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. Ricardo Lima
Vice President & General Mgr.
Okeelanta Corporation
21250 U.S. Highway 27
South Bay, FL 33493

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. MCPHEE B. Date of Delivery 9/27/01

C. Signature X B McPh

☐ 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.

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

U.S. Postal Service
CERTIFIED MAIL RECEIPT
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Mr. Ricardo Lima, VP & Gen. Mgr.

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
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Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
Okeelanta Corp.
Street, Apt. No., or PO Box No.
21250 US Highway 27
City, State, ZIP+4
South Bay, FL 33493

PS Form 3800, February 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 20, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ricardo Lima, Vice President and General Manager
Okeelanta Corporation
21250 U.S. Highway 27
South Bay, FL 33493

Re: Project No. 0990005-009-AC
Revised Draft Permit No. PSD-FL-169A
Okeelanta Corporation's Sugar Mill and Refinery
Conversion of Boiler No. 16 to Natural Gas

Dear Mr. Lima:

Enclosed is one copy of the Revised Draft Permit to modify existing Boiler No. 16 at Okeelanta Corporation's sugar mill and refinery located approximately six miles south of South Bay on U.S. Highway 27 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 Department retracts the previous draft permit package issued on June 4, 2001.

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 Al 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,

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

CHF/AAl/jfk

Enclosures

In the Matter of an
Application for Air Permit by:

Okeelanta Corporation
21250 U.S. Highway 27
South Bay, FL 33493

Authorized Representative:
Mr. Ricardo Lima, Vice President and General Manager

Okeelanta Sugar Mill and Refinery
Project No. 0990005-009-AC
Revised Draft Permit No. PSD-FL-169A
Boiler No. 16, Natural Gas Modification
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, Okeelanta Corporation, applied on March 23, 2001 to the Department for an air construction permit to modify existing mill Boiler No. 16 to accommodate natural gas as a fuel. The boiler is part of Okeelanta Corporation's existing sugar mill and refinery located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The Draft Permit authorizes the modification of the boiler's burner system to incorporate low NOx burners with flue gas recirculation to fire natural gas and very low sulfur distillate oil. The Department retracts the previous draft permit package issued on June 4, 2001.

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 is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, 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.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9/25/01 to the persons listed:

Mr. Ricardo Lima, Okeelanta Corp.*
Mr. Matthew Capone, Okeelanta Corp.
Mr. James Meriwether, Okeelanta Power
Mr. David Buff, Golder Associates
Mr. James Stormer, PBCHD
Mr. Ron Blackburn, SED
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 9/25/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 0990005-009-AC
Draft Permit PSD-FL-169A

Okeelanta Corporation
Modification of Existing Mill Boiler No. 16
Emissions Unit No. 014

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Okeelanta Corporation to modify existing Boiler No. 16. This boiler is part of Okeelanta Corporation's sugar mill and refinery located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. Okeelanta Corporation's authorized representative is Mr. Ricardo Lima, the Vice President and General Manager, and the mailing address is 21250 U.S. Highway 27, South Bay, FL 33493.

The applicant proposes to modify the existing boiler's burner system to accommodate natural gas and very low sulfur distillate oil as authorized fuels. The following table summarizes the potential annual pollutant emissions from this project.

Pollutant	Annual Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	96	100	No	No
NOx	96	40	Yes	Yes
PM/PM_{10}	22	25/15	Yes	Yes
SO_2	35	40	No	Yes [c]
VOC	28	40	No	No

As shown, determinations of the Best Available Control Technology (BACT) were required for emissions of nitrogen oxides (NOx) and particulate matter (PM_{10}) pursuant to Rule 62-212.400, F.A.C., which is part of the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. BACT determinations were also required for particulate matter (PM) and sulfur dioxide (SO_2) in accordance with Rule 62-296.406, F.A.C., which regulates boilers with a heat input of less than 250 MMBtu per hour. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) are below the PSD significant emission rates. The Department determined BACT to be the efficient combustion of very low sulfur fuels for emissions of PM/PM_{10} and SO_2. BACT for NOx emissions was determined to be the installation of low NOx burners with flue gas recirculation. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) will be minimized by the efficient combustion of clean fuels.

An air quality impact analysis was conducted by the applicant and reviewed by the Department. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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.

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:

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 DETERMINATION
(Including Draft BACT Determinations)

PROJECT

Project No. 0990005-009-AC
Revised Draft Permit No. PSD-FL-169A
Conversion of Mill Boiler No. 16 to Natural Gas
(Emissions Unit No. 014)

COUNTY

Palm Beach County

APPLICANT

Okeelanta Corporation
ARMS Facility ID No. 0990005
Existing Sugar Mill and Refinery

PERMITTING AUTHORITY

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

September 19, 2001

{Filename: Revised 169A BACT and TEPD.DOC}

1. GENERAL PROJECT INFORMATION

1.1 Applicant Name and Address

Okeelanta Corporation
21250 U.S. Highway 27
South Bay, FL 33493

Authorized Representative:
Mr. Ricardo Lima
Vice President and General Manager

1.2 Processing Schedule

03/23/01 Department received the application for a PSD air pollution construction permit; complete.

03/30/01 Department mailed copies to EPA Region 4 and the National Park Service.

06/04/01 Department issued initial draft permit.

1.3 Facility Description and Location

The applicant proposes to modify Boiler No. 16, which is operates at Okeelanta Corporation's existing sugar mill and refinery located approximately six miles south of South Bay on U.S. 27 in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.9 km East, and 2940.1 km North. This is an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The location is approximately 92 km from the nearest Class I area, the Everglades National Park.

1.4 Standard Industrial Classification Code (SIC)

The existing facility consists of two plants. An existing mill processes sugarcane to produce raw and refined sugar. An existing cogeneration plant fires biomass to produce steam for the mill and generate electricity for sale to the power grid. These plants have the following SIC codes.

SIC No. 2061 – Sugar Mill

SIC No. 2062 – Sugar Refinery

SIC No. 4911 – Electric Generation

1.5 Regulatory Categories

Title III: Based on the application, the facility is a major source of hazardous air pollutants (HAP).

Title IV: Based on the Title V permit, the existing facility is not subject to the acid rain provisions of the Clean Air Act.

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

PSD: The facility operates units classified as "fossil fuel steam electric plants with more than 250 mmBTU per hour of heat input", which is one of the 28 PSD source categories with lower thresholds. Because potential emissions are greater than 100 tons per year for at least one regulated air pollutant, the facility is a major source of air pollution in accordance with the requirements of the Prevention of Significant Deterioration (PSD) of Air Quality Program (Rule 62-212.400, F.A.C.). Projects resulting in net emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. are subject to the PSD new source preconstruction review requirements.

NSPS: This project modified a package boiler, which is subject to Subpart Db of the New Source Performance Standards in 40 CFR 60.

1.6 Project Description

The applicant proposes to modify the burner system of existing mill Boiler No. 16 (Emissions Unit No. 014) to accommodate natural gas as the primary fuel and very low sulfur distillate oil as an alternate fuel. The applicant proposes the efficient combustion of clean fuels to minimize emissions of CO, PM/PM_{10}, SO_2, and VOC. The applicant proposes the installation of low NOx burners with flue gas recirculation to reduce NOx emissions.

1.7 Potential Emissions

Table 1A. This table summarizes PSD applicability for this project based on the application.

Pollutant [a]	Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	96	100	No	No
NOx	96	40	Yes	Yes
PM/PM_{10}	22	25/15	Yes	Yes
SO_2	35	40	No	Yes [c]
VOC	28	40	No	No

[a] The application discussed emissions of beryllium, which is no longer a PSD-regulated pollutant.

[b] Potential emissions are based on the requested permit limits and maximum operation. All PM emitted is assumed to be PM_{10}. Applicant assumed zero past actual emissions due to inactivity of boiler over last two years.

[c] Rule 62-296.406, F.A.C. requires PM and SO_2 BACT determinations for boilers with heat inputs of 250 mmBTU per hour or less.

2. APPLICABLE REGULATIONS

2.1 State Regulations

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

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 and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
	Rule 62-296.406 – Fossil Fuel Steam Generations with Less Than 250 mmBTU per Hour of Heat Input
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

2.2 Federal Regulations

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

Title 40, CFR	Description
Section 51.166	Requirements for State Implementation Plans, Prevention of Significant Deterioration
Section 52.21	Approval of State Implementation Plans, Prevention of Significant Deterioration
Part 60	Subpart A - General Provisions for NSPS Sources
	NSPS Subpart Db - Stationary Gas Turbines
	Applicable Appendices

2.3 General PSD Applicability

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

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

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants

2.4 PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to predict ambient impacts from the project; a comparison of predicted ambient impacts from the project with National Ambient Air Quality Standards and PSD Increments; an evaluation of the air quality impacts from the project upon soils, vegetation, wildlife, and visibility; and an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The purpose of the Air Quality Analysis is to determine whether or not the proposed project will have a significant impact on Class I and Class II Areas and determine whether or not emissions from the project contribute significantly to, or cause a violation of, any state or federal ambient air quality standards.

The second part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of the PSD Significant Emission Rates. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination 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 such 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 shall 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 policy for pollution prevention.

2.5 PSD Applicability for Project

The proposed project is located in Palm Beach County, Florida, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). As previously discussed, the facility is an existing PSD-major source and is subject to the new source preconstruction review requirements. BACT determinations are required for NOx, and PM_{10} because potential emissions of these pollutants exceed the PSD Significant Emission Rates in Table 62-212.400-2. BACT determinations are also required for PM and SO_2 in accordance with Rule 62-296.406, F.A.C. The Department is required to make BACT determinations for these pollutants and review the applicant's air quality impact analysis.

3. DRAFT BACT DETERMINATIONS

3.1 Available Information

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

- Informal comments received from the National Park Service;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- Emissions guarantees from Coen for the low-NOx burners;
- Actual emissions test results for existing Boiler No. 16 when firing distillate oil containing 0.3% sulfur by weight.
- BACT Clearinghouse Web Site for the California Air Resources Bureau;

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. A list of recent determinations regarding similar projects in the United States is provided in the following table.

Table 3A. Summary of Recent CO and NOx BACT Standards
Boilers and Heaters, ≈ 200 mmBTU per Hour of Heat Input

Facility	RBLC ID	Permit Date	Capacity mmBTU/hr	CO Emissions lb/mmBTU	NOx Emissions lb/mmBTU	Controls
Alabama Power Co.	AL-0128	03/99	220	0.165, gas	0.053, gas	LNB w/FGR
American Soda LLP	CO-0040	05/99	81	0.09, gas	0.050, gas	LNB System
Cargill-Eddyville	IA-0050	04/99	182	NA	0.050, gas	LNB w/FGR
Champion International	FL-0217	06/99	≈ 50	0.18, gas	0.10, gas	LNB System
Conoco, Heater (H-24)	LA-0119	8/99	264	0.08, gas	0.06, gas	LNB System
Conoco, Heater (H-1103)	LA-0119	8/99	100	0.08, gas	0.06, gas	LNB System
Conoco, Heater (H-20002)	LA-0119	8/99	150	0.08, gas	0.03, gas	LNB System
Conoco, Heater (H-40001)	LA-0119	8/99	237	0.08, gas	0.03, gas	LNB System
McCaine Food, Inc.	ME-0017	12/98	99	0.16, res. oil	0.30, res. oil	LNB w/FGR
Mid-Georgia Cogen.	GA-0063	04/96	60	0.05, gas	0.10, gas	LNB w/FGR
Mid-Georgia Cogen.	GA-0063	04/96	60	0.09, oil	0.15, oil	LNB w/FGR
Occidental Chemical	LA-0118	03/99	355	0.08, gas	0.08, gas	LNB System
Rayonier, Inc.	FL-0182	09/98	212	NA	0.425, res. oil	LNB w/FGR (Note: temporary boiler)

Notes: Information was compiled from EPA's RACT, BACT, LAER Clearinghouse Database for similarly sized boilers firing natural gas or oil and permitted in 1996 or later.

3.2 Nitrogen Oxides (NOx)

Discussion of NOx Emissions

Emissions of NOx are a result of the thermal fixation nitrogen in the combustion air (thermal NOx) and the oxidation of nitrogen in the fuel (fuel NOx). *Thermal NOx* is primarily a function of peak flame temperature and available oxygen, which are factors that depend on boiler size, firing configuration, and operating practices. *Fuel NOx* is a function of nitrogen in the fuel and the available oxygen. About 50% of the fuel nitrogen is converted to NOx, which means that fuel NOx emissions from firing natural gas or distillate oil is almost negligible because these fuels contain only trace amounts of fuel-bound nitrogen.

Description of Available NOx Controls

The following technologies were identified as potentially applicable for the control of NOx from boilers firing natural gas and distillate oil.

Low NOx burners with Flue Gas Recirculation (LNB w/FGR): The following description is an excerpt from the July 1998 edition of Section 1.4.4 in AP-42.

"The two most prevalent combustion control techniques used to reduce NOx emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NOx burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NOx emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NOx mechanism. To a lesser extent, FGR also reduces NOx formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NOx emission rates for these systems. An FGR system is normally used in combination with specially designed low NOx burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low

NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent.

Low NOx burners reduce NOx by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NOx formation. The two most common types of low NOx burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners."

Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between approximately 450° F and 850° F. SCR is a commercially available and demonstrated control technology with numerous applications nationwide. Conventional SCR is technically feasible for this project with a control efficiency of approximately 75% to 85%.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. The exhaust temperature must typically be maintained above 1600°F to allow the reaction to occur; otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. Also, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. New catalysts are available that can extend this temperature range to approximately 1000° F to 1950° F. For boilers, SNCR has achieved control efficiencies in the 25% to 75% range and is technically feasible for this project.

SCONOx™: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and distributed by ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which requires a heat recovery steam generator for use with a combined cycle gas turbine. SCONOx™ can achieve a control efficiency greater than 90% and is technically feasible for this project.

Cannon Technology's Low Temperature Oxidation (LTO): This technology involves injecting ozone into a gas stream (approximately 300° F) to oxidize CO, NOx, and SO_2 to carbonates, nitrates, and sulfates, which are then absorbed by a dilute nitric acid solution in a scrubber. The system was developed for steam boilers and test results show NOx emissions below 4 ppmvd at 3% oxygen for gas firing. However, only very small units (< 20 mmBTU per hour) have been tested. Because the exhaust gas will be approximately 400° F and the modified boiler is nearly ten times that of the largest tested unit with LTO, this technology was not evaluated further.

Applicant's Proposed NOx Controls

The applicant ranked the control technologies in the following order:

Rank	Technology	Control Effciency (%)	Emissions Rate (lb/mmBTU) [c]	Annual Emissions TPY
1	SCR and LNB w/FGR [a]	92%	0.03	22.8
2	SNCR and LNB w/FGR [b]	72%	0.105	79.6
3	LNB w/FGR	60%	0.15	113.8
Base	Existing Boiler No. 16	Base	0.135 [d]	121.2

[a] - SCR alone can achieve approximately 80% reduction.

[b] - SNCR alone can achieve approximately 30% reduction.

[c] - Emissions rate for oil firing. NOx limit is 0.18 lb/mmBTU.

[d] - Based on actual average emissions from Boiler No. 16.

The applicant states that SCR and SNCR would result in the following adverse impacts.

Energy Impacts: The applicant states that installation of SCR would result in energy penalties due to the pressure drop across the catalyst, energy required to operate the ammonia injection system, and possibly energy to reheat the exhaust gas. Similarly, SNCR would result in energy penalties to operate the system.

Environmental Impacts: The applicant indicates that installation of SCR would result in unreacted ammonia "slipping" past the catalyst, potential ammonia emissions from an accidental release, and solid waste disposal of the spent catalyst. Similarly, SNCR could result in urea emissions from an accidental release.

Economic Impacts: The applicant estimates that the installation of SCR would result in a capital cost of $2.8 million, and annualized cost of $686,807, and a cost effectiveness of $7546 per ton of NOx removed. The applicant estimates that the installation of SNCR would result in a capital cost of $950,000, and annualized cost of $282,011, and a cost effectiveness of $8263 per ton of NOx removed.

Applicant's Proposal: Based on the estimated high capital and operating costs associated with the add on control systems, the applicant rejected both SCR and SNCR and proposes the following NOx standards based on LNB with FGR:

Gas: NOx emissions shall not exceed 0.055 lb/mmBTU of heat input

Oil: NOx emissions shall not exceed 0.15 lb/mmBTU of heat input

Department's Draft NOx BACT Determination

The Department does not necessarily endorse the applicant's cost evaluations, but generally agrees that neither SCR nor SNCR are cost effective for this project, which consists of a burner system modification to fire natural gas. It is noted that the costs of a SCONOx™ system were not estimated. However, costs for a comparable SCONOx™ system are typically higher than SCR and it is not expected that this technology would be cost effective for the project.

Draft NOx BACT Determination: The Department determines NOx BACT to be low-NOx burners with flue gas recirculation. The following limits represent BACT for NOx emissions.

Gas: NOx emissions shall not exceed 0.10 lb/mmBTU of heat input, 24-hour block CEMS average
NOx emissions shall not exceed 0.06 lb/mmBTU of heat input, 30-day rolling CEMS average

Oil: NOx emissions shall not exceed 0.20 lb/mmBTU of heat input, 24-hour block CEMS average
NOx emissions shall not exceed 0.12 lb/mmBTU of heat input, 30-day rolling CEMS average

As shown in Table 3A, this determination is consistent with recent BACT determinations for similarly sized boilers. The NOx limit for firing natural gas was rounded up because a shorter compliance averaging period than requested was specified. The result is a less than 10% increase. The NOx limit for firing distillate oil was based on the proposed burner manufacturer's guarantee, assuming that the fuel nitrogen content will be less than 0.02% by weight. Recent data on very low sulfur No. 2 distillate oil indicates a *maximum* nitrogen content of 0.015% by weight. Compliance will be demonstrated by data collected from the certified NOx continuous emissions monitoring system (CEMS). In making this determination, the Department gave consideration to the project as a modification of an existing oil-fired boiler to accommodate natural gas as a primary fuel. The draft BACT standards are much more stringent than the NSPS standards in Subpart Db of 40 CFR 60. *Note: This is a revision of the initial determination made in the initial draft permit (06/04/01).*

3.3 Carbon Monoxide CO

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion. In general, CO emissions are inversely proportional to NOx emissions. However, new advanced burner designs have also been able to lower CO emissions concurrently with reduced NOx emissions.

Applicant's Initial Proposed CO Controls

The applicant reviewed recent CO BACT determinations and noted that no add-on controls were required for similarly sized package boilers. In addition, the applicant believes that the proposed emission standards are within the general range of these recent BACT determinations.

Applicant's Initial Proposal: The applicant proposed the following CO standards.

Gas: CO emissions shall not exceed 0.15 lb/mmBTU of heat input

Oil: CO emissions shall not exceed 0.16 lb/mmBTU of heat input

Department's CO Determination

The Department discussed the feasibility of lower CO emissions rates for the modified boiler with the applicant. After additional discussions with the burner manufacturer, the applicant agreed to the following CO emissions standards that would avoid a BACT determination.

Gas: CO emissions shall not exceed 0.10 lb/mmBTU of heat input, 3-hour test average

Oil: CO emissions shall not exceed 0.11 lb/mmBTU of heat input, 3-hour test average

The Department believes that a new boiler would be able to achieve a CO standard of 0.06 to 0.10 lb/mmBTU. The requested emissions standard appears reasonable, considering that the applicant's primary purpose in retrofitting the existing boiler's burner system was to accommodate natural gas as an additional fuel. Compliance with the emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 10 at permitted capacity.

3.4 Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2)

Discussion of PM/PM_{10} and SO_2

Emissions of particulate matter (PM/PM_{10}) and sulfur dioxide (SO_2) will result from the combustion of natural gas and distillate oil. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas and very low sulfur distillate oil contain little ash, sulfur, or other contaminants.

Applicant's Proposed PM/PM_{10} and SO_2 Controls

The applicant indicates that post-control devices are not typically applied to package boilers and would be cost prohibitive.

Applicant's Proposal: For both PM/PM_{10} and SO_2, the applicant proposes the following fuel specifications and opacity standard.

Gas: Pipeline-quality natural gas

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

Gas or Oil: Opacity shall not exceed 20%, except for one 6-minute period per hour not to exceed 27%

Department's Draft PM/PM_{10} and SO_2 BACT Determinations

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. However, particulate emissions are estimated to be much less than 0.01 grains per dscf of exhaust gas, which is approximately the level of controlled emissions from a baghouse. Similarly, there is acid gas scrubbing equipment available to further reduce SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas and very low sulfur distillate oil as the primary fuels with as a backup fuel. The Department agrees with the applicant that further control of particulate matter and sulfur dioxide emissions with any of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS Subpart Db standard of 0.5% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case.

Draft PM/PM$_{10}$ and SO$_2$ BACT Determinations: The Department establishes the following fuel specifications as BACT for PM/PM$_{10}$ and SO_2.

Gas: Pipeline-quality natural gas with a maximum sulfur content of 2 grains of sulfur per 100 SCF

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

The Department notes that pipeline-quality natural gas typically contains much less than 0.5 grains per 100 SCF of natural gas. Compliance with the fuel sulfur limit for distillate oil shall be demonstrated by an initial test and maintaining the fuel quality records provided by the vendor for each shipment. Limiting the fuel sulfur content also effectively limits the potential emissions of SAM and SO_2, so that additional emissions standards are unnecessary. In conjunction with the above fuel specifications, the Department also establishes the following standards as BACT for PM/PM$_{10}$.

Gas or Oil: Opacity shall not exceed 10%, except for one 6-minute period per hour not to exceed 27

Compliance with the opacity standard will be demonstrated by data collected from the required continuous opacity monitoring system (COMS). Note: The applicant requested a higher opacity standard based on the requirements in NSPS Subpart Db. However, that standard was based on firing distillate oil containing up to 0.5% sulfur by weight. The proposed fuels are natural gas and distillate oil containing no more than 0.05% by weight. It is expected that there will be no visible emissions plume from the stack because these fuels contain very little sulfur, ash, or other contaminants. After the initial performance test, the opacity standard will also serve as an indicator of efficient combustion and compliance with the particulate matter standards. *Note: This is a revision of the initial determination made in the initial draft permit (06/04/01).*

3.5 PSD-Synthetic Minor Limits for Volatile Organic Compounds (VOC)

VOC emissions result from incomplete combustion when firing natural gas or distillate oil. The package boiler offers relatively high temperatures for the efficient combustion of the clean fuels, which results in low VOC emissions. Based on the applicant's request, the Department establishes the following standard as a PSD-synthetic minor limit for VOC emissions.

Gas or Oil: the efficient combustion of clean fuels

Compliance with the CO standards and opacity limits shall serve as indicators of good combustion. The maximum expected VOC emission rate will be identified as 0.03 lb/mmBTU of heat input for either fuel. No performance tests will be required, however, the Department reserves the right to require special compliance tests in accordance with Rule 62-297.310(7)(b), F.A.C. VOC emissions should be reported in terms of methane, as determined by EPA Method 25A. Optionally, EPA Method 18 may also be conducted concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane.

3.6 Startup, Shutdown and Malfunction Plan: In accordance with Rule 62-210.700(5), F.A.C., the following permit conditions define alternate opacity standards and allow the exclusion of NOx monitoring data during specified periods of startup, shutdown, and unavoidable malfunction. These conditions shall only apply if operators employ the best operational practices to minimize the amount and duration of emissions during these incidents.

a. *Visible Emissions*: Opacity shall be recorded by the COMS during all episodes of startup, shutdown and malfunction. During startup and shutdown, visible emissions shall not exceed 20% opacity except for one 6-minute period per hour that does not exceed 27% opacity, based on a 6-minute average.

b. *CEM System Data Exclusion*: NOx emissions data shall be recorded by the CEMS during all episodes of startup, shutdown and malfunction. Individual hourly average NOx emission rate values may be excluded from the continuous NOx compliance determinations due to startups, shutdowns, or unavoidable malfunctions. No more than two (2) hourly average emission rate values shall be excluded in any 24-hour period (block or daily) due to all such episodes.

c. *Notification*: Within three days of recording emissions in excess of a standard, the permittee shall notify the Compliance Authority by telephone or facsimile.

These conditions are established in place of the provisions specified in Rule 62-210.700(1), F.A.C. *Note: This is a revision of the initial determination made in the initial draft permit (06/04/01).*

4. AIR QUALITY IMPACT ANALYSIS

4.1 Introduction

The applicant predicts the proposed project will increase PM_{10}, NO_2 and CO emissions at levels in excess of PSD significant amounts. PM_{10} and NO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. The applicant's initial Class II PM_{10}, NO_2, and CO analyses predicted no significant impacts in the area surrounding the proposed facility; therefore, full impact Class II AAQS and PSD Class II increment analyses were not required for these pollutants. The nearest Class I area is the Everglades National Park (ENP) which is located approximately 92 km south of the project site. The applicant's PSD Class I air quality analyses showed no significant impacts; therefore cumulative impact analyses were not required in these Class I areas. Also, the maximum predicted impacts for all four pollutants were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality impact analyses required by the PSD regulations for this project include:

- A Class II significant impact analysis for PM_{10}, NO_2, and CO;
- A Class I significant impact analysis for PM_{10} and NO_2;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

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." A discussion of the required analyses follows.

4.2 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. The table below shows that predicted impacts from the combustion turbines are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Maximum Project Air Quality Impacts Compared to De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
NO_2	Annual	0.5	14	No
CO	8-hour	20	575	No
PM_{10}	24-hour	1	10	No

4.3 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 occur 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 entire PSD Class I Everglades National Park (ENP) area is greater than 50 km from the proposed project, long-range transport modeling was also 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 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 that is approximately 470 km in the north-south direction by 450 km in the east-west direction. The southwest corner is the origin of the modeling domain and is located at 23.75 N degrees latitude and 83.5 W longitude. This modeling domain was produced by utilizing 1990 meteorological data from 3 sea surface, 3 upper air, 8 land surface, and 23 precipitation stations located throughout Florida and adjacent waters.

4.4 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 500 receptors were placed along the facility's restricted property line and out to 10 km from the facility, which is located in a PSD Class II area. This grid had both discrete and gridded polar receptors. The number of discrete receptors was 393. These receptors were spaced at 100-meter intervals along the property boundary. The other 114 receptors were included in a polar grid, with 36 radials extending out from the origin. Along each radial, receptors were located at distances of 4.0, 5.0, 7.0 and 10 km from the origin. There were 126 receptors were placed in the Everglades National Park (ENP) PSD Class I area. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts 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 Air Quality Impacts from the Project Compared 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	0.1	1	No	----
	24-hr	1	5	No	----
CO	8-hr	20	500	No	----
	1-hr	40	2,000	No	----
NO_2	Annual	0.5	1	No	----

Maximum Air Quality Impacts from the Project Compared to the PSD Class I Significant Impact Levels for the Everglades National Park

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.001	0.2	No
	24-hr	0.02	0.3	No
NO_2	Annual	0.001	0.1	No

As shown in the tables there are no maximum predicted air quality impacts due to any emissions from the proposed project which are greater than the PSD significant impact levels. Therefore, under the PSD program, no further air quality impact analysis (PSD increment or AAQS analysis) is required for this project.

4.5 Additional Impacts Analysis

Impacts On Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM_{10}, NO_2 and CO 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 ENP Class I area. This analysis showed no significant impact on visibility in this area.

Growth-Related Air Quality Impacts

There will be no growth associated with this project because equipment is only being replaced.

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 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.

REVISED DRAFT PERMIT

PERMITTEE:

Okeelanta Corporation
21250 U.S. Highway 27
South Bay, FL 33493

Authorized Representative:
Mr. Ricardo Lima
Vice President and General Manager

Okeelanta Sugar Mill and Refinery
Facility ID No. 0990005
Emissions Unit No. 014 (Boiler No. 16)

Project No. 0990005-009-AC
Air Permit No. PSD-FL-169A
Expires: July 1, 2003

PROJECT AND LOCATION

The project is associated with Okeelanta Corporation's existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) located approximately six miles south of South Bay on U.S. Highway 27 in Palm Beach County, Florida. The UTM coordinates are Zone 17, 524.9 km East, and 2940.1 km North. This permit authorizes modification of the burner system on existing Boiler No. 16 that will allow the firing of natural gas and very low sulfur distillate oil.

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 install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(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. Okeelanta Power L.P. operates a cogeneration plant that provides process steam for the sugar mill and refinery and generates electricity for sale to the power grid (SIC 4911).

NEW EMISSIONS UNITS

This permit authorizes modification of the following existing emissions unit.

ID	Emission Unit Description
014	Mill Boiler No. 16 is a 211 mmBTU per hour package boiler fired with natural gas or distillate oil.

REGULATORY CLASSIFICATION

Title III: The facility may have emissions of individual hazardous air pollutants (HAPs) at levels greater than 10 tons per year and emissions of total HAPs greater than 25 tons per year.

Title IV: The facility is not subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

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

PERMITTING AUTHORITY

All documents related to applications for permits to construct or modify an emissions unit 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 an emissions unit 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.

COMPLIANCE AUTHORITIES

All documents related to compliance activities such as reports, tests, and notifications 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. 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.

APPENDICES

The following Appendices are attached in Section IV as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format

Appendix Db. NSPS Subpart Db Requirements for Boilers

Appendix GC. General Conditions

Appendix SC. Standard Conditions

Appendix XS. Continuous Monitor Systems Quarterly Report

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.

- Permit application received on 03/23/01 and all related correspondence to make complete.
- Initial draft permit package issued on June 4, 2001.
- Revised draft permit package issued on (DRAFT).
- Comments received from the public, the applicant, the Palm Beach County Health Department, the South District Office, the EPA Region 4 Office, and the National Park Service.

CITATION FORMAT

Appendix CF 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 GC 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. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
4. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]
5. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]
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: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and copies to each 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 modified emissions unit.

Emissions Unit 014: Mill Boiler No. 16
Description: This unit is Babcock and Wilcox Model No. FM 120-97 package boiler with a maximum steam production rate of 150,000 pounds per hour (24-houraverage). The design heat release rate for this unit is greater than 70,000 BTU/hour-ft^3.
Fuels: This unit is fired with pipeline-quality natural gas or very low sulfur distillate oil.
Capacity: The heat input is 211 mmBTU per hour when firing natural gas, which is approximately 0.207 million cubic feet of gas per hour based on a heat content of 1020 mmBTU per million SCF. The heat input is 202 mmBTU per hour when firing very low sulfur distillate oil, which is approximately 1433 gallons per hour based on a heat content of 141 mmBTU per thousand gallons.
Controls: The efficient combustion of clean fuels minimizes emissions of CO, PM/PM_{10}, SO_2, and VOC. Emissions of NOx are reduced with low NOx burners and flue gas recirculation (approximately 15%).
Stack Parameters: Exhaust gases exit a 75 feet tall stack that is 5.0 feet in diameter with a volumetric flow rate of approximately 88,200 acfm at 410° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT: The emissions standards specified for this unit represent determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2). Appendix BD of this permit lists the final BACT determinations for this project. [Rules 62-212.400(BACT) and 62-296.406 (BACT for small boilers), F.A.C.]

CONTROL EQUIPMENT

2. Low NOx Burners: The permittee is authorized to install, tune, maintain and operate a modified burner system to include Coen low-NOx burners (or equivalent) with flue gas recirculation capable of achieving the emissions standards specified in this permit. The system shall be capable of firing pipeline-quality natural gas and very low sulfur distillate oil. [Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Authorized Fuel: The boiler shall fire only pipeline-quality natural gas (< 2 grains per 100 SCF) or very low sulfur distillate oil with a maximum sulfur content of 0.05% sulfur by weight. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

4. Permitted Capacity: The maximum heat input rate to the boiler shall not exceed 211 mmBTU per hour when firing natural gas nor 202 mmBTU per hour when firing very low sulfur distillate oil. The maximum steam production rate is 150,000 pounds per hour based on a 24-hour block average of the last 24 boiler operating hours. The boiler shall be equipped with integrating fuel flow meters to monitor the consumption of natural gas and distillate oil. The boiler shall be equipped with instruments to continuously monitor the steam production rate (pounds per hour), steam temperature (° F), and steam pressure (psig). [Rule 62-210.200(PTE), F.A.C.]

5. Restricted Operation: The hours of operation are not limited (8760 hours per year). The boiler shall fire no more than 10,000,000 gallons of very low sulfur distillate oil during any consecutive 12 months. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

(Permitting Note: Appendix BD lists the BACT determinations for this project.}

6. Emissions Standards: Emissions from the boiler shall not exceed the following limits for carbon monoxide (CO), nitrogen oxides (NOx), opacity, particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Pollutant	Natural Gas Firing		Distillate Oil Firing		Rule Citation (F.A.C.)
	lb/mmBTU	lb/hour[g]	lb/mmBTU	lb/hour[g]	
CO[a]	0.10	21.1	0.11	22.2	Avoid Rule 62-212.400 (BACT)
NOx[b]					Rule 62-212.400 (BACT)
Initial	0.06	12.7	0.12	24.2	
24-hour block	0.10	NA	0.20	NA	
30-day rolling	0.06	NA	0.12	NA	
Opacity[c]	10% opacity, except for one 6-minute period per hour that does not exceed 27% opacity				Rule 62-212.400 (BACT)
PM/PM10[d]	Efficient combustion of natural gas		Firing of very low sulfur distillate oil		Rule 62-212.400 (BACT), and Rule 62-296.406 (BACT)
SO_2[e]	Firing of natural gas		Firing of very low sulfur distillate oil		Rule 62-296.406 (BACT)
VOC[f]	Efficient combustion of natural gas		Efficient combustion of very low sulfur distillate oil		Avoid Rule 62-212.400 (BACT)

a. Compliance with the CO standards shall be based on the average of three test runs conducted at permitted capacity as determined by EPA Method 10.

b. Compliance with the "initial" NOx standards shall be based on data collected by the certified NOx continuous emissions monitoring system (CEMS) for each run conducted during the initial tests for CO emissions. As determined by the certified NOx CEMS, compliance with the 24-hour NOx standards shall be based on the block average of the last 24 boiler operating hours. As determined by the certified NOx CEMS, compliance with the 30-day rolling NOx standards shall be based on the rolling average of the last 30 boiler operating days.

c. The opacity standard is based on a 6-minute block average, as determined by the certified continuous opacity monitoring system (COMS). EPA Method 9 may also be used to determine compliance with the opacity standard.

d. When firing natural gas, the expected maximum PM emissions are 0.002 lb/mmBTU (0.4 lb/hour). When firing very low sulfur distillate oil, the maximum expected PM emissions are 0.03 lb/mmBTU (6.1 lb/hour). Compliance with the CO and opacity standards shall serve as indicators of good combustion. No testing is required.

e. The fuel specifications of this permit effectively limit the potential SO_2 emissions. No testing is required. When firing natural gas, the expected maximum SO_2 emissions are 0.001 lb/mmBTU (0.2 lb/hour). When firing very low sulfur distillate oil, the expected maximum SO_2 emissions are 0.06 lb/mmBTU (12.1 lb/hour).

f. When firing natural gas, the expected maximum VOC emissions are 0.03 lb/mmBTU (6.3 lb/hour). When low sulfur distillate oil, the expected maximum VOC emissions are 0.03 lb/mmBTU (6.1 lb/hour). Compliance with the CO and opacity standards shall serve as indicators of good combustion. No testing is required.

g. Maximum hourly emissions are based on the emissions standards and the maximum allowable heat input from each fuel.

CONTINUOUS MONITORING REQUIREMENTS

7. NOx CEMS: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the emissions of NOx from the boiler in a manner sufficient to demonstrate continuous compliance with the emission standards of this permit. The emission rate (pounds per mmBTU) shall be calculated by the CEMS using F-factors that are appropriate for each fuel fired. For purposes of determining compliance with the emission standards of this permit, missing or excluded data shall not be substituted. The monitoring system shall be installed, calibrated, and properly functioning prior to the initial emissions compliance tests and shall be used to demonstrate continuous compliance with the specified NOx emissions standards. [Rule 62-212.400(BACT), F.A.C.]

   a. *Monitor Certification.* The NOx CEMS shall: be certified in accordance with Performance Specification 2 in Appendix B of 40 CFR 60; comply with the monitoring requirements of 40 CFR 60.13; have dual span capability with a "low" span no greater than "0.18 pounds per mmBTU" (or equivalent) and a "high" span no greater than 0.60 pounds per mmBTU" (or equivalent); and comply with the quality assurance procedures in Appendix F of 40 CFR 60. The required RATA test shall be performed prior to the initial emissions compliance tests using EPA Method 7E of Appendix A in 40 CFR 60.

   b. *Data Collection.* The NOx CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages.

   c. *Emission Rate:* Compliance with the 24-hour NOx standards shall be based on the average of the CEMS data collected during each block of 24 boiler operating hours. Data for each 24-hour block shall be exclusive from data in other 24-hour blocks. A "boiler operating hour" means a 1-hour block of time during which the boiler combusted any fuel. It is not necessary for fuel to have been combusted continuously for the entire hour. Compliance with the 30-day NOx standards shall be based on the average of the CEMS data collected during the last 30 boiler operating days, rolled for each new boiler operating day. A "boiler operating day" means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the boiler. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

   d. *Data Exclusion.* NOx emissions data shall be recorded by the CEMS during all episodes of startup, shutdown, and malfunction. In accordance with Condition No. 11, individual NOx hourly average emission rate values may be excluded from the compliance average due to startups, shutdowns, and unavoidable malfunctions. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction.

{Permitting Note: Compliance with these requirements will ensure compliance with other applicable CEMS requirements, such as: Rule 62-297.520, F.A.C.; 40 CFR Part 51, Appendix P; 40 CFR 60.7(a)(5); 40 CFR 60.13; 40 CFR 60.48b; 40 CFR 60.49b; 40 CFR 60, Appendix B; and 40 CFR 60, Appendix F.} [40 CFR 60.48b; Rule 62-212.400(BACT), F.A.C.]

8. Opacity COMS: The permittee shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) to measure and record the opacity from the boiler in a manner sufficient to demonstrate continuous compliance with the emission standards of this permit. The COMS shall: be certified in accordance with Performance Specification 1 in Appendix B of 40 CFR 60; comply with the monitoring requirements of 40 CFR 60.13; and comply with the quality assurance procedures in Appendix F of 40 CFR 60. It shall be installed and functioning properly prior to the initial emissions compliance tests. The COMS shall be used to demonstrate continuous compliance with the corresponding opacity standards specified in this permit based on a 6-minute average. [40 CFR 60.48b; Rule 62-212.400(BACT), F.A.C.]

9. Monitor Availability: The availability of each required monitor shall not be less than 90% in any calendar quarter. The quarterly report required in Appendix XS shall be used to demonstrate monitor availability. In the event 90% availability is not achieved, the permittee shall submit a report to each Compliance Authority that identifies the problems in achieving 90% availability and a plan of corrective actions that will be taken to achieve 90% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. The Department may require additional testing for failure to maintain at least 90% monitor availability. [40 CFR 60.48b; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

10. Excess Emissions - Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such emissions shall be included in the calculation of the continuous compliance averages for opacity and NOx emissions. [Rule 62-210.700(4), F.A.C.]

11. Startup, Shutdown and Malfunction Plan: In accordance with Rule 62-210.700(5), F.A.C., the following permit conditions define alternate opacity standards and allow the exclusion of NOx monitoring data during specified periods of startup, shutdown, and unavoidable malfunction. These conditions shall only apply if operators employ the best operational practices to minimize the amount and duration of emissions during these incidents.

    a. *Visible Emissions*: Opacity shall be recorded by the COMS during all episodes of startup, shutdown and malfunction. During startup and shutdown, visible emissions shall not exceed 20% opacity except for one 6-minute period per hour that does not exceed 27% opacity, based on a 6-minute average.

    b. *CEM System Data Exclusion*: NOx emissions data shall be recorded by the CEMS during all episodes of startup, shutdown and malfunction. Individual hourly average NOx emission rate values may be excluded from the continuous NOx compliance determinations due to startups, shutdowns, or unavoidable malfunctions. No more than two (2) hourly average emission rate values shall be excluded in any 24-hour period (block or daily) due to all such episodes.

    c. *Notification*: Within three days of recording emissions in excess of a standard, the permittee shall notify the Compliance Authority by telephone or facsimile.

These conditions are established in place of the provisions specified in Rule 62-210.700(1), F.A.C.

[Design; Rules 62-4.070(3), 62-4.130, 62-210.700(5), and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

12. Initial Compliance Tests: An initial performance test for CO emissions when firing natural gas shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the modified boiler. Within 60 days of firing distillate oil in the modified boiler, an initial performance test for CO emissions shall be conducted. The continuous opacity and NOx monitors shall be installed and functioning properly (satisfactory performance specification tests and initial RATA) prior to conducting any emissions performance tests. Data collected by the certified continuous opacity and NOx monitors shall be summarized for each CO test run and submitted as part of the test report to demonstrate compliance with the initial opacity and NOx standards. Separate initial performance tests for opacity and NOx emissions are not required. Emissions of CO and NOx shall be reported in terms of "pounds per mmBTU of heat input" and "pounds per hour" using the appropriate F-factors for each fuel. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)1, F.A.C.; Applicant Request]

13. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the boiler shall be tested to demonstrate compliance with the CO emission standards for each authorized fuel that is fired for more than 400 hours. Data collected by the certified continuous opacity and NOx monitors shall be summarized for each CO test run and submitted as part of each test report. Compliance with the opacity and NOx standards are determined by data collected from the continuous monitors and separate annual performance tests for these pollutants are not required. Emissions of CO and NOx shall be reported in terms of "pounds per mmBTU of heat input" and "pounds per hour" using the appropriate F-factors for each fuel. The annual test report shall also indicate the date the annual NOx RATA was performed and summarize the results. If no fuel is fired for more than 400 hours, the permittee shall submit a summary of the opacity and NOx emissions data within 30 days of the end of the federal fiscal year. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

14. Test Methods: As required, tests shall be performed in accordance with the following reference methods.

EPA Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train.

In addition, it may be necessary to perform EPA Methods 1 through 4 as part of the above test methods. These test methods are specified in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used to demonstrate compliance unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. Other applicable testing requirements are included in Appendix SC of the permit. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

RECORDS

15. Fuel Sulfur Records: Compliance with the distillate oil sulfur limit shall be demonstrated by taking an initial sample, analyzing the sample for fuel sulfur, and reporting the results with the initial emissions

compliance test report. Sampling and analyzing the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent distillate oil delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content. [Rules 62-4.070(3), 62-4.160(15), and 62-297.310(7)(b), F.A.C.]

16. Monthly Operations Summary: By the seventh calendar day of each month, the permittee shall record the following information in a written or electronic log.

    - Hours and gallons of distillate oil firing for the previous month and the previous 12 months;
    - Hours and SCF of natural gas firing for the previous month and the previous 12 months; and
    - Maximum and average steam production (pounds per hour) for the previous month.

    Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request from the Department or a Compliance Authority. [Rules 62-4.160(15) and 62-4.070(3), F.A.C.]

REPORTS

17. Continuous Monitor System Quarterly Report: Within thirty (30) days following each calendar quarter, the permittee shall submit a report to each Compliance Authority summarizing emissions in excess of a permit standard, periods of data exclusion, and monitor availability for the previous calendar quarter. The report shall also identify and describe any malfunctions causing emissions in excess of a permit standard. The report shall be submitted for each required monitoring system and shall generally follow the NSPS format provided in Appendix XS of this permit. If necessary, the report shall include a corrective action plan to achieve at least 90% monitor availability. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

OTHER REQUIREMENTS

18. Applicable Requirements: The boiler is also subject to the "NSPS Subpart Db Requirements for Boilers" in Appendix Db and the "Standard Conditions" in Appendix SC. These appendices are found in Section IV of this permit.

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FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

The following table summarizes the final Best Available Control Technology determinations for this project as well as the emissions standards. [Rules 62-212.400 (BACT) and 62-296.406 (small boiler BACT), F.A.C.]

Pollutant	Natural Gas Firing		Distillate Oil Firing		Control Technology
	lb/mmBTU	lb/hour	lb/mmBTU	lb/hour	
CO [a]	0.10	21.1	0.11	22.2	The efficient combustion of clean fuels avoids a BACT determination for CO emissions.
NOx [b]	0.06, 30-day 0.10, 24-hr	12.7	0.12, 30-day 0.20, 24-hr	24.2	BACT is low NOx burners with flue gas recirculation and the firing of clean fuels.
Opacity [c]	10% opacity based on a 6-minute average, except for one 6-minute period per hour ≤ 27% opacity				BACT is the efficient combustion of clean fuels.
PM [d]	Efficient combustion of natural gas		Efficient combustion of very low sulfur distillate oil		BACT is the efficient combustion of clean fuels.
SO2 [e]	Firing of natural gas		Firing distillate oil with less than 0.05% sulfur by weight		BACT is the firing of very low sulfur fuels.
VOC [f]	Efficient combustion of natural gas		Efficient combustion of very low sulfur distillate oil		The efficient combustion of clean fuels avoids a BACT determination for VOC emissions.

a. Compliance is based on a 3-hour test average as determined by EPA Method 10.

b. Compliance is based on 30-day and 24-hour rolling averages as determined by certified NOx CEMS.

c. Compliance is based on a 6-minute average as determined by certified COMS and/or EPA Method 9.

d. Efficient combustion is demonstrated by compliance with the CO and opacity standards.

e. Compliance is based on a fuel sulfur analysis and fuel vendor receipts.

f. Efficient combustion is demonstrated by compliance with the CO and opacity standards.

FINAL BACT DETERMINATIONS

As summarized in this table, the Department determines that the standards specified in the permit represent the Best Available Control Technology (BACT) for emissions of nitrogen oxides (NOx), particulate matter (PM), and sulfur dioxide (SO2) from the modified boiler. The Department's rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit and the Final Determination issued concurrently with the final permit.

Determination By:

(DRAFT)

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

Recommended By:

(DRAFT)

C. H. Fancy, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

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 CRF 60.7]

Means: Title 40, Part 60, Section 7

NSPS SUBPART DB REQUIREMENTS FOR BOILERS

The NSPS requirements of this section apply to the following emissions unit:

ID	Emission Unit Description
014	Mill Boiler No. 16 is a 211 mmBTU per hour package boiler fired with natural gas or distillate oil.

NSPS GENERAL PROVISIONS

The emissions unit is subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

NSPS SUBPART DB – STANDARDS OF PERFORMANCE FOR INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

The boiler shall comply with all applicable requirements of 40 CFR 60, Subpart Db adopted by reference in Rule 62-204.800(7)(b), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes related to the Subpart Db requirements are shown in **bold** immediately following the section to which they refer.

60.40b Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu/hour.

60.41b Definitions

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference -see Section 60.17).

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 0.5 lb/million BTU heat input.

60.42b Standard for Sulfur Dioxide

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel receipts as described in Section 60.49b(r).

{Note: The permit limits fuels to pipeline natural gas and distillate oil (≤ 0.05% sulfur by weight).}

60.43b Standard for Particulate Matter

(b) On and after the date on which the performance test is completed or required to be completed under Section 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 0.10 lb/million Btu heat input.

{Note: Not applicable; the project does not include equipment to reduce sulfur dioxide emissions.}

(f) On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

{Note: The permit limits visible emissions below this level.}

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

60.44b Standard for Nitrogen Oxides

(a) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under Section 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

(1) Natural gas and distillate oil:

(ii) High heat release rate: 0.20 lb/million BTU of heat input (expressed as NO_2)

{Note: The permit limits NOx emissions below this level.}

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis.

{Note: NOx emission limits in the permit are based on both 24-hour and 30-day rolling compliance averages.}

60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in Section 60.49b(r).

{Note: The permit contains record keeping requirements for monitoring the fuel sulfur.}

60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(a) The particulate matter emission standards and opacity limits under Section 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under Section 60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under Section 60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(c) Compliance with the nitrogen oxides emission standards under Section 60.44b shall be determined through performance testing under paragraph (e) of this section.

(d) To determine compliance with the particulate matter emission limits and opacity limits under Section 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under Section 60.8 using the following procedures and reference methods:

(1) Method 3B is used for gas analysis when applying Method 5.

(2) Method 5 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems;

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller

sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160° C (320° F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5 by traversing the duct at the same sampling location.

(6) For each run using Method 5, the emission rate expressed in lb/million Btu heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Method 9 is used for determining the opacity of stack emissions.

{Note: The permit requires initial compliance with the opacity limits to be demonstrated with data collected from the continuous opacity monitoring system and initial compliance with the particulate matter standard for distillate oil firing by EPA Method 5.}

(e) To determine compliance with the emission limits for nitrogen oxides required under Section 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under Section 60.8 using the continuous system for monitoring nitrogen oxides under Section 60.48(b).

(1) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standards under Section 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

{Note: The permit requires continuous NOx monitoring to demonstrate compliance.}

60.47b Emission Monitoring for Sulfur Dioxide

(f) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in Section 60.49b(r).

{Note: The permit contains satisfactory record keeping requirements for monitoring the fuel sulfur.}

60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides

(a) The owner or operator of an affected facility subject to the opacity standard under Section 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

{Note: The permit requires continuous opacity monitoring to demonstrate compliance.}

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under Section 60.44b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides emissions discharged to the atmosphere and record the output of the system.

{Note: The permit requires continuous NOx monitoring to demonstrate compliance.}

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under Section 60.13(h) shall be expressed in lb/million Btu heat input and shall be used to calculate the average emission rates under Section 60.44b. The 1-hour averages shall be calculated using the data points required under Section 60.13(b). At least 2 data points must be used to calculate each 1-hour average.

(e) The procedures under Section 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows: 500 ppm nitrogen oxides for natural gas and oil firing.

{Note: The permit requires a lower maximum span consistent with the lower NOx emission limits.}

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

{Note: NOx emission limits in the permit are based on both 24-hour and 30-day rolling compliance averages with a 90% monitor availability.}

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 million Btu/hour) or less, and which has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section, or

60.49b Reporting and Recordkeeping Requirements

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by Section 60.7. This notification shall include:

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

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

{Note: The permit application satisfies this notification requirement.}

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under Secs. 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in Appendix B.

{Note: The permit requires initial performance testing and continuous monitoring for opacity and NOx.}

(f) For facilities subject to the opacity standard under Section 60.43b, the owner or operator shall maintain records of opacity.

(g) The owner or operator of an affected facility subject to the nitrogen oxides standards under Section 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (expressed as lb NO_2/million Btu heat input) measured or predicted.

(3) The 30-day average nitrogen oxides emission rates (lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under Section 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

{Note: The permit also specifies NOx emission limits based on a 24-hour compliance average.}

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under Section 60.43b(e) or to the operating parameter monitoring requirements under Section 60.13(i)(1).

(2) Any affected facility that is subject to the nitrogen oxides standard of Section 60.44b, and that

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less, or

(ii) Has a heat input capacity of 73 MW (250 million Btu/hour) or less and is required to monitor nitrogen oxides emissions on a continuous basis under Section 60.48b(g)(1) or steam generating unit operating conditions under Section 60.48b(g)(2).

(3) For the purpose of Section 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under Section 60.43b(f).

(4) For purposes of Section 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average nitrogen oxides emission rate, as determined under Section 60.46b(e), which exceeds the applicable emission limits in Section 60.44b.

{Note: The permit requires submittal of a quarterly report whether or not there are any excess emissions.}

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for nitrogen oxides under Section 60.48(b) shall submit a quarterly report containing the information recorded under paragraph (g) of this section. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

{Note: The permit requires submittal of a quarterly report whether or not there are any excess emissions.}

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under Section 60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in Section 60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

{Note: The permit contains satisfactory record keeping requirements for monitoring the fuel sulfur.}

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 CONDITIONS

{Permitting Note: The following conditions are generally applicable to all emissions units.}

EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

TESTING REQUIREMENTS

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

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

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

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

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

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

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

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.]

CONTINUOUS MONITOR SYSTEMS QUARTERLY REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Opacity

Reporting period dates: From ______________________ to ______________________

Company: ______________________

Emission Limitation: ______________________

Address: ______________________

Monitor Manufacturer and Model No.: ______________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ______________________

Total source operating time in reporting period [a]: ______________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

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

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

Note: On a separate page, describe any changes to the monitoring systems, processes or controls during last quarter.

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

____
Name

____
Title

______________________ ______________
Signature *Date*

Memorandum

Florida Department of
Environmental Protection

TO:	~~Clair Fancy, Chief,~~ BAR by aaj 9/25
THROUGH:	Al Linero, Administrator - New Source Review Section aaj 9/24
FROM:	Jeff Koerner, New Source Review Section JK
DATE:	September 20, 2001
SUBJECT:	Project No. 0990005-009-AC, Revised Draft Permit Draft Air Permit No. PSD-FL-169A Okeelanta Corporation, Sugar Mill and Refinery Conversion of Boiler No. 16 to Natural Gas

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- *Revised* Draft Permit; and
- PE Certification

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, the rule applicability, and the BACT determinations. The P.E. certification briefly summarizes the proposed project and BACT determinations. The following is a brief summary of the permit processing history:

- A draft permit was issued on June 4th, which stopped the permitting time clock. The original public notice has not been published.
- The applicant filed an extension with OGC to preserve their rights to file for an administrative hearing.
- At the applicant's request, we met (07/02/01) and discussed proposed changes with their consultant and attorney. The draft permit specified NOx limits based on a 24-hour average. The applicant requested NOx limits based on a 30-day rolling average, similar to the NSPS Subpart Db requirements. We agreed to establish the NOx limits based on a 30-day rolling average for the first year of operation, which would then tighten to a 24-hour average after operational experience was gained.
- Subsequently, the plant's environmental manager opposed the change because it did not provide the flexibility needed for some planned low load operation. As a result, the applicant filed another extension with OGC to preserve their rights to file for an administrative hearing.

I have worked with the applicant's consultant and come to the following agreement: higher 24-hour NOx limits will be established (based on past CEMS data) in addition to the requested 30-day NOx limits. Other minor changes and corrections were also made. I spoke with attorney Jay Lavia (Landers & Parsons, P.A.) on September 19th and he stated that the applicant would not file another extension. The current extension expired on September 19, 2001. The permitting time clock remains tolled. I recommend your approval of the attached *Revised* Draft Permit for this project.

CHF/AAL/jfk

Attachments

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

P.E. CERTIFICATION STATEMENT

PERMITTEE

Okeelanta Corporation
21250 U.S. Highway 27
South Bay, FL 33493

Project No. 0990005-009-AC
Revised Draft Permit No. PSD-FL-169A
Facility ID No. 0990005
SIC Nos. 2061, 2062, and 4911

PROJECT DESCRIPTION

The applicant, Okeelanta Corporation, operates an existing sugar mill and sugar refinery located approximately six miles south of South Bay on U.S. 27 in Palm Beach County, Florida. Adjacent to the sugar mill and refinery is Okeelanta Power L.P.'s existing cogeneration plant, which fires biomass to produce steam for the mill and generate electricity for sale to the power grid. The applicant proposes to modify the burner system of existing mill Boiler No. 16 to accommodate natural gas as the primary fuel and very low sulfur distillate oil as an alternate fuel. This unit is a package steam boiler with a capacity of 150,000 pounds per hour of steam with a heat input of approximately 200 mmBTU per hour. The existing boiler was subject to PSD during initial construction and has a NOx CEMS and opacity COMS in accordance with the NSPS Subpart Db requirements for boilers.

The existing facility is a PSD-major source of air pollution located in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). As such, BACT determinations are required for NOx and PM_{10} because emissions from the boiler exceed the PSD Significant Emission Rates for these pollutants. In addition, BACT determinations are required for emissions of PM and SO_2 in accordance with Rule 62-296.406, F.A.C. (small boiler BACT). I recommend the following emissions standards as BACT for this project:

Pollutant	BACT Standards	BACT Controls
CO	CO (gas) ≤ 0.10 lb/mmBTU based on a 3-hour test average CO (oil) ≤ 0.11 lb/mmBTU based on a 3-hour test average	Efficient combustion of clean fuels avoids BACT
NOx	NOx (gas) ≤ 0.10 lb/mmBTU based on a 24-hour block CEMS average NOx (gas) ≤ 0.06 lb/mmBTU based on a 30-day rolling CEMS average NOx (oil) ≤ 0.20 lb/mmBTU based on a 24-hour block CEMS average NOx (oil) ≤ 0.12 lb/mmBTU based on a 30-day rolling CEMS average	Low NOx burners with flue gas recirculation (≈ 15%)
PM	Opacity (gas and oil) ≤ 10% based on a 6-minute COMS average, except for one 6-minute period per hour not to exceed 27% opacity	Efficient combustion of clean fuels
SO_2	Efficient combustion of natural gas and distillate oil (< 0.05% sulfur by wt.)	Very low sulfur fuels

The Department's meteorologist reviewed the applicant's Air Quality Analysis and determined that the project would not result in any significant impacts. Therefore, the Department has reasonable assurance that the proposed project, as described in the application and subject to the conditions of the Draft Permit, will not cause or significantly contribute to a violation of any AAQS or PSD increment.

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

Jeffery J. Koer

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

9-19-01
(Date)