will increase from $11.50 \times 10^{+06}$ to $19.97 \times 10^{+06}$ MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The cogeneration boilers have shown increasing reliability and have approached the annual heat input limit. The applicant requests the flexibility to operate the cogeneration units without a synthetic restriction (8760 hours per year). The project is subject to PSD preconstruction review and requires BACT determinations for CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC emissions.

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is August 2, 2003. I recommend your approval of the attached Draft Permit for this project.

Attachments

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

7001 0320 0001 3692 5498

OFFICIAL USE

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

Postmark Here

Sent To
Rodney Williams

Street, Apt. No.; or PO Box No.
PO Box 9

City, State, ZIP+4
South Bay, FL 33493

PS Form 3800, January 2001 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Rodney Williams
Plant Manager
New Hope Power Partnership
P.O. Box 9
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Raphael Ramirez
B. Date of Delivery 8/5/3

C. Signature
X [signature]
☒ Agent
☐ Addressee

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

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

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

2. 7001 0320 0001 3692 5498

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

P.E. CERTIFICATION STATEMENT

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
Okeelanta Cogeneration Plant
Increased Heat Input Rates

PROJECT DESCRIPTION

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate will not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. The maximum annual heat input will increase from $11.50 \times 10^{+06}$ to $19.97 \times 10^{+06}$ MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The cogeneration boilers have shown increasing reliability and have approached the annual heat input limit. The applicant requests the flexibility to operate the cogeneration units without a synthetic restriction (8760 hours per year).

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM_{10}); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO_2); and 555 TPY of volatile organic compounds (VOC). CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC emissions exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants and the Department is required to establish corresponding emissions standards that represent the Best Available Control Technology (BACT). Based on reasonable assurances provided by the applicant and other available information, the emissions standards in the draft permit are based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO_2 and SAM – low sulfur fuels; PM/PM_{10} – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides with prospective removal in the mechanical dust collectors/ESP.

In summary, the BACT determinations for CO, Fl, NOx, SAM, and SO_2 emissions in the current PSD permit were reaffirmed. The BACT determination for VOC was reduced from 0.06 to 0.05 lb/MMBtu based on previous stack test data and to maintain a VOC net increase less than the de minimis compared to the original baseline emissions. The emission standard for particulate matter was reduced from 0.03 to 0.026 lb/MMBtu due to the addition of the mechanical dust collectors and corresponding emissions test data. It also serves as a surrogate standard for lead emissions. The lead emissions standard was removed based on data from 21 stack tests showing very low emission rates and the firing of fuels that contain very low levels of lead. This standard is consistent with the proposed MACT standard for solid fuel-fired industrial boilers.

***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, geological, and meteorological features).*

Jeffery J. Koerner (signature) 7-31-05

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 31, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rodney Williams, Plant Manager
New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Re: Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
New Hope Power Partnership, Okeelanta Cogeneration Plant
Increased Heat Input Rates

Dear Mr. Williams:

One copy of the draft permit authorizing the requested increase in hourly and annual heat input rates for the boilers at the Okeelanta Cogeneration Plant is enclosed. The existing plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. 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, Administrator of the New Source Review Section, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

In the Matter of an
Application for Air Permit by:

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Project No. 0990332-016-AC
Draft Air Permit No. PSD-FL-196(O)
Okeelanta Cogeneration Plant
Increased Heat Input Rates
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. The applicant, New Hope Power Partnership, applied on September 6, 2002 to the Department for a permit authorizing increases in hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The existing plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the 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 modification is required to perform proposed work. The Department intends to issue this air construction permit modification 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 an air construction permit modification. 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) and (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 thirty (30) days from the date of publication of the Public Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, 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, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the Public

Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S. however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

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.

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.

Trina Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Permit package (including the Public Notice, 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 7/31/03 to the persons listed:

Mr. Rodney Williams, Plant Manager*
Mr. James Meriwether, Okeelanta Cogeneration Plant
Mr. David Buff, Golder Associates Inc.
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, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson (Clerk) July 31, 2003 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PERMIT
MODIFICATION OF PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)

New Hope Power Partnership – Okeelanta Cogeneration Plant

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to the applicant, New Hope Power Partnership. The applicant operates an existing cogeneration plant that is located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Okeelanta Cogeneration Plant's authorized representative is Mr. Rodney Williams, Plant Manager, and the mailing address is 8001 U.S. Highway 27 South, South Bay, FL 33493.

The applicant, applied to the Department for a permit to authorize increases in the hourly and annual heat input rates for the existing boilers at the Okeelanta Cogeneration Plant. The maximum hourly heat input rate will increase from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature. The increase in the hourly heat input rate will not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. The cogeneration plant's maximum annual heat input will increase from $11.50 \times 10^{+06}$ to $19.97 \times 10^{+06}$ MMBtu per year, which will relax a permit limit originally taken to avoid new source preconstruction review for several pollutants. The cogeneration boilers have shown increasing reliability and have approached the annual heat input limit. The applicant requests the flexibility to operate the cogeneration units without synthetic operational restrictions.

The existing cogeneration plant is located in Palm Beach County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to federal and state Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following potential increases in emissions in terms of "tons per year" (TPY): 2160 TPY of carbon monoxide (CO); 5 TPY of fluorides (Fl); 1.4 TPY of lead (Pb); 98 pounds per year of mercury (Hg); 741 TPY of nitrogen oxides (NOx); 181 TPY of particulate matter (PM/PM_{10}); 20 TPY of sulfuric acid mist (SAM); 407 TPY of sulfur dioxide (SO_2); and 555 TPY of volatile organic compounds (VOC). Emissions of CO, Fl, Pb, NOx, PM/PM_{10}, SAM, SO_2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

PSD preconstruction review requires the Department to establish emissions standards that represent the Best Available Control Technology (BACT) for each PSD-significant pollutant. Based on reasonable assurances provided by the applicant and other available information, the Department establishes emissions standards in the draft permit based on the following BACT-level controls: CO and VOC – boiler design and good combustion practices; NOx – selective non-catalytic reduction (SNCR); SO_2 and SAM – low sulfur fuels; PM/PM_{10} – mechanical dust collectors followed by an electrostatic precipitator (ESP); Fl and Pb – authorized fuels containing only trace amounts of fluorides and with and prospective removal in the mechanical dust collectors/ESP.

As part of the PSD required preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. A refined analysis was required to evaluate the 3-hour and 24-hour SO_2 increments in the vicinity of the plant (Class II areas) and in the Everglades National Park (nearest PSD Class I area). The following table shows the maximum predicted for SO_2 impacts and PSD increments consumed by all sources in the area, including the project.

PSD CLASS II INCREMENT ANALYSIS – VICINITY OF THE PLANT					
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m³)**	**Impact Greater than Allowable Increment?**	**Allowable Increment (μg/m³)**	**Percent of Increment**
SO_2	24-hr	62	No	91	68%
	3-hr	218	No	512	43%

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK					
Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater than Allowable Increment?	Allowable Increment ($\mu g/m^3$)	Percent of Increment
SO_2	24-hr	4.0	No	5	80%
	3-hr	12.2	No	25	49%

Based on the analyses, the Department has reasonable assurance that the proposed project will not significantly contribute to or cause a violation of any Class I or Class II PSD increments.

The Department will issue the Final Permit with the proposed 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 thirty (30) days from the date of publication of this Public Notice of Intent to Issue 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, F.S. 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 must be filed within fourteen (14) days of receipt of the notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

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:

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida 32301
Telephone: 850/488-0114

Dept. of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 941/332-6975

Palm Beach County Health Dept.
Environmental Health and Engineering
Air Pollution Control Section
901 Evernia Street
West Palm Beach, Florida 33401
Telephone: 561/355-3136

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 project engineer for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATIONS

PROJECT

Project No. 0990332-016-AC
Draft Permit No. PSD-FL-196(O)

New Hope Power Partnership - Okeelanta Cogeneration Plant
Request to Increase Heat Input Rates of Cogeneration Boilers

ARMS Facility ID Nos. 0990332
Emissions Unit Nos. 001 - 003

COUNTY

Palm Beach County

APPLICANT

New Hope Power Partnership
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative: Mr. Rodney Williams, Plant Manager

PERMITTING AUTHORITY

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

July 24, 2003

{Filename: PSD-FL-196(O) TEPD}

1. APPLICATION INFORMATION

Processing Schedule

01/31/02 Department last modified Permit No. PSD-FL-196.

09/06/02 Department received initial application.

10/04/02 Department requested additional information.

11/21/02 Department mailed reminder of request for additional information.

12/17/02 Department received applicant's request for extension of time to submit additional information.

03/04/03 Department received additional information.

03/26/03 Department requested additional information.

05/21/03 Department received additional information.

Facility Description and Location

New Hope Power Partnership operates the Okeelanta Cogeneration Plant (OkCP) located near Highway 27, approximately 6 miles south of South Bay in Palm Beach County, Florida. The plant consists of three cogeneration boilers fired with biomass and fossil fuels. The plant provides process steam to the adjacent sugar mill and refinery (Okeelanta Corporation) and also produces up to 74.9 MW delivered to the electrical power grid. For the purposes of the Department's Prevention of Significant Deterioration (PSD) preconstruction review program and Title V operating permit program, the cogeneration plant, sugar mill, and refinery are considered to be a single facility. The following table identifies the Standard Industrial Classification (SIC) code for each plant.

Owner/Operator	Plant	Standard Industrial Classification
New Hope Power Partnership	Okeelanta Cogeneration Plant	4911 - Electric Services
Okeelanta Corporation	Sugar Mill	2061 - Cane Sugar, Except Refining
	Sugar Refinery	2062 - Cane Sugar Refining

Regulatory Categories

Title III: Existing facility is a major source of hazardous air pollutants (HAPs).

Title IV: Existing facility is not subject to the federal acid rain provisions.

Title V: Existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: Existing facility is a PSD major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: Existing facility operates units subject to the New Source Performance Standards in 40 CFR 60.

Summary of Existing Cogeneration Boilers

The cogeneration boilers are identified as Boiler A (EU-001), Boiler B (EU-002), and Boiler C (EU-003). Each unit is a spreader-stoker boiler designed to fire a combination of wood and bagasse, which will be referred to as "biomass". Wood chips are delivered by independent suppliers from around the state and consist of clean construction and demolition wood debris, dry wood, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Bagasse is received from the adjacent sugar mill and consists of the fibrous, vegetative residue remaining from sugarcane after the milling process. These solid fuels enter through the fuel chute and are pneumatically spread across the furnace grate. Small particles of biomass fuel burn in suspension above the grate. Larger materials burn in a thin, even bed as they move along the grate. Combustion occurs in three stages within a single chamber: moisture evaporation, distillation and burning of volatile matter, and burning of fixed carbon. Natural gas and distillate oil may be fired for startup or as supplemental fuels. Each existing boiler is equipped with the following air pollution control equipment:

- Nitrogen Oxide Controls: A selective non-catalytic reduction (SNCR) system designed to reduce emissions of nitrogen oxides by about 40% with the injection of urea.

- Particulate Matter Controls: Multi-tube cyclone dust collectors followed by an electrostatic precipitator designed to remove more than 99% of the particulate matter.
- Mercury Controls: A system that injects activated carbon into the exhaust flue gas to adsorb mercury for removal by the particulate matter controls. (Originally included for coal firing operation, which is no longer permitted.)

Each boiler is equipped with continuous monitoring systems to monitor and record emissions of carbon monoxide, nitrogen oxides, sulfur dioxide, and stack plume opacity. The following parameters are also monitored and recorded for each unit: fuel feed rate, steam production, steam pressure, steam temperature, flue gas oxygen content and electrical energy production. Other miscellaneous equipment includes: the biomass fuel feed system; the ash handling and storage system; exhaust fans; ductwork and exhaust stacks; steam turbine-electrical generator sets; steam condensers; cooling towers; distillate oil storage tanks; and a diesel fire pump.

Project Description

Construction of the cogeneration boilers was authorized under the original PSD air permit issued in 1993. Due to a netting analysis that included the shutdown of several sugar mill boilers, the original project was only subject to PSD review for emissions of beryllium, fluorides, sulfuric acid mist, and sulfur dioxide (primarily due to the proposed use of coal as an "emergency backup fuel"). Several modifications have been made to the original PSD permit. The most recent occurred in 2002, which included removing coal as an authorized fuel, revising the averaging period for CO emissions, and revising the SO_2 standards for biomass fuels. This modification resulted in revised BACT determinations for carbon monoxide, fluorides, sulfuric acid mist, and sulfur dioxide. The current PSD permit specifies the maximum heat input rate to each cogeneration boiler as 715 MMBtu per hour. The total heat input to all three boilers combined is limited to $11.5 \times 10^{+06}$ MMBtu per year, which effectively limits the annual capacity to approximately 60%. The cogeneration plant was completed in 1997 and has maintained consistent commercial operation since the 1998/1999 sugarcane crop season.

The applicant proposes the following changes:

- Increase the maximum heat input rate for each boiler from 715 to 760 MMBtu per hour by taking the last feedwater heater on each unit out of service to reduce the feedwater temperature; and
- Remove the restriction on the total annual heat input to all three boilers combined.

The increase in the hourly heat input rate would not result in increased electrical generating capacity and is within the manufacturer's maximum continuous steam rating for these units. Due to increased reliability, the cogeneration plant has been able to approach the maximum annual heat input limit reaching $11.4 \times 10^{+06}$ MMBtu during 2000. The applicant requests the flexibility to operate the cogeneration units without restriction (8760 hours per year). The combined requests would result in a combined annual heat input rate of $19.97 \times 10^{+06}$ MMBtu per year.

2. APPLICABLE REGULATIONS

General State Regulations

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

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms

62-212 Preconstruction Review, PSD Requirements, and BACT Determinations
62-212.300 - General Preconstruction Review Requirements
62-212.400 – Prevention of Significant Deterioration of Air Quality

62-213 Operation Permits for Major Sources of Air Pollution (Title V)

62-296 State Emission Limiting Standards
62-296.405 - New Fossil Fuel Steam Generators with More Than 250 Million Btu Per Hour Heat Input.
62-296.410 - Carbonaceous Fuel Burning Equipment
62-296.500 - Reasonably Available Control Technology Requirements for VOC and NOx
62-296.570 - Reasonably Available Control Technology Requirements for Major VOC and NOx Sources

62-297 Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

General Federal Regulations

This project is also subject to the following applicable federal provisions regarding air quality established in the Code of Federal Regulations (CFR) and adopted by reference in Chapter 62-204, F.A.C.

Title 40, CFR	Description
Part 60	Subpart A - General Provisions for NSPS Sources
	Subpart Da - NSPS for Electric Utility Steam Generating Units, Constructed After September 18, 1978
	Subpart Ea - NSPS for Municipal Waste Combustors, Applicability and Exemption Requirements
	Subpart Kb - NSPS for Distillate Oil Storage Tank, Record Keeping Requirements
	Applicable Appendices

Project PSD Applicability

Operation at the requested maximum heat input rates would result in increased emissions. In the following table, the applicant summarizes the net increase in annual emissions from the proposed project.

Table 2A. Applicant's PSD Applicability Analysis

Pollutant	Past Actual Emissions, TPY	Potential Emissions, TPY	Net Change TPY	PSD SER TPY	PSD/BACT?
CO	1335.40	3495.20	2160	100	Yes
NOx	756.60	1498.00	741	40	Yes
PM	127.96	299.59	181	25	Yes
PM_{10}	108.02	299.59	195	15	Yes
SO_2	191.90	599.18	407	40	Yes
VOC	43.93	599.18	555	40	Yes
Lead	0.098	1.50	1.4	0.6	Yes
Mercury	0.0035	0.054	0.049	0.100	No
Fluorides	2.16	6.99	5	3	Yes
Sulfuric Acid Mist	15.71	35.95	20	7	Yes

a. Past actual emissions of the three boilers are based on the 2-year average emissions for 2000 and 2001.

b. The project would also result in 9.07 TPY of fugitive PM emissions and 3.5 TPY of fugitive PM_{10} emissions.

The cogeneration plant is located in Palm Beach County, an area that is currently in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The facility includes three electric utility steam generating units that belong to one of the 28 major facility categories listed in Table 212.400-1, F.A.C. As such, the threshold for a major PSD facility is 100 tons per year. The cogeneration plant is a major PSD facility because at least one regulated pollutant exceeds 100 tons per year. Therefore, new projects and modifications require a PSD applicability review. Emissions increases exceeding the PSD significant emission rates for the regulated pollutants specified in Table 212.400-2, F.A.C. are subject to PSD review and a determination of the Best Available Control Technology.

Therefore, the project is subject to PSD preconstruction review for emissions of carbon monoxide, fluorides, lead, nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. For each of these pollutants, the applicant must review available control technologies and make a recommendation of the Best Available Control Technology (BACT). Based on information provided by the applicant as well as other available information sources, the Department determines BACT for each PSD-significant pollutant. The applicant is required to provide an Air Quality Analysis demonstrating that the proposed project will not adversely impact PSD Class I and II areas and will not contribute significantly to, or cause a violation of, any state or federal ambient air quality standards. The applicant must evaluate air quality impacts from the project upon soils, vegetation, wildlife, and visibility. Finally, the applicant must provide an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

The determination of the Best Available Control Technology (BACT) must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each PSD-significant pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department must also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated goals regarding pollution prevention.

3.1 BACT Review for Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

Emissions of carbon monoxide and volatile organic compounds are emitted as the result of incomplete combustion of the fuels. The firing of distillate oil and natural gas through burners results in relatively low emissions of these pollutants. These fuels are consistent in nature and offer efficient and controlled combustion. However, the firing of wood and bagasse is much less efficient due to the inherent combustion process on the fuel grate as well as wide variability of fuel characteristics including heating value. In addition, these fuels are high in moisture (~ 50% by weight), which results in lower firing temperatures and less efficient combustion. For most large industrial and utility boilers, CO and VOC emissions are controlled by good combustion practices for the given boiler design. These pollutants will be reviewed together because the methods of control are similar.

Applicant Technology Review and Recommendation

Based on previous determinations, the applicant believes that boiler design and good combustion practices are the only technically feasible and economically viable option for controlling CO and VOC emissions from the biomass-fired cogeneration boilers. (See summary tables at the end of this report for a compilation of recent BACT determinations based primarily of EPA's RACT/BACT/LAER Clearinghouse database.) Therefore, the applicant recommends retaining the current CO and VOC emissions standards as BACT, which are:

CO ≤ 0.50 lb/MMBtu, 30-day rolling CEMS average
≤ 0.35 lb/MMBtu, 12-month rolling CEMS average

VOC ≤ 0.06 lb/MMBtu, 3-run test average

The applicant notes that standards based on good combustion practices are primarily dependent on the original boiler design.

Department's Review and Draft BACT Determination

The following technologies are potentially available for reducing CO and VOC emissions.

- *Thermal Incinerator*: The flue gas temperatures can be raised to complete oxidization of CO and VOC emissions resulting in removal efficiencies of greater than 90%. This would require the combustion of additional auxiliary fuel and associated emissions. In the BACT review for VOC emissions, the applicant estimated that a thermal oxidizer would require an additional 146 million standard cubic feet of natural gas per year. However, such systems are more likely to be considered for gas streams having much lower exhaust flow rates and much higher pollutant concentrations. Based on a review of similar boilers, thermal incineration does not appear to be appropriate for this project.
- *Catalytic Incinerator*: Oxidation of CO emissions can be completed at lower temperatures by employing a catalyst resulting in removal efficiencies of approximately 90%. Such a system must be incorporated at a point that maintains the proper operational temperatures; otherwise cooling or heating of the flue gas may be necessary to achieve the required oxidation and protect the catalyst from damage. Typically, catalytic oxidation for combustion sources has been limited to relatively clean exhaust gas streams such as natural gas-fired boilers or combustion turbines. Catalysts can be blinded and/or fouled due to heavy particulate loading of the flue gas. They can also suffer premature deactivation due to poisoning by various compounds present in the flue gas from firing biomass and distillate oil. Once again, such systems are more likely to be considered for gas streams having much lower exhaust flow rates with much higher pollutant concentrations. Based on a review of similar boilers and concerns regarding catalyst blinding, fouling, and early deactivation, catalytic incineration does not appear to be appropriate for this project.
- *Boiler Design with Good Combustion Practices*: The boiler design generally provides a moderately high temperature with sufficient turbulence and residence time at that temperature to complete combustion of the fuel. Based on a given boiler design, operators use good combustion practices to maintain efficient combustion to minimize products of incomplete combustion.

The following additional control technologies are also identified for primarily reducing VOC emissions:

- *Carbon Adsorbers*: Fixed or fluidized carbon beds can be used to adsorb organic gases onto carbon particles. The adsorption process includes a cycle to regenerate the carbon and either condense the concentrated organic stream for recovery or destroy them. Flue gas temperatures are generally maintained at less than 130° F and humidity to less than 50%. Carbon adsorption is not considered technically feasible for this project due to the large flow rates (>300,000 acfm), high flue gas temperatures, and expected low VOC concentrations.

- *Refrigerated Condensers*: This equipment can be used to cool the gas stream to condense and collect the organic vapors. Such systems are generally installed on processes with high VOC concentrations (> 5000 ppmv) when the specific organic compounds can be recovered and used again. Refrigerated condensation is not considered technically feasible for this project due to the large flow rates (>300,000 acfm), high flue gas temperatures, and expected low VOC concentrations (~ 100 ppmv).

The Department was unable to find any previous BACT determinations that relied on add-on control technologies to remove CO and VOC emissions from biomass-fired boilers. All of the determinations in EPA's RACT/BACT/LAER Clearinghouse listed either "good combustions practices" or "no controls feasible". At this time, the Department agrees that the add-on CO/VOC control technologies are not considered appropriate for the project. The Department makes a preliminary determination to retain the following CO standards as BACT based on good combustion practices.

CO ≤ 0.50 lb/MMBtu, 30-day rolling CEMS average
≤ 0.35 lb/MMBtu, 12-month rolling CEMS average

Compliance will be determined by continuously monitoring CO emissions. The above standards were established in a 2002 PSD permit modification and reflect the actual performance of the boilers as constructed based on actual CEMS data. The standards consider the variability of the fuel heating values and moisture contents of the biomass fuels. As shown in the summary tables at the end of this report, these standards are well within the range of recent BACT determinations for biomass-fired boilers, which were all based upon good combustion practices for the given boiler design. The Department reaffirms these standards as the draft BACT determinations for this project, which will increase the hourly heat input by approximately 6%. In addition, the Department will require that CO emissions be reported in terms of "ppmvd @ 3% oxygen" for each hour of operation and averaged for each 24-hour period (day). These are the same units as the proposed MACT standard for large solid fuel-fired industrial boilers. This will provide preliminary data for informational purposes only with regard to the upcoming MACT, which is based on "good combustion practices".

For VOC emissions, the Department reviewed stack test information for the cogeneration boilers to determine actual VOC emission rates based on the boiler design and good combustion practices. Based on about 30 actual stack tests, there is some variation in the VOC emissions between boilers and fuel combinations. The highest tested emission rates are 0.014 lb/MMBtu for wood firing, 0.020 lb/MMBtu for bagasse firing, and 0.036 lb/MMBtu for a combination of these fuels. Based on good combustion practices for the boiler as constructed and the actual tested emission rates, the Department makes a preliminary BACT determination.

VOC ≤ 0.05 lb/MMBtu, 3-run test average conducted at permitted capacity

Compliance will be demonstrated by annual stack tests for each boiler.

3.2 BACT REVIEW FOR NITROGEN OXIDES (NOX)

Applicant Technology Review and Recommendation

The applicant identified selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) as the top two NOx control technologies for boilers firing biomass. SCR is capable of control efficiencies in the range of 70% - 90% and SNCR is capable of control efficiencies in the range of approximately 35% - 70%. The initial application for this project identified a capital cost for SCR of $4,246,000 per boiler, annual operating costs of $3,810,000 per boiler, and total annualized costs of $4,211,000 per boiler. Based on a 70% reduction and 90% capacity factor, the applicant estimated the cost effectiveness for SCR to be approximately $7800 per ton of NOx removed. Initially, the applicant rejected SCR primarily due to costs, but also noted the following additional reasons:

- There is a lack of actual operating experience because SCR has not yet been applied to a boiler firing biomass in the United States.
- Due to concerns of catalyst poisoning, only one SCR vendor (Hamon Research Cottrell) would provide a quote for the project. The catalyst life was guaranteed for only 10,000 hours of operation.
- Due to blinding and poisoning concerns, the SCR would likely be located after the ESP. A reheat system supplying approximately 100 MMBtu per hour would be required to raise the flue gas temperature to the operational level (~700° F) for SCR.

In response to the Department's request for additional information, the applicant identified other available NOx control alternatives. Of these, the applicant rejected the following options as technically infeasible.

- *SCONOx™*: This technology is a proven, proprietary, and patented catalytic oxidation and absorption technology, which is recognized by the EPA as "demonstrated in practice" for the control of NOx emissions from combined cycle gas turbines. However, there are only two known applications of this technology, which are both for combined cycle gas turbine projects. This technology has never been designed for, or demonstrated on, a biomass-fired boiler.
- *Selective Catalytic Reduction (SCR)*: In the applicant's response for additional information, the applicant indicated Hamon Research Cottrell retracted their initial quote after further discussion and recommended the use of an SNCR system for NOx control. Hamon Research Cottrell believed that catalyst deactivation would occur at an unreasonably high rate due to the presence of potassium, sodium, and phosphorous in the exhaust flue gas. Other vendors (Engelhard Corporation, Babcock & Wilcox, and Wheelabrator A.P.C.) declined to provide an SCR system for a biomass-fired boiler. The applicant also summarized results from Swedish pilot plants that use SCR for wood-fired boilers. Data for the first several years shows that the catalyst deactivates 3-4 times faster than similar coal-fired units. The CHEC Research Center in Denmark reports that "... by co-combustion of coal with biomass or separate biomass combustion, SCR catalysts deactivate at an unacceptable rate." In addition, the Lund Institute of Technology in Sweden states that, "Four larger Swedish plants are using the SCR technique in combination with bio-fuel combustion ... The experiences from the first few years on stream show a relatively fast deactivation ... using 100% wood as fuel." Therefore, the applicant does not believe that SCR is technically feasible for biomass-fired boilers.
- *Low-NOx Burners (Biomass Combustion)*: The boilers have low-NOx burners for natural gas and distillate oil. This technology is not applicable to the spreader stoker boiler design.
- *Non-Thermal Plasma Reactor*: This technique generates electron energies in the gas stream that produce gas-phased radicals, such as hydoxyl and atomic oxygen by the collision of electrons with water and oxygen molecules present in the flue gas. These radicals oxidize NOx in the flue gas to form nitric acid, which can be condensed out with a wet condensing precipitator. This technique has never been demonstrated on large-scale boilers or biomass-fired boilers.
- *Oxidant Injection*: Oxidants such as ozone, ionized oxygen, or hydrogen peroxide can be injected in a gas stream to make NOx soluble in water and then removed with a gas absorber. However, this reduction technique has never been demonstrated on large-scale boilers or biomass-fired boilers.

The following table summarizes the applicant's ranking of the remaining NOx control alternatives.

Table 3.2A. NOx Control Alternatives

Control	Efficiency	Rank	Used by Okeelanta
SNCR	35%-55%	1	Yes
Air staging of combustion	50% - 65%	2	Yes
Fuel staging of combustion	50% - 65%	2	No

Steam injection	50% - 65%	2	No
Flue gas recirculation	15% - 25%	3	No
Reburn w/natural gas	15% - 25%	3	No
Overfire air	15% - 25%	3	Yes
Less excess air	15% - 25%	3	No
Combustion optimization	15% - 25%	3	Yes
Reduce air preheat	15% - 25%	3	No
Low-NOx burners, Oil/gas	15% - 25%	3	Yes
Ultra-low nitrogen fuel	ND	4	Yes

The applicant believes that the next highest ranking NOx control technology is SNCR and notes that the existing Okeelanta cogeneration boilers currently employ SNCR, air staging, overfire air, low-NOx gas/oil burners, combustion optimization, and an ultra-low nitrogen fuels (biomass, natural gas, and distillate oil). The Department assumes that the higher ranking of SNCR is due to the existing combination of controls currently in use with the cogeneration boilers. The applicant believes that the existing SNCR system represents the best available control technology for biomass-fired boilers and recommends retaining the current emissions standard as BACT, which is:

NOx $\leq$ 0.15 lb/MMBtu, 30-day rolling CEMS average

The increased hourly heat input rate will result in increased hourly emissions, which triggers the latest revision to the NSPS Subpart Da NOx standard (§60.44a(d)(2)), which is 0.15 lb/MMBtu of heat input. The proposed BACT standard is as stringent as the applicable NSPS standard.

Department's Review and Draft BACT Determination

The Department does not completely accept the applicant's conclusion that SCR is not technically feasible. However, it is recognized that the known worldwide applications of SCR on boilers firing bagasse and wood is very limited, even more so than applications of SCR for refuse-fired plants, for which only non-U.S. applications currently exist. It is acknowledged that, even if SCR is technically feasible, substantial retrofit costs could be incurred to incorporate such a system into the existing configuration of equipment. The existing SNCR system has been successfully used to continuously comply with the current NOx standard (0.15 lb/MMBtu) since commercial operation began. Considering this current level of NOx control with SNCR, the retrofit of a new SCR system with an 85% reduction and 90% annual capacity factor would potentially result in removing an additional 366 tons of NOx per year. However, based on the estimated annualized cost of $4,211,000, the cost effectiveness for this additional level of control would be more than $10,000 per ton of NOx removed. Operating these units near a 90% annual capacity factor would be very difficult due to the down time needed to perform periodic inspection, maintenance and repair. For example, the cogeneration plant had one of its highest years of operation in 2000, during which the annual capacity factor approached only 57%.

A review of EPA's RACT/BACT/LAER Clearinghouse indicates 22 similar biomass-fired boilers with NOx BACT determinations. See the summary tables at the end of this report. Of these, only seven boilers were required to install add-on controls. In each case, SNCR was the chosen technology. The following three facilities list NOx BACT standards that are less than the proposed standard of 0.15 lb/MMBtu.

- Virginia's Multitrade facility consists of three spreader stoker boilers (374 MMBtu/hour), which are about half the size of the Okeelanta boilers. Each boiler fires 100% wood with a NOx limit of 0.10 lb/MMBtu based on a 30-day rolling average. Although permitted for full operation, the plant's actual operation appears more typical of a peaking plant.
- Florida's Ridge Generating Station operates a 630 MMBtu/hour steam generating unit that fires wood, tires, and landfill gas. The NOx standard is 90 lb/hour based on a 30-day rolling average, which is equivalent to

approximately 0.143 lb/MMBtu. It is noted that long-term "lb/hour" emission standards can be much easier to achieve than similar lb/MMBtu standards when factoring in low load operation.

- Florida's Osceola Power Cogeneration Plant is a sister facility to the Okeelanta Cogeneration Plant consisting of two similar spreader stoker boilers. Although the NOx BACT limit is 0.14 lb/MMBtu, the plant is not currently in operation and is in the process of being "re-permitted". The new draft BACT determination specifies a NOx standard of 1.6 lb/MW-hr, which is the new NSPS Subpart Da NOx standard and is approximately equivalent to 0.15 lb/MMBtu.

In considering a lower NOx standard for the cogeneration units, it is important to keep in mind that the existing SNCR system was originally designed to continuously meet a standard of 0.15 lb/MMBtu. Simply requiring a lower limit for the existing control system would likely result in increased urea usage and higher ammonia slip that could potentially cause corrosion problems. The sister facility, the Osceola Cogeneration Plant, initially requested a NOx standard of 0.12 lb/MMBtu to avoid PSD preconstruction review as part of a netting analysis. It did not appear that the SNCR design was any different than that of the Okeelanta Cogeneration Plant. However, about 40% more urea was injected to meet a standard that was only 20% lower. Combined with the high moisture conditions and extended periods of shutdown, the additional ammonia is believed to have caused premature failure of the superheater tubes.

The Department rejects SCR for the existing biomass-fired boilers due to technical concerns regarding catalyst poisoning and the corresponding high costs for retrofitting an SCR system. The Department believes that SNCR represents the appropriate control technology and makes a preliminary determination to retain the current emission standard as the draft BACT standard for NOx emissions as follows.

NOx $\leq$ 0.15 lb/MMBtu, 30-day rolling CEMS average

Compliance will be determined by continuously monitoring NOx emissions.

3.3 BACT Review for Particulate Matter (PM) and Lead (Pb)

Applicant Technology Review and Recommendation

The applicant identified cyclones, wet scrubbers, baghouses, and electrostatic precipitators (ESP) as technically feasible add-on control technologies for removing particulate matter from the flue gas exhaust. Control efficiencies of baghouses and ESPs can be more than 99%. The cogeneration boilers were originally designed with ESPs. In 2000, mechanical dust collectors were installed as pre-controls to prevent overloading the ESP. Actual tests with the mechanical dust collectors and ESP in place indicate particulate matter emission rates in the range of 0.01 to 0.02 lb/MMBtu.

A review of the EPA RACT/BACT/LAER Clearinghouse shows recent BACT determinations ranging from about 0.02 to 0.24 lb/MMBtu. The applicant believes that the combination of mechanical dust collectors / ESP reflects the top level of control, which is comparable to a baghouse. The applicant recommends retaining the current emissions standards as BACT, which are:

PM $\leq$ 0.03 lb/MMBtu, average of 3 test runs

Pb $\leq$ 1.5×10^{-04} lb/MMBtu, average of 3 test runs (if a standard is necessary)

The applicant notes that the standard for lead is proposed at the maximum expected rate due to the variability of lead in the biomass fuels and the inherently low levels of emissions. Based on test data, actual lead emissions are expected to average about 2.6×10^{-05} lb/MMBtu. At this rate, total lead emissions from the cogeneration boilers would be less than 600 pounds per year, which is less than the PSD significant emission rate for lead of 1200 pounds per year.

Department's Review and Draft BACT Determination

The Department also recognizes the combination of the mechanical dust collectors/ESP as capable of the top level of control for reducing particulate matter emissions from biomass-fired boilers. This is consistent with previous BACT determinations listed in EPA's RACT/BACT/LAER Clearinghouse. The Department notes that EPA recently performed an extensive review of existing particulate matter control technologies in support of the recently proposed Maximum Achievable Control Technology (MACT) standards for large industrial boilers. The proposed rule specifies a particulate matter standard of 0.026 lb/MMBtu as a surrogate for showing good control of particulate metal emissions (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium). Based on the available information, the Department proposes the following as the new draft BACT standard for lead and PM emissions.

PM $\leq$ 0.026 lb/MMBtu, average of 3 test runs

A permitting note will be added to reflect that the average emission rate for lead is 2.6 x 10^{-05} lb/MMBtu. The Department notes that three tests conducted on the existing mechanical dust collectors/ESP combination show actual particulate matter emissions of less than half the proposed new standard. Also, the Department will retain the current opacity standard, which is no more than 20% opacity, except for one 6-minute block per hour that shall not be greater than 27% opacity. Compliance with the PM standard will be demonstrated by annual stack tests for each boiler. Compliance with the opacity standard will be demonstrated by a continuous opacity monitor.

3.4 BACT Review for Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)

Bagasse, wood, distillate oil, and even natural gas contain sulfur. During combustion, fuel sulfur is oxidized to sulfur dioxide, which can also lead to emissions of sulfuric acid mist. Generally, wood and bagasse contain low levels of sulfur compared to most fossil fuels. The distillate oil allowed by the current permit is restricted to no more than 0.05% sulfur by weight, which is equivalent to about 0.05 lb/MMBtu of heat input. Natural gas contains almost negligible amounts of sulfur and is typically added as an odorant to aid in leak detection.

Applicant Technology Review and Recommendation

The applicant identified wet, dry, and regenerable flue gas desulfurization (FGD) systems as technically feasible control alternatives. These technologies typically mix wet or dry lime with the flue gas to chemically react with the sulfur dioxide. The sulfur compounds are ultimately removed in the solid and/or liquid waste streams. In regenerable systems, the goal is to produce a concentrated stream of sulfur dioxide or sulfuric acid, which can then be sold. These systems generally achieve control efficiencies greater than 90% depending on the inlet concentration.

The least expensive flue gas desulfurization technique is a lime spray dryer absorber. The applicant submitted a cost analysis based on two bids for a project with similar boilers (Palm Beach Power's Osceola Cogeneration Plant). Capital costs ranged from $4.4 to $6 million and annual operating costs ranged from $700,000 to $800,000 per year. The total annualized costs ranged from $1.6 to $2.0 million per year. Based on a 90% annual capacity factor and 90% control efficiency, the applicant estimated 182 tons per year of SO_2 and fluoride emissions reductions. The cost effectiveness ranged from $10,000 to $12,000 per ton of pollutants removed. Based on this analysis, the applicant rejected the lime spray dryer absorber as not cost effective. The applicant also rejected other flue gas desulfurization techniques as not cost effective because they were expected to be even more costly than the lime spray dryer absorber.

The applicant notes that all of the fuels contain low levels of sulfur. Test data indicates that SO_2 emissions during biomass combustion are much lower than determined stoichiometrically by actual fuel sulfur. It is believed that much of the SO_2 generated during biomass combustion is adsorbed onto alkaline fly ash particles, which are removed by the combination of mechanical dust collectors/ESP. Therefore, the applicant recommends retaining the following standards as BACT based on the known low fuel sulfur fuels.

SO_2 $\leq$ 0.20 lb/MMBtu, 24-hour CEMS average
$\leq$ 0.10 lb/MMBtu, 30-day CEMS average
$\leq$ 0.06 lb/MMBtu, annual CEMS average

Fuel Specification: Distillate oil shall not contain more than 0.05% sulfur by weight.

Compliance will be determined by continuously monitoring SO_2 emissions.

Department's Review and Draft BACT Determination

The Department believes that the applicant's estimated cost effectiveness may be at the high end. However, based on CEMS data collected in 2000 for the New Hope Power cogeneration boilers firing a combination of wood and bagasse, the annual SO_2 emission rate is approximately 0.03 lb/MMBtu. Basing the annual emission reductions from a lime spray dryer absorber on this factor would increase the actual cost effectiveness well above $10,000 per ton. At this level, flue gas desulfurization is clearly not cost effective for the proposed project. Therefore, the Department also rejects add on flue gas desulfurization as not cost effective for this project.

As shown in the summary tables at the end of this report, the EPA RACT/BACT/LAER Clearinghouse lists 26 SO_2 BACT standards for similar biomass-fired boilers ranging from 0.002 to 0.46 lb/MMBtu. All but three of these projects identify the use of "low sulfur fuels" or "no controls feasible". It is important to realize that the actual fuel source is critical when establishing a permit standard based solely on "low sulfur fuels". Two facilities in Maine did require sodium carbonate scrubbers, but the corresponding BACT standard is much higher (0.27 lb/MMBtu) than that proposed by the applicant. The Department notes that these units are probably burning process sludge with a high sulfur content. The third facility, Florida's Ridge Generating Station, operates a lime spray dryer absorber to meet the BACT standard of 0.10 lb/MMBtu; however, this unit also burns tires and landfill gas, which contain much higher concentrations of sulfur. Higher uncontrolled SO_2 emissions from these sources made flue gas desulfurization cost effective. Even so, the proposed SO_2 standard for the cogeneration boilers that is based on a 30-day rolling average and "low sulfur fuels" is equivalent to the "controlled" emission standard for the Ridge Generating Station. Similarly, the proposed annual SO_2 standard for the cogeneration boilers is 40% lower than for the Ridge Generating Station.

Based on a review of the available information for the cogeneration boilers, the Department makes a preliminary determination to retain the existing SO_2 standards as BACT for this project based on low sulfur fuels.

SO_2 0.20 lb/MMBtu, 24-hour CEMS average

0.10 lb/MMBtu, 30-day CEMS average

0.06 lb/MMBtu, annual CEMS average

Fuel Specification: Distillate oil shall not contain more than 0.05% sulfur by weight.

The draft permit will also include requirements to periodically sample and analyze the bagasse and wood for the fuel sulfur content to monitor for significant changes in fuel characteristics. Due to the predicted low levels of sulfuric acid mist emissions, the SO_2 standard and distillate oil sulfur specification will serve as surrogate standards that effectively limit potential emissions of this pollutant.

3.5 BACT FOR FLUORIDES (FL)

Bagasse, wood, and distillate oil can contain trace amounts of fluorides, which convert primarily to hydrogen fluoride gas when combusted in a boiler. Similar to sulfur dioxide, some of the hydrogen fluoride will adsorb onto alkaline fly ash particles and be removed in the downstream mechanical dust collectors and electrostatic precipitators. Full operation of the cogeneration boilers as requested will result potential annual fluoride emissions of approximately 7 tons per year and a PSD significant net emissions increase. It is noted that the applicant's estimate of potential fluoride emissions is based on the highest tested emission rate for 18 individual stack tests (7.0×10^{-04} lb/MMBtu). Based on the average fluoride emission rate (3.0×10^{-04} lb/MMBtu), the maximum annual emissions would be about 3 tons per year, which is the PSD significant emission rate for fluorides.

Applicant Technology Review and Recommendation

Hydrogen fluoride is an acid gas and could be removed using the technologies discussed for controlling emissions of sulfur dioxide. However, the previous analysis for sulfur dioxide emissions (which included removal of hydrogen fluoride) showed that such equipment was not cost effective for this project. Other than Florida's Okeelanta and Osceola Cogeneration Plants, EPA's RACT/BACT/LAER Clearinghouse shows only one other BACT determination for fluoride emissions from a biomass-fired boiler, Virginia's Multitrade Limited Partnership. The BACT standard for the Multitrade boiler is 0.0017 lb/MMBtu, which is more than twice the highest tested emission rate for the cogeneration boilers. The applicant requests that the current fluoride BACT be retained, which is the use of low fluoride fuels and the existing mechanical dust collectors and electrostatic precipitator.

Department's Review and Draft BACT Determination

Based on existing test data for Okeelanta's cogeneration boilers, actual fluoride emissions are very low. As discussed for sulfur dioxide emissions, the cost to install add-on control equipment to further reduce fluoride emissions would be prohibitive. The Department intends to retain the existing fluoride BACT as follows.

Fluorides *BACT is the use of low-fluoride fuels and prospective removal with the fly ash in the mechanical dust collectors and electrostatic precipitator.*

The Department believes that sufficient data exists to show that fluoride emissions from the cogeneration boilers are relatively low. No further testing will be required.

4. AIR QUALITY MODELING

Introduction

The applicant predicts the proposed project will increase PM_{10}, SO_2, NOx, CO, sulfuric acid mist (SAM), fluorides, Pb and VOC emissions at levels in excess of PSD significant amounts. PM_{10}, SO_2 and NOx are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels, and significant monitoring concentrations (de minimis concentrations) defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and a de minimis concentration defined for it. Pb is a criteria pollutant and has only AAQS and a de minimis concentration defined for it. Fluorides are a non-criteria pollutant and have no AAQS or PSD increments defined for them; however fluorides do have a de minimis concentration. SAM is a non-criteria pollutant and has no applicable AAQS, PSD increments or PSD significance levels defined for it; therefore, no air quality impact analysis was required for SAM. VOC is a precursor for ozone, which is a criteria pollutant. There are no applicable AAQS, PSD increments, PSD significance levels for VOC. However, projects with net increases of more than 100 tons per year of VOC require an ambient impact analysis.

The air quality impact analyses required by the PSD regulations for this project include:

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

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact, PSD increment, and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA and Department guidelines. Good Engineering Practice (GEP) stack height means the greater of: (1) 65 m (213 ft) or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The existing boiler stacks are approximately 200 feet tall and do not exceed the GEP stack height regulations. Therefore, the potential for building downwash to occur was considered in the modeling analysis for these stacks.

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

Analysis of Existing Air Quality

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

The table below shows maximum project air quality impacts for comparison to these de minimis levels.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than De Minimis?**	**De Minimis Level ($\mu g/m^3$)**
PM_{10}	24-hr	1	NO	10
CO	8-hr	5	NO	575
NO_2	Annual	0.6	NO	14
VOC	Annual Emission Rate	555 TPY*	YES	100 TPY
SO_2	24-hr	9	NO	13
Lead	3-mo	0.0044	NO	0.1
Fluorides	24-hr	0.017	NO	0.25

* The original project included the permanent shutdown of several existing boilers with baseline VOC emissions of 402 tons per year. Revised potential VOC emissions for the boilers are 499, which would be a net increase of only 97 tons per year over the original 1991/1992 baseline years.

As shown in the table all pollutant emissions, with the exception of VOC are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. However, since VOC impacts from the project are predicted to be greater than the de minimis level; the applicant is not exempt from preconstruction monitoring for this pollutant. The applicant may instead satisfy the preconstruction monitoring requirement using previously existing representative data. These data do exist from ozone monitors located in the urbanized West Palm Beach area to the east of the project, and show no violation of any ozone standard. In addition SO_2 data has been collected in the Belle Glade area. These data are appropriate to establish background concentrations for use in the SO_2 AAQS analysis. The background concentrations for SO_2 are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	**Averaging Time**	**Background Concentration ($\mu g/m^3$)**
SO_2	Annual	5
	24-hour	13
	3-hour	47

Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

PSD Class II Area Model

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

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

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

PSD Class I Area Model

Since the PSD Class I Everglades National Park (ENP) is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. For this project, the CALMET model produced a modeling domain extending 470 km in the north-south direction by 450 km in the east-west direction. The modeling domain was produced by using 1990 meteorological data from 3 upper air, 8 surface, and 23 precipitation stations located throughout the state of Florida.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 1000 receptors were placed along the facility's restricted property line and out to 35 km from the facility, which is located in a PSD Class II area. Modeling refinements were done, as needed, by using a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of one or two degrees. 126 receptors were placed in the Everglades National Park (ENP) PSD Class I area, which is located 92 km to the south at its closest boundary. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in a PSD Class II area in the vicinity of the facility or in any PSD Class I area. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

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

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?	Radius of Significant Impact (km)
PM_{10}	Annual	0.2	1	NO	----
	24-hr	1.2	5	NO	----
CO	8-hr	5	500	NO	----
	1-hr	22	2,000	NO	----
NO_2	Annual	0.5	1	NO	----
SO_2	Annual	0.3	1	NO	----
	24-hr	9	5	YES	11
	3-hr	32	25	YES	11
VOC	AER	555 TPY	100 TPY	YES	----

MAXIMUM PROJECT IMPACTS IN THE ENP FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.002	0.2	NO
	24-hr	0.06	0.3	NO
NO_2	Annual	0.005	0.1	NO
SO_2	Annual	0.004	0.1	NO
	24-hr	0.45	0.2	YES
	3-hr	1.1	1.0	YES

As shown in the tables, the maximum predicted 24-hr and 3-hr air quality impacts due to SO_2 emissions from the proposed project are greater than the PSD Class II significant impact levels in the vicinity of the facility and the PSD Class I significant impact levels in the Everglades National Park (ENP). Therefore, the applicant was required to do full impact SO_2 modeling in the vicinity of the facility, within the applicable significant impact area, to determine the impacts of the project along with all other sources in the vicinity of the facility. The significant impact area in the vicinity of the facility is based upon the predicted radius of significant impact. The applicant was required to do full impact SO_2 PSD increment modeling in the ENP.

As previously shown, potential VOC emissions increases are above the de minimis level of 100 tons per year, which requires an analysis of the impacts from the project on ambient ozone concentrations. Ozone is not directly emitted from stationary sources. Impacts of VOC emissions on ozone are usually not seen locally, but contribute to the regional formation of ozone. The regional ozone monitors in the county suffice for any background ozone pre-construction monitoring requirements. The main impact on ozone from stationary sources in the area is due to nitrogen oxides emissions (NOx) rather than VOC emissions. Furthermore, ozone formation occurs on a regional basis and includes the contributions of emissions from traffic, power plants throughout the region, miscellaneous VOC sources throughout the region, etc. The Palm Beach County Health Department is the approved local air pollution control program in the county. Each year, the Health Department compiles an annual air emissions inventory. Based on the March 2003 report presented to the county commissioners, almost half of the VOC emissions in the county originate from mobile sources of air pollution, such as automobiles and construction vehicles. The maximum potential VOC emissions from the cogeneration boilers operating 24 hours per day at full capacity would represent less than 1% of the total actual annual VOC emissions in the county.

It is further noted that actual VOC emissions from the cogeneration boilers have been very low (< 50 tons per year). Based on the preliminary BACT determination, the maximum potential VOC emissions are 499 tons per year compared to the original 1991/1992 actual baseline VOC emissions of 402 tons per year from the previous boilers, which were shut down as a result of the cogeneration project. Therefore, the revised BACT standard maintains net VOC emissions increases from the original project below the 100 ton per year de minimis level. In addition, the increases in the short term and long term maximum heat input rates are not likely to result in any meaningful changes in VOC emissions.

The applicant presented the potential VOC emissions increases to the Department and discussed available options to predict potential impacts associated with the emissions and formation of ozone. However, there are no approved stationary point source models available for use in predicting ozone impacts. Actual annual VOC emissions from the cogeneration boilers are expected to be less than 100 tons per year based on past performance test data and predicted operational levels. Ambient ozone monitoring data collected in Palm Beach County over the last several years show attainment with the current ozone standards and predict attainment with the proposed new ozone standards. Based on the available information, the Department determines that the use of a regional model incorporating the complex chemical mechanisms for predicting ozone formation is not suitable for this project, nor would it be sensitive enough to evaluate impacts associated with the changes from this project.

Receptor Grids for Performing PSD Increments and AAQS Analyses

For the PSD Class II increment and AAQS analyses, receptor grids normally are based on the size of the significant impact area for each pollutant. As shown in the previous section, the sizes of the significant impact areas for the required SO_2, analyses were 11 km.

PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 for PM_{10} and SO_2 (the baseline year was 1975 for existing major sources of PM_{10} and SO_2), and 1988 for NO_2 (the baseline year was 1988 for existing major sources of NO_2). The emission values that are input into the model for predicting increment consumption are based on maximum potential emissions from increment-consuming project sources and all other increment-consuming sources in the vicinity of the facility. The maximum predicted PSD Class I and II area SO_2 increments consumed by this project and all other increment-consuming sources in the vicinity of the facility and in the ENP are shown below. The results show that all of the maximum predicted impacts are less than the allowable increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Impact Greater than Allowable Increment?**	**Allowable Increment (μg/m^3)**
SO_2	24-hr	62	NO	91
	3-hr	218	NO	512

PSD CLASS I INCREMENT ANALYSIS – EVERGLADES NATIONAL PARK				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Impact Greater than Allowable Increment?**	**Allowable Increment (μg/m^3)**
SO_2	24-hr	4.0	NO	5
	3-hr	12.2	NO	25

AAQS Analysis

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

AMBIENT AIR QUALITY IMPACTS						
Pollutant	**Averaging Time**	**Major Sources Impact (μg/m^3)**	**Background Concentration (μg/m^3)**	**Total Impact (μg/m^3)**	**Total Impact Greater than AAQS?**	**Florida AAQS (μg/m^3)**
SO_2	Annual	20	5	25	NO	60
	24-hr	132	13	145	NO	260
	3-hr	470	47	517	NO	1300
Pb	Quarterly	0.001	0	0.001	NO	1.5

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM_{10}, NOx CO, Pb and SO_2 emissions as a result of the proposed project, including all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected. A regional haze analysis using the long-range transport model CALPUFF was done for the Everglades National Park Class I area. This analysis showed no significant impact on visibility in this area. Total nitrogen and sulfur deposition rates on the ENP Class I were also predicted using CALPUFF. The maximum predicted deposition rates are below the National Park Service recommended deposition threshold levels for nitrogen and sulfur.

Growth-Related Air Quality Impacts

The proposed modification will not significantly change employment, population, housing or commercial or industrial development in the area to the extent that a significant air quality impact will result.

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the revised specific conditions of the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for the project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Table 1. Recent CO BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Initial Permit Date	Facility Name	Capacity MMBtu/hr	CO Limit lb/MMBtu	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.3	GCPs; wood
AL-0099	1997	Mead Container Board	622	0.4	GCPs; wood
AL-0079	1994	Weyerhaeuser Company	91	1.4	GCPs; wood
AL-0107	1998	Wellborn Cabinet Inc.	30	0.8	GCPs; wood
AL-0112	1997	Champion International	710	0.30	GCPs; wood
AL-0122	1998	Gulf States Paper Corp.	98	0.5	GCPs; wood
CT-0007	>1991	Bio-Gen Tarrington Partnership	208	0.29	GCPs; wood
FL-?	1985	US Sugar Clewiston Boiler 4	633	6.5	GCPs; bagasse
FL-0011	1981	Atlantic Sugar Boiler 5	255	6.5	GCPs; bagasse
FL-0220	1996	Sugar Cane Growers Coop.	504	5.5	GCPs; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	6.5	GCPs; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.35, 12-month	GCPs; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	0.32	GCPs; wood
LA-0074	1991	Willamette Industries, Inc.	940	0.30	GCPs; wood
ME-0013	1991	Beaver-Livermore Falls	533	0.30	GCPs; wood
MI-0139	1989	Hillman Limited Partners	300	0.35	GCPs; wood
MI-0147	1991	Cogeneration Michigan, Inc.	293	0.35	GCPs; wood
MI-0151	1990	Grayling Generating Station	450/523	0.40	GCPs; wood
MI-0180	1992	Cogeneration Michigan, Assoc.	523	0.40	GCPs; wood
MS-0023	1995	Georgia Pacific, Gloster	244	0.69	GCPs, wood
MS-0026	1995	Weyerhaeuser Company	90	0.4	GCPs; wood
MT-0005	1995	Plum Creek, Columbia Falls	292	1.6	GCPs; wood
MT-0007	1997	Plum Creek, Evergreen	225	2.25	GCPs; wood
NH-0003	1990	Pinetree Power, Bethlehem	289	0.50	GCPs; wood
NH-0004	1990	Pinetree Power, Tamworth	404	0.50	GCPs; wood
NY-0055	1994	KES Chateauguay Project	275	0.35	GCPs; wood
SC-0045	1996	Willamette Ind., Marlboro	470	0.3	GCPs; wood
PA-0093	1992	Newman Paper Co.	129	0.3	GCPs; wood
VA-0174	1992	Mulitrade Ltd. Partnership	373	0.35	GCPs; wood
VA-0237	1996	Vaugan Furniture Co.	28	0.85	GCPs; wood
VT-0004	1990	Ryegate Wood Energy Co.	300	0.30	GCPs; wood
WA-0276	1993	Scott Paper Co.	718	0.50	GCPs; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "GCPs" means good combustion practices for a given boiler design.

Table 2. Recent NOx BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Initial Permit Date	Facility Name	Capacity MMBtu/hr	NOx Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.25	GCPs; wood
AL-0099	1997	Mead Container Board	622	0.25	GCPs; wood
AL-0079	1994	Weyerhaeuser Company	91	0.23	GCPs; wood
AL-0107	1998	Wellborn Cabinet Inc.	30	0.46	GCPs; wood
AL-0112	1997	Champion International	710	0.25	GCPs; wood
AL-0116	1997	Gulf States Paper Corp.	775	0.3	GCPs; wood
AL-0122	1998	Gulf States Paper Corp.	98	0.3	GCPs; wood
CT-0147	2001	Killingly Energy	517	0.18	SNCR; wood
FL-?	1985	US Sugar Clewiston Boiler 4	633	0.20	GCPs; bagasse
FL-0011	1981	Atlantic Sugar Boiler 5	255	0.16	GCPs; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.25	GCPs; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.15	SNCR; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	0.14	SNCR; wood
LA-0074	1991	Willamette Industries, Inc.	940	0.30	GCPs; wood
ME-0021	2001	SD Warren Co. - Skowhegan	1300	0.20	SNCR; wood
ME-0022	2001	SD Warren Co. – Somerset	900	0.20	SNCR; wood
ME-0024	1992	Beaver -Ashland Alternative Energy	534	0.15	SNCR; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.25, 30-day	GCPs; wood
MI-0139	1989	Hillman Limited Partners	300	0.15	SNCR; wood
MI-0147	1991	Cogeneration Michigan, Inc.	293	0.21	SNCR; wood
MI-0151	1990	Grayling Generating Station L.P.	450/523	0.15	SNCR; wood
MI-0180	1992	Cogeneration Michigan, Assoc.	523	0.15	SNCR; wood
MN-0033	1998	Potlatch Corporation	140	0.3	GCPs; wood
MS-0023	1995	Georgia Pacific Corp. – Gloster	244	0.3	GCPs, wood
MS-0026	1995	Weyerhaeuser Company	90	0.23	GCPs; wood
MT-0007	1997	Plum Creek Mfg. – Evergreen	225	0.46	GCPs; wood
ND-0018	1998	Archer Daniels Mid. – Northern Sun	200	0.20	GCPs; hulls
NH-0003	1990	Pinetree Power, Inc. - Bethlehem	289	0.30	GCPs; wood
NH-0004	1990	Pinetree Power, Inc. Tamworth	404	0.265	GCPs; wood
NY-0055	1994	KES Chateauguay Project	275	0.23	GCPs; wood
SC-0045	1996	Willamette Industries - Marlboro	470	0.3	GCPs; wood
PA-0093	1992	Newman Paper Company	129	0.3	GCPs; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.1	SNCR; wood
VA-0237	1996	Vaugan Furniture Company	28	0.20	GCPs; wood
VT-0004	1990	Ryegate Wood Energy Co.	300	0.25	GCPs; wood
WA-0276	1993	Scott Paper Company	718	0.25, 30-day	GCPs; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. GCPs means good combustion practices for a given boiler design.

Table 3. Recent PM BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Date	Facility Name	Capacity MMBtu/hr	PM Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.10	ESP; wood
AL-0099	1997	Mead Container Board	622	0.03	ESP; wood
AL-0079	1994	Weyerhaeuser Company	91	0.15	Venturi Scrubber; wood
AL-0112	1997	Champion International	710	0.03	ESP; wood
AL-0122	1998	Gulf States Paper Corp.	98	0.10	ESP; wood
CT-0147	2001	Killingly Energy	517	~0.011	ESP; wood (5.69 lb/hr)
FL-?	1985	US Sugar Clewiston Boiler 4	633	0.03	WIP; bagasse
FL-0011	1981	Atlantic Sugar Boiler	255	0.15	WIP; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.030	ESP; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.03	ESP; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	See comment	Baghouse; wood (0.008 gr/dscf)
ME-0021	2001	SD Warren Co., Skowhegan	1300	0.03	ESP; wood
ME-0022	2001	SD Warren Co., Somerset	900	0.03	ESP; wood
ME-0024	1992	Beaver, Ashland Alt. Energy	534	0.02	ESP; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.036	ESP; wood
MI-0139	1989	Hillman Limited Partners	300	0.03	ESP; wood
MI-0147	1991	Cogeneration Michigan, Inc.	293	0.03	Baghouse; wood
MI-0151	1990	Grayling Generating Station	450/523	0.03	ESP; wood
MI-0180	1992	Cogeneration Michigan, Assoc.	523	0.03	ESP; wood
MS-0023	1995	Georgia Pacific Corp., Gloster	244	0.10	Unknown, wood
MS-0026	1995	Weyerhaeuser Company	90	0.10	Unknown; wood
ND-0018	1998	Archer Daniels Mid., N. Sun	200	0.24	ESP; hulls
NH-0003	1990	Pinetree Power, Bethlehem	289	0.03	ESP; wood
NH-0004	1990	Pinetree Power, Tamworth	404	0.025	ESP; wood
NY-0055	1994	KES Chateauguay Project	275	0.038	ESP; wood
OK-0038	1996	Valliant	900	0.10	Wet Scrubber; wood
SC-0045	1996	Willamette Industries, Marlboro	470	0.05	ESP; wood
PA-0093	1992	Newman Paper Co.	129	0.10	Baghouse; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.02	ESP; wood
VA-0237	1996	Vaugan Furniture Co.	28	See comment	Multiclones; wood; (36.8 TPY)
VT-0004	1990	Decker International	300	See comment	ESP; wood; (0.0007 gr/dscf)
WA-0276	1993	Scott Paper Co.	718	See comment	Baghouse; wood; (0.011 gr/dscf)

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "WIP" means wet impingement scrubber.

Table 4. Recent SO_2 BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Date	Facility Name	Capacity MMBtu/hr	SO_2 Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.30	LSF; wood
AL-0099	1997	Mead Container Board	622	0.02	LSF; wood, sludge
AL-0116	1997	Gulf States Paper Corp.	775	0.46	LSF; wood
CT-0007	>1991	Bio-Gen Tarrington Partnership	209	0.10	LSF; wood
CT-0147	2001	Killingly Energy	517	0.044	LSF; wood
FL-?	1985	US Sugar Clewiston Boiler 4	633	0.06	LSF; bagasse
FL-0011	1981	Atlantic Sugar Boiler 5	255	0.05	LSF; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.17	LSF; bagasse
FL-0069	1993	New Hope Power, 3 Boilers	715	0.06, 12 month	LSF - wood, bagasse
FL-0070	1993	Osceola Power L.P.	760	0.05, 30-day	LSF - wood, bagasse
FL-0198	1992	Ridge Generating Station	630	0.10	LSDA; wood, tires, LF gas
LA-0074	1991	Willamette Industries, Inc.	940	0.008	LSF; wood
ME-0013	1991	Beaver-Livermore Falls	534	0.023	LSF; wood
ME-0021	2001	SD Warren Co. - Skowhegan	1300	0.27	Na SDS; wood
ME-0022	2001	SD Warren Co. - Somerset	900	0.27	Na SDS; wood
ME-0024	1992	Beaver -Ashland Alternative Energy	534	0.014	LSF; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.12	LSF; wood
ME-0139	1989	Hillman Ltd. Partners	300	0.018	LSF; wood
MS-0023	1995	Georgia Pacific Corp. – Glostee	244	0.017	LSF, wood
ND-0018	1998	Archer Daniels Mid. - Northern Sun	200	0.002	LSF; hulls
ND-0018	1998	Archer Daniels Mid. - Northern Sun	280	0.002	LSF; hulls
NY-0055	1994	KES Chateauguay Project	275	0.030	LSF; wood
OK-0038	1996	Valliant	900	0.80	LSF; wood
SC-0045	1996	Willamette Industries - Marlboro	470	0.10	LSF; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.016	LSF; wood
WA-0276	1993	Scott Paper Company	718	0.010	LSF; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "LSF" means low sulfur fuels. "LSDA" means lime spray dryer absorber. "Na SDA" means sodium spray dryer absorber. "LF gas" means landfill gas.

Table 5. Recent VOC BACT Determinations for Similar Biomass-Fired Boilers

RBLC ID	Date	Facility Name	Capacity MMBtu/hr	VOC Limit lb/MMBTU	Controls, Fuels and Comments
AL-0047	1990	Alabama River Pulp, Co.	266	0.03	GCPs; wood
AL-0116	1997	Gulf States Paper Corp.	775	0.03	GCPs; wood
CT-0147	2001	Killingly Energy	517	0.05	GCPs; wood
FL-?	2001	US Sugar Clewiston Boiler 4	633	0.06	GCPs; bagasse
FL-0011	2001	Atlantic Sugar Boiler 5	255	0.25	GCPs; bagasse
FL-0094	1995	US Sugar Clewiston Boiler 7	738	0.212	GCPs; bagasse
FL-0069	2002	New Hope Power, 3 Boilers	715	0.06	GCPs; wood/bagasse
FL-0198	1992	Ridge Generating Station	630	0.035	GCPs; wood
LA-0074	1991	Willamette Industries, Inc.	940	0.10	GCPs; wood
ME-0021	2001	SD Warren Co. – Skowhegan	1300	0.007	GCPs; wood
ME-0022	2001	SD Warren Co. – Somerset	900	0.10	GCPs; wood
ME-0024	1992	Beaver -Ashland Alternative Energy	534	0.016	GCPs; wood
ME-0026	1999	Wheelabrator Sherman Energy	315	0.03	GCPs; wood
MI-0151	1990	Grayling Generating Station	450/523	0.05	GCPs; wood
NH-0003	1990	Pinetree Power, Inc. - Bethlehem	289	0.096	GCPs; wood
NH-0004	1990	Pinetree Power, Inc. Tamworth	404	0.096	GCPs; wood
NY-0055	1994	KES Chateauguay Project	275	0.10	GCPs; wood
OK-0038	1996	Valliant	900	0.047	GCPs; wood
SC-0045	1996	Willamette Industries - Marlboro	470	0.10	GCPs; wood
VA-0174	1992	Mulitrade Limited Partnership	373	0.07	GCPs; wood
VT-0004	1990	Ryegate Wood Energy Co.	300	0.03	GCPs; wood
WA-0276	1993	Scott Paper Company	718	0.50	GCPs; wood

Notes:

a. Recent BACT determinations primarily based on data from EPA's RACT/BACT/LAER Clearinghouse.

b. "GCPs" means good combustion practices for a given boiler design.

DRAFT PERMIT

PERMITTEE

New Hope Power Partnership
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, FL 33493

Authorized Representative:
Mr. Rodney Williams, Plant Manager

Air Permit No. PSD-FL-196(O)
Project No. 0990332-016-AC
Okeelanta Cogeneration Plant
SIC No. 4911
Palm Beach County

PROJECT AND LOCATION

The original PSD permit authorized the construction of a biomass and fossil fuel-fired 74.9 MW cogeneration plant adjacent to Okeelanta Corporation's sugar mill and refinery. The original PSD permit expired on July 1, 1996. The permittee obtained several previous permit modifications that extended some construction-related activities as well as revised specific conditions of the permit. This permit modification authorizes an increase in the hourly heat input rate from 715 to 760 MMBtu per hour per boiler and removes the previous limit on the annual heat input rate ($11.5 \times 10^{+06}$ MMBtu per year) for the three boilers combined. As a result of the changes, BACT determinations were required for emissions of carbon monoxide, fluorides, lead, nitrogen oxides, particulate matter, sulfur dioxide, sulfuric acid mist, and volatile organic compounds. In addition, Condition No. 15 was revised to simply require permanent shutdown of the existing Okeelanta sugar mill boilers, which were part of the netting analysis for the original project.

The cogeneration plant is located off U.S. Highway 27 approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.90 km East, and 2940.10 km North. The map coordinates are latitude 26° 35' 00 " N and longitude 80° 45' 00" W.

STATEMENT OF BASIS

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

CONTENTS

(DRAFT)

Michael G. Cooke, Director
Division of Air Resources Management

Effective Date

FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including packaging and transshipment activities. New Hope Power Partnership operates a 74.9 net MW cogeneration plant that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid (SIC 4911). This permit addresses the cogeneration plant, which consists of the following emissions units.

ID	Emission Unit Description
001	Cogeneration Boiler A (760 MMBtu per hour)
002	Cogeneration Boiler B (760 MMBtu per hour)
003	Cogeneration Boiler C (760 MMBtu per hour)
004	Material handling and storage

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs).

Title IV: The existing facility does not operate any units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD major source of air pollution with respect to Rule 62-212.400, F.A.C.

PPSC: The existing facility is not subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because it produces less than 75 MW of steam-generated electrical power.

NSPS: The existing facility operates units subject to the New Source Performance Standards in 40 CFR 60, including Subparts Da and Db (boilers) and Subpart Kb (fuel storage tanks).

PERMITTING AUTHORITY

All documents related to PSD applications for permits to construct or modify shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate the cogeneration plant shall be submitted to the Air Resource Section of the Department's South District Office at P.O. Box 2549, Fort Myers, Florida 33902-2549. Copies of all such documents shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029. Copies of all such documents shall be submitted to the Air Resources Section at the South District Office of the Florida Department of Environmental Protection (DEP) at 2295 Victoria Avenue, Suite 364 in Fort Myers, Florida 33902-2549.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Format

Appendix B. General Conditions

Appendix C. Standard Requirements

Appendix D. Final BACT Determinations

Appendix E. Continuous Monitor Requirements

RELEVANT DOCUMENTS

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

- Air Permit No. PSD-FL-196 issued September 27, 1993 and all subsequent modifications.
- Permit application received on September 6, 2002 and all related correspondence to make complete.

CITATION FORMAT

Appendix A of this permit describes the format used to cite applicable rules and regulations as well as previous permitting actions.

1. General Conditions: The permittee is subject to, and shall operate under, the attached General Conditions listed in Appendix B of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, and 60 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Permit Expiration: The original expiration date for the construction of this plant was July 1, 1996. Construction of the cogeneration plant is complete and commercial operation has commenced. This revised permit does not authorize any additional construction. <u>The expiration date of this revised permit is September 1, 2004 strictly for the purpose of processing a Title V air permit revision to incorporate these changes. All physical construction is complete. [Rule 62-4.210(2), F.A.C.]</u>

4. Effective Date: The effective date of the modified PSD permit is specified on the placard page (page 1).

5. Relaxations of Restrictions on Pollutant Emitting Capacity: If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7, 1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]

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

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. Title V Permit Revision: Within 90 days of the effective date of this modified PSD permit, the permittee shall submit an application for a revised Title V permit to incorporate the changes. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. As necessary, the application shall include a Compliance Assurance Monitoring Plan. The application shall be submitted to the Department's South District Office with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

This section of the permit addresses the following emissions units.

Emissions Units 001, 002, and 003: Cogeneration Boilers A, B, and C *Description*: Each unit is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately ~~455,400~~ 506,100 pounds per hour of steam at 1500 psig and 975° F. *Fuels and Capacity*: The primary fuel is biomass (~~715~~ 760 MMBtu per hour), which includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. Auxiliary fuels include natural gas (~~400~~ 605 MMBtu per hour) and very low sulfur distillate oil (490 MMBtu per hour). *Controls*: Pollution control equipment includes low-NOx burners for gas firing, a selective non-catalytic reduction system to reduce nitrogen oxides emissions, mechanical dust collectors and an electrostatic precipitator to reduce particulate matter emissions, and an activated carbon injection system to reduce potential mercury emissions. Good operating practices and the efficient combustion of clean, low-sulfur fuels minimizes emissions of carbon monoxide, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. *Stack Parameters*: Exhaust gases exit a 10 feet diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately ~~246,000~~ 319,000 acfm at ~~295~~ 352° F.
Emissions Unit 004: Material handling and storage including unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers, silos, and storage tanks.

CONSTRUCTION DETAILS

1. Generating Capacity: Construction of the proposed cogeneration plant shall reasonably conform to the plans described in the application. The plant shall be designed, constructed, and operated such that the generating capacity does not exceed 74.9 net megawatt (MW) based on a 1-hour average. The owner or operator shall not modify the cogeneration plant in any way that would cause the plant to exceed the limit on maximum net generating capacity. The hourly average net generation rate shall be recorded and retained for at least 5 years.
2. Boiler Design: The cogeneration boilers shall consist of spreader stoker units designed to fire biomass as the primary fuel with pipeline natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain a permit modification before firing any other fuel (including coal) not specifically authorized by this permit.}*
3. Stack: Each boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack must comply with Rule 62-297.345, F.A.C.
4. Process Monitors: Each boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. Appendix E identifies minimum requirements for monitoring equipment.
5. Control Equipment: Each boiler shall be equipped with:
   - Low-NOx natural gas burners rated for no more than 0.15 pounds of NOx per MMBtu of heat input. Four burners are installed with one in each corner the boiler. The maximum heat input rate from all four burners is ~~400~~ 605 MMBtu per hour.
   - Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
   - An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.

- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx.
- A carbon injection system (or equivalent) for potential control of mercury emissions.

6. Continuous Monitors: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), opacity, oxygen (O_2), and sulfur dioxide (SO_2) in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. Appendix E identifies minimum requirements for monitoring systems.

7. Good Combustion Practices: 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 optimize air/fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator shall provide sufficient excess air to ensure good combustion within the boiler. The application to revise the Title V operation permit shall identify "good combustion practices" for the cogeneration boilers to minimize pollutant emissions during startup, operation, and shutdown. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. Good combustion controls shall also include the following:
   - Maintain improved combustion controls to provide efficient tuning of air/fuel control instrumentation.
   - Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
   - Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
   - Mix biomass fuel to provide a consistent fuel blend.
   - Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
   - When necessary to enhance poor combustion, reduce the biomass feed rate below the maximum rate.
   - When necessary to enhance poor combustion, co-fire natural gas or distillate oil.

8. O&M Plans: The application to revise the Title V operation permit shall include an operation and maintenance plan consisting of at least the following items.
   a. For the cogeneration boilers, electrostatic precipitators (ESP), selective non-catalytic reduction (SNCR) systems, activated carbon injection (ACI) mercury control systems, and silo fabric filters, identify: the capacities, design efficiencies, pollutant emission rates, general operational description of equipment, key design and operating parameters, expected operating range of each key parameter, monitoring of key parameters, frequency of monitoring (instantaneous, continual, or continuous), and actions taken to return key parameters to within the expected operating ranges. The plan shall also specify good operating practices to promote efficient boiler combustion, startup and shutdown procedures for the boilers and control systems to minimize emissions, and precautions to prevent fugitive particulate matter emissions. *{Permitting Note: Operation outside of the specified operating range for any monitored parameter would not be a violation by itself. However, continued operation outside of a specified operating range without corrective action may be considered circumvention of the air pollution control equipment or methods.}*
   b. For the selective non-catalytic reduction (SNCR) systems identify an alternate NOx emissions control plan based on previous monitoring data that shall be implemented in case the NOx monitoring system is down. The plan shall identify the minimum urea injection rate that has demonstrated continuous compliance with the NOx emissions standard at various load conditions.

9. Materials Handling Controls: 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 an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust.
   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 discharging to the disposal bin.

OPERATIONAL RESTRICTIONS

10. Permitted Capacity: The cogeneration boilers shall be constructed and operated in accordance with the capabilities and specifications described in the application. The maximum heat input rate to each cogeneration boiler shall not exceed ~~715~~ 760 MMBtu/hr when burning 100 percent biomass, ~~400~~ 605 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent very low sulfur distillate oil. ~~The maximum heat input to the entire plant (total for all three boilers combined) shall not exceed 11.5 x 10+6 MMBtu during any consecutive 12-month period.~~ The steam production of each boiler shall not exceed an average of ~~455,418~~ 506,100 pounds per hour at 1,500 psig and 975°F.

11. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant 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 material or similar vegetative matter that has been delivered to the plant 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 material and vegetative matter.

    The permittee shall design and implement a management and testing program for the wood material and other materials delivered to the plant 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. 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. Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. Fuel scheduled for burning shall be inspected daily. At a minimum, the fuel management program shall include the following sampling and analyses:

    a. At least twice each month, the permittee shall have separate analyses conducted on an as-fired wood sample and an as-fired bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), and moisture content (modified ASTM D3173, percent by weight). In addition the wood sample shall be analyzed for copper, chromium, and arsenic in accordance with Methods 3050/6010 (EPA Method SW-846) and reported in ppm by weight, dry. Samples shall be taken at least two weeks apart.

    b. At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash for arsenic, copper, and chromium in accordance with the procedures described in EPA Method SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods* (40 CFR 261, Appendix III). The analytical results from ash testing shall be used in conjunction with those from the as-fired wood samples to evaluate the effectiveness of the fuel management program in removing chemically treated wood from the biomass fuel. The permittee shall dispose of all ash generated on site in accordance with the applicable state and federal regulations.

    c. Analytical results of the as-fired biomass fuels and ash sampling shall be summarized and provided in the quarterly report to the Compliance Authority.

    The ash and fuel management program shall become part of the Title V operation permit.

12. Auxiliary Fuel: The cogeneration boilers shall fire only distillate oil and pipeline natural gas as auxiliary fuels. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05 percent sulfur by weight as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil is oil that has been refined from crude oil and that has not been used in any manner that may contaminate it. Each boiler may startup solely on pipeline natural gas or distillate oil.

13. Fossil Fuel Limitation: The firing of fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter.

14. Fuel Records: The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log.

15. ~~Emergency Standby: The existing sugar mill boilers shall comply with the following requirements.~~Permanent Shutdown: Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall remain permanently shutdown and rendered incapable of operation. {Permitting Note: Okeelanta Corporation's Boiler No. 16 may operate in accordance with modified Permit No. PSD-FL-169(A).} [Rule 62-212.400, F.A.C.]

    ~~a. Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 may be retained for emergency standby operation until April 1, 2002. These boilers shall only operate in the event of electrical or mechanical failure of all three of the cogeneration boilers. Simultaneous operation of any of these sugar mill boilers with any of the cogeneration boilers is prohibited. Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall be permanently shutdown and rendered incapable of operation no later than October 1, 2002.~~

    ~~b. Each sugar mill boiler shall comply with its most recent air construction and operation permit, including all emissions performance, testing, and monitoring requirements as well as any applicable Alternate Sampling Procedures approved by the Department. The sugar mill boilers shall only fire fuels approved in the most recent permits.~~

~~16. Auxiliary Boiler: Sugar mill boiler No. 16 shall be operated in accordance with revised Permit No. PSD-FL-169A and the subsequently revised Title V operation permit.~~

EMISSIONS LIMITING STANDARDS

~~17.~~16. Emissions Standards: Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

Pollutant	Averaging Period	Emissions Standards per Boiler [h]	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO) [a]	30-day rolling CEMS avg.	0.50	~~357.5~~380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) [b]	30-day rolling CEMS avg.	0.15	~~107.3~~114.0
Sulfur Dioxide (SO_2) [c]	24-hour rolling CEMS avg.	0.20	~~143.0~~152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity [d]	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM/PM_{10}) [e]	3-run test avg.	~~0.03~~0.026	~~21.5~~19.8
Volatile Organic Compounds (VOC) [f]	3-run test avg.	0.05	~~42.9~~38.0
~~Lead [g]~~	~~3-run test avg.~~	~~1.5×10^{-04}~~	~~NA~~

Mercury ~~h~~g	3-run test avg.	5.4×10^{-06}	NA
~~Lead and~~ Fluorides ~~i~~h	Fluoride emissions shall be minimized by firing biomass as the primary fuel with natural gas and very low sulfur distillate oil as auxiliary fuels. *The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.*		

a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NOx monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. In addition, the CO CEMS shall record CO emissions in terms of "ppmvd corrected to 3% oxygen" for each 1-hour block average and each 24-hour block average (day). *{Permitting Note: CO emissions data recorded and reported in terms of "ppmvd corrected to 3% oxygen" are for informational purposes only.}*

b. Compliance shall be determined by data collected from the required NOx CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and the requirements of 40 CFR 60.13, 60.44a, 60.46a, 60.47a, 60.48a, and 60.49a. A boiler-operating day is any day in which any authorized fuel is fired.

c. Compliance with the SO_2 standards shall be determined by data collected from the required SO_2 CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO_2 hourly averages shall not be excluded from any compliance average. *{Permitting Note: Potential emissions of sulfuric acid mist are minimized by the effective control of SO_2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO_2 emissions.}*

d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations.

e. Compliance with the particulate matter standards shall be determined by the average of three test runs conducted in accordance with EPA Method 5. For purposes of reporting PM_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}.

f. Compliance with the VOC standards shall be determined by the average of three test runs conducted in accordance with EPA Method 25A based on propane. In addition, the permittee may choose to conduct EPA Method 18 concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".

~~g. Compliance with the lead standards shall be determined by the average of three test runs conducted in accordance with EPA Method 12 or 29.~~

~~h.~~g. Compliance with the mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall reactivate the carbon injection system for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

~~i.~~h. *The particulate matter standard is also a surrogate standard for lead emissions. {Permitting Note: For reporting purposes, average lead emissions are expected to be 2.6 x 10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9 x 10^{-04} lb/MMBtu when firing bagasse/wood.}*

~~j.~~i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19. The cogeneration boilers are also subject to the new source performance standards (NSPS Subpart Da) for new electric utility steam generating units. These requirements include the general provisions of Subpart A in 40 CFR 60, as well as the following source-specific applicable requirements: 60.40a (Applicability and Designation of Affected Facility); 60.41a (Definitions); 60.42a (Standards for Particulate Matter); 60.43a (Standard for Sulfur Dioxide); 60.44a (Standard for Nitrogen Oxides); 60.46a (Compliance Provisions); 60.47a (Emissions Monitoring); 60.48a (Compliance Determination Procedures and Methods); and 60.49a (Reporting Requirements). The cogeneration boilers are also subject to Rule 62-296.405(2), F.A.C. (Fossil Fuel Steam Generators with more than 250 MMBtu per Hour of Heat Input), Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment), and Rule 62-296.570, F.A.C. (Reasonably Available Control Technology Requirements for Major VOC and NOx Facilities).

{Permitting Note: Appendix D identifies the final BACT determinations for the cogeneration boilers.}

~~18.~~17. Material Handling: The following conditions apply to the biomass, ash, and activated carbon handling facilities.

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

b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions of no more than 20% opacity are allowed.

c. 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. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

STARTUP, SHUTDOWN, AND MALFUNCTION

~~19.~~18. Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

a. *Definitions*

1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4,

F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 16. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_2 emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]

4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

COMPLIANCE METHODS AND REPORTING

~~20.~~ 19. Stack Test Requirements

a. *Initial Tests*: ~~Within 90 days of the effective date of this permit, the permittee shall conduct compliance tests for emissions of lead,~~ Initial tests were initially required for emissions of mercury, particulate matter, and volatile organic compounds. ~~If conducted within the 12 month period prior to the effective date of this permit, previous emissions tests may be used to demonstrate compliance for these pollutants.~~ The Department may require these initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or pollution control equipment.

b. *Annual Tests*: At least once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

c. *Renewal Tests*: Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of ~~lead~~, mercury, particulate matter, and volatile organic compounds. Tests shall be conducted at five-year intervals.

d. *Test Procedures*: The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix C of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: Compliance with the emission limits specified in this permit 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).

EPA Method*	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
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 emissions
6 or 6C	Sulfur dioxide emissions

7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity *{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}*
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions *{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".*
29	Multiple metals emissions
101A	Particulate and gaseous mercury emissions

No other methods may be used to demonstrate compliance unless prior written approval is received from the Department~~ in accordance with a permit modification or an alternate sampling procedure issued pursuant to 62-297.620, F.A.C~~. Other applicable testing requirements are included in Appendix C of the permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

~~21.~~20. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2 based on data collected from the continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) required for each cogeneration boiler. Appendix E specifies the minimum requirements for monitoring equipment.

~~22.~~21. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in Appendix E of this permit. The permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. The fuel usage summary shall include the monthly heat input and the 12-month rolling total heat input for the cogeneration boilers. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter.

~~23.~~22. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. Along with this report, the permittee shall also submit a summary of CO emissions from each cogeneration boiler in terms of "ppmvd corrected to 3% oxygen based on a 24-hour average (day)" for each operational day. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDICES

CONTENTS

CITATION FORMAT

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

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

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

"2222" represents the specific facility ID number

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

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

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

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

PSD Permit Numbers

Example: Permit No. PSD-FL-317

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

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

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13. This permit also constitutes:

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

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

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

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

STANDARD REQUIREMENTS

{Permitting Note: Unless otherwise specified by permit, the following conditions are generally applicable to all emissions units.}

EMISSIONS AND CONTROLS

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

2. <u>Circumvention</u>: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. <u>Excess Emissions Prohibited</u>: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F,A.C.]

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

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

6. <u>Objectionable Odor Prohibited</u>: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

7. <u>General Visible Emissions</u>: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

8. <u>Unconfined Particulate Emissions</u>: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

9. <u>Operating Rate During Testing</u>: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

10. <u>Calculation of Emission Rate</u>: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

11. <u>Test Procedures</u>: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

12. Determination of Process Variables

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

13. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

14. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

15. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

16. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

17. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

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

PSD Applicability

The existing facility is located in Palm Beach County, an area that is in attainment with (or designated as unclassifiable for) all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The cogeneration plant is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Potential emissions from the plant are greater than 100 tons per year for at least one regulated pollutant. As such, the facility is "major" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project will result in net emissions increases that are greater than the PSD significant emission rates identified in Table 62-212.400-2, F.A.C. for the following pollutants: carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, volatile organic compounds, lead, fluorides, and sulfuric acid mist. Therefore, the project is subject to PSD review and the Department makes the following determinations of Best Available Control Technology (BACT) for these pollutants.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department determines that the following standards represent the Best Available Control Technology (BACT) for the existing biomass-fired cogeneration boilers.

Pollutant	BACT Standards for Each Cogeneration Boiler		
	Averaging Period	**lb/MMBtu**	**lb/hr**
Carbon Monoxide (CO) *Based on "good combustion practices".*	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NOx) *Based on the application of SNCR.*	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2) *Based on "low sulfur fuels". The SO_2 standards are also surrogate standards for sulfuric acid mist (SAM) emissions.*	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Opacity *Based on application of mechanical dust collectors and electrostatic precipitator.*	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM) *Based on application of mechanical dust collectors and electrostatic precipitator.*	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC) *Based on "good combustion practices".*	3-run test avg.	0.05	38.0
Lead (Pb) and Fluorides (Fl) *Based on "low lead/fluoride fuels".*	BACT is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators. The particulate matter standard shall also serve as a surrogate standard for lead.		

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for this project.

Determination By:

(DRAFT)

Jeff Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Michael G. Cooke, Director (Date)
Division of Air Resources Management

CONTINUOUS MONITOR REQUIREMENTS

{Permitting Note: The following summarizes the basic monitoring requirements for the cogeneration boilers.}

1. Process and Control Parameters: The permittee shall install, calibrate, maintain, and operate continuous monitoring systems to measure and record the following process and control equipment parameters:

   a. *Power Output.* The net power generation (MW) delivered for sale to the electrical power grid shall be continuously monitored and recorded in 1-hour block averages.

   b. *Fuel Feed Rate.* Fuel flow meters equipped with totalizers are required to monitor and record the fuel feed rates for distillate oil (gallons) and natural gas (million cubic feet). Biomass feed rates (tons of bagasse and tons of wood) shall be calculated and recorded based on actual fuel flows. The permittee shall continuously monitor the fuel throughput rates based on the fuel flow monitors and calculate the actual heat input rates (24 hour average) for each fuel during each day of operation.

   c. *Steam Parameters.* Each cogeneration boiler shall be equipped with monitors to measure and record the steam temperature (° F), steam pressure (psig), and steam production (pounds).

   d. *Urea Injection Rate (SNCR System).* The urea injection rate shall be continuously monitored and recorded for each cogeneration boiler. The urea injection rate shall be compared to actual NOx emissions data recorded by the CEMS. The permittee shall identify minimum urea injection rates for various load conditions that ensure compliance with the NOx standards. Should the NOx CEMS be unavailable, the urea injection rate shall be maintained at an appropriate minimum level.

   e. *Activated Carbon Injection Rate (Mercury Control System).* If the mercury injection system is reactivated, the carbon injection rate shall be continuously monitored and recorded. Based on the testing required in this permit, the permittee shall identify and maintain minimum carbon injection rates to ensure effective control of mercury emissions.

   The permittee shall maintain written procedures for inspecting, calibrating, and maintaining the process and control monitoring equipment. [Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

2. CEMS and COMS: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) and continuous opacity monitors (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), oxygen (O_2), sulfur dioxide (SO_2), and opacity in a manner sufficient to demonstrate compliance with the standards of this permit.

   a. *Performance Specifications.* Each monitor shall be located in the ductwork between the electrostatic precipitator and the stack (or in the stack) to obtain emissions measurements representative of actual stack emissions. Each CEMS and COMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements.

      (1) Opacity shall comply with Performance Specification 1 in Appendix B of 40 CFR 60.

      (2) NOx and SO_2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO_2 reference method for the annual RATA shall be EPA Method 6 (or 6C) in Appendix A of 40 CFR 60. The NOx reference method for the annual RATA shall be EPA Method 7 (or 7E) in Appendix A of 40 CFR 60.

      (3) O_2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O_2 reference method for the annual RATA shall be EPA Method 3A Appendix A of 40 CFR 60.

      (4) CO CEMS shall meet Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The CO reference method for the annual RATA shall be EPA Method 10 in Appendix A of 40 CFR 60.

   b. *Data Collection.* Each CEMS and COMS shall record emissions data at all times including episodes of startup, shutdown, and malfunction. Emissions data recorded during periods of startup, shutdown, or malfunction may only be excluded from the compliance averages in accordance with the requirements specified in Section III of this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions.

      Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period. Each 1-hour average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. CO, NOx, and SO_2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". O_2 CEMS shall express the 1-hour emission average in terms of "percent by volume". A 30-day rolling emission average shall be the average of all valid 1-hour emission averages collected during the 30-day period. A 12-month rolling emission average shall be the average of all valid 1-hour emission averages collected during the 12-month period. NOx and SO_2 CEMS shall comply with NSPS Subpart Da in 40 CFR 60.

Each COMS shall be designed and operated to complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. Opacity shall be recorded in 6-minute block averages.

c. *Quality Assurance Procedures*. Each CEMS shall comply with the applicable quality assurance procedures specified in Appendix F of 40 CFR 60. These procedures include methods such as calibration, calibration drift, data recording, accuracy assessment, calculations, audit procedures, preventive maintenance, corrective actions, and reporting.

d. *Monitor Availability*. Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

e. *Other Applicable Requirements*: Each CEMS shall comply with the following applicable requirements Rules 62-204.800 and 62-297.520, F.A.C. (Continuous Monitor Performance Specifications); 40 CFR 60.13 (Subpart A - Monitoring Requirements); 40 CFR 60.47a (Subpart Da - Emissions Monitoring); 40 CFR 60.48a (Subpart Da - Compliance Determination Procedures and Methods); 60.49a (Subpart Da - Reporting Requirements).

f. *Quarterly Reports*: For each cogeneration boiler, the permittee shall submit the report on the following page to summarize each required continuous emissions and opacity monitoring system. The authorized representative shall certify that the information provided in each quarterly report is true, accurate, and complete to the best of his/her knowledge. Each quarterly report is due no later than 30 days following the calendar quarter.

CONTINUOUS MONITOR REQUIREMENTS

Facility Name Okeelanta Cogeneration Plant	**ARMS ID No.** 0990332	**Title V Air Permit No.**
Facility Address/Location Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida		
Emissions Unit Description Spreader stoker boiler with maximum heat input of 760 MMBtu/hour ARMS EU ID No. ______ Cogeneration Boiler: ___ A ___ B ___ C	**Unit Operation in Calendar Quarter** ________ hours	
Control Equipment Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators		
Primary Fuel Biomass, which includes bagasse from adjacent sugar mill and wood material from area suppliers (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)	**Auxiliary Fuels** Pipeline natural gas Distillate oil (≤ 0.05% sulfur by weight)	
Pollutant Monitored ***(Check one.)*** _____ CO _____ NOx _____ SO2 _____ Opacity	**Calendar Quarter of Operation Covered** ***(Check one.)*** ___ 1 ___ 2 ___ 3 ___ 4 for year ________	
Continuous Monitor Information Manufacturer: ______________________ Model No. ______________________ Date of last certification or audit: ______________	**Emission Standards** ______ lb/MMBtu of heat input, 24-hour rolling average ______ lb/MMBtu of heat input, 30-day rolling average ______ lb/MMBtu of heat input, 12-month rolling average ≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Emission Data Summary 1. Duration of excess emissions in reporting period due to: a. Startup/shutdown .... _____ b. Control equipment problems .... _____ c. Process problems .... _____ d. Other known causes .... _____ e. Unknown causes .... _____ 2. Total duration of excess emissions .... _____ 3. [Total duration of excess emissions] x (100%) .... _____ [Total source operating time] *Note: Report "excess emissions" as emission averages that are in excess of a permitted emissions standard. For gases, report excess emissions in terms of hours. For opacity, report excess emissions in terms of minutes.*	**CMS Performance Summary** 1. CMS downtime in reporting period due to: a. Monitor Equipment Malfunctions .... _____ b. Non-Monitor Equipment Malfunctions .... _____ c. Quality Assurance Calibration .... _____ d. Other Known Causes .... _____ e. Unknown Causes .... _____ 2. Total CMS Downtime .... _____ 3. [Total CMS Downtime] x (100%) .... _____ [Total source operating time] *If monitor availability is not at least 95%, provide a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability*	
Emissions Data Exclusion 1. Report the number of 1-hour emissions averages excluded the reporting period due to: a. Startup .... _____ b. Shutdown .... _____ c. Malfunction .... _____ d. Total .... _____ 2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken. 3. On a separate page, describe any changes to CMS, process or controls during last quarter.		