STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC50-219795
PSD-FL-197
Palm Beach County

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

/

Enclosed is construction Permit Number AC50-219795 (PSD-FL-197) for a 60 megawatt (MW) electric cogeneration facility to be constructed at the Osceola Farms' sugar mill located near Pahokee, Palm Beach County, Florida. This permit is issued purusant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permits pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on Sept. 28, 1993 to the listed persons.

Clerk Stamp

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

(Clerk) 9-27-93 (Date)

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

Final Determination

Osceola Power Limited Partnership
Pahokee, Palm Beach County, Florida

60 Megawatt (MW) Electric Cogeneration Facility

Permit No.: AC 50-219795
PSD-FL-197

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

September 17, 1993

FINAL DETERMINATION

The Technical Evaluation and Preliminary Determination for a permit to construct (AC50-219795/PSD-FL-197) a 60 megawatt (MW) electric cogeneration facility for Osceola Power Limited Partnership, P. O. Box 86, South Bay, Florida 33493, was distributed on June 4, 1993. The cogeneration facility will be built at Osceola Farms' sugar mill located at the intersection of U.S. Highway 98 and Hatton Highway near Pahokee, Palm Beach County, Florida. The Notice of Intent to Issue was published in the Palm Beach Post on June 9, 1993. Copies of the evaluation were available for public inspection at the Department offices in Tallahassee, Ft. Myers, and West Palm Beach and at the Palm Beach County Health Department office in West Palm Beach.

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

In letters dated July 2 and August 1, 1993, the applicant commented that some treated or painted wood could escape detection and be burned in the boilers without exceeding any air pollution standards. He presented a plan to minimize the amount of this material that would be burned. He also asked that the prohibition on the burning of "special waste" be deleted from the permit, that they not be required to analyze the ash, noted that the fossil fuel heat input was less than 25 percent on a quarterly basis instead of 25 percent on an annual basis, asked permission to use both existing and new boilers during initial cogeneration plant operations, asked that they not be required to cover the coal pile, asked that a 3-hour sulfur dioxide standard for coal and a visible emissions standard be added to the permit, asked for a delay in testing the emissions from some of the permitted fuels, asked to be allowed to use other test methods than the ones listed in the permit, and that they be allowed more than 2 hours for excess emissions during startup conditions. Except for the cover on the coal pile and the analysis of the ash, the Department finds their comments acceptable and have made the following changes, along with minor editioral changes, to the proposed permit:

Specific Conditions Nos. 1 and 11 and the project description were amended to clarify that the 60 MW capacity of this facility is a gross, 1-hour average, except during emission compliance and equipment performance tests.

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

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

Specific Condition No. 19 was revised to include a visible emission standard and a 3-hour sulfur dioxide standard for coal based on the new source performance standard for electrical utility steam generating units.

Specific Condition No. 19 also was amended to allow additional time for excess emissions during startup.

Specific Condition No. 23 was revised to require emission tests for arsenic, chromium, and copper.

The final action of the Department will be to issue construction Permit No. **AC**50-219795 (PSD-FL-197) as proposed in the Technical Evaluation and Preliminary Determination except for the changes noted above.

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

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

Permit Number: AC50-219795
PSD-FL-197
Expiration Date: July 1, 1996
County: Palm Beach
Latitude/Longitude: 26°49'45"N
80°33'00"W
Project: Cogeneration Facility

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

Construct a 60 (gross) megawatt (MW), electric, (1-hour average), cogeneration facility (biomass--bagasse and wood waste material as the primary fuel, No. 2 oil as a supplementary fuel, and low sulfur coal as an alternate fuel) at Osceola Farms' sugar mill that is east of Pahokee, Palm Beach County, Florida. The cogeneration facility contains two ABB Model VU-40 (or equivalent) spreader-stoker steam boilers with a design heat input for each boiler of 665 million British thermal units per hour (MMBtu/hr) on biomass and 460 MMBtu/hr on fossil fuels. Each boiler will produce approximately 427,400 lbs/hr of steam at 1,500 pounds per square inch gauge (psig) and 950°F. Particulate matter, nitrogen oxides, and mercury emissions from each boiler will be controlled by Flakt, Inc. (or equivalent) electrostatic precipitator, Thermal DeNO$_x$ (or equivalent) selective non-catalytic reduction system, and an activated carbon injection (or equivalent) system, respectively. Auxiliary equipment includes feed and ash handling systems, steam turbines and condensers, electric generators, cooling towers, and stacks that are 7.0 ft. in diameter and, a minimum 180 ft. high.

The UTM coordinates of this facility are Zone 17, 544.2 km E and 2968.0 km N.

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

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

GENERAL CONDITIONS:

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

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

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

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

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

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

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

GENERAL CONDITIONS:

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

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

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

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

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

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

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

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

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

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

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

GENERAL CONDITIONS:

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

13. This permit also constitutes:

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

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

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

SPECIFIC CONDITIONS:

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application. The facility shall be designed, constructed, and operated so that its gross generating capacity shall not exceed 60 megawatt (MW), 1 hour average, except during scheduled emission compliance and equipment performance tests. Equipment performance testing in excess of 60 MW shall be limited to a total of 24 hours (cumulative) during the 180-day calendar period after initial firing of each boiler. The permittee shall provide the Department with engineering, monitoring, and reporting plans for the generation capacity of the facility within 30 days after the plans become available.

2. Boilers Nos. 1 and 2 shall be of the spreader stoker type with a maximum heat input of 665 million British thermal units per hour (MMBtu/hr) with biomass fuel and 460 MMBtu/hr with fossil fuels.

3. Each boiler shall have an individual stack, and each stack must have a minimum height of 180 feet. The stack sampling facilities for each stack must comply with F.A.C. Rule 17-297.345.

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

5. Each boiler shall be equipped with a:

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

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_x), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO). The monitoring devices shall meet the applicable requirements of Section 17-297.500, F.A.C., and 40 CFR 60.47a. The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the stack or in the stack.

An oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/fuel ratio parameters at an optimum. Operating procedures shall be established based on the initial emission compliance tests required by Specific Condition No. 20 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. An operating plan shall be submitted to the Department within 90 days of completion of such tests.

SPECIFIC CONDITIONS:

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

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

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

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

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

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

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

Operational and Emission Restrictions

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application. The facility shall not exceed 60 (gross) megawatts generating capacity, 1 hour average, except during emission compliance and equipment

SPECIFIC CONDITIONS:

performance tests. Equipment performance tests shall be limited to a 180 day calendar period after initial firing of each boiler. The maximum heat input rate for each steam generator shall not exceed 665 MMBtu/hr when burning 100 percent biomass and 460 MMBtu/hr when burning 100 percent No. 2 fuel oil or low sulfur coal. Maximum heat input to the entire facility (total of two boilers) shall not exceed 7.0×10^{12} Btu per year. Steam production of each boiler shall not exceed an average of 427,409 lbs/hr at 1,500 psig, 950°F.

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

The fuel used at the cogeneration facility shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The bio-mass fuel used at the cogeneration facility shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The permittee shall not use any delivered fuel that contains an amount of treated or painted wood which, if burned, would cause an exceedance of any of the Deparment's Acceptable Ambient Concentration (AAC). The wood waste shall not contain more than 56.7 parts per million (ppm) arsenic or 67.2 ppm chromium or 53.2 ppm copper based on analysis of a composite sample of the fuel.

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

The permittee shall design and implement a management and testing program for the wood waste and other materials delivered to the facility for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. This program shall be submitted to the Department's Bureau of Air Regulation for review and approval at least 60 days before the commencement of operations of the cogeneration facility. At a minimum, the program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Fuel scheduled for burning shall be inspected daily. Fuel tests shall be conducted weekly for the first year of operations at the facility and monthly thereafter, if the Department determines on the basis of the prior test results that less frequent testing is appropriate.

SPECIFIC CONDITIONS:

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

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

15. The consumption of No. 2 fuel oil shall be less than 25 percent of the total heat input to each boiler unit in any calendar quarter. The plant shall not burn more than 20,065 tons of coal during any 12-month period (12-month rolling average). The combined use of coal and oil shall be less than 25 percent of the total heat input to this cogeneration facility on a calendar quarter basis.

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

17. During the first three years of commercial cogeneration facility operation, the existing Boilers Nos. 2, 3, 4, 5, and 6 (Permit Nos. AO50-203679, 165813, 203680, 165626, and 165814, respectively) may be retained for standby operation provided their operating permits are valid.

During the period from initial firing to commercial operation, both cogeneration boilers can be operated simultaneously with the existing boilers. Only biomass and No. 2 fuel oil may be used in the cogeneration boilers during this period. If more than 495,000 lb/hr steam, (24-hour average) is generated in the cogeneration boilers, steam in excess of 495,000 lb/hr (24-hour average) must be sent to the Osceola sugar mill, and the existing boiler's steam production reduced by an equivalent amount. This period shall not exceed a total duration of 12 months. During this 12-month period, simultaneous operation of the existing boilers and the cogeneration boilers shall not occur on more than a total of 90 calendar days. After the first year of cogeneration facility operation, the existing boilers may be operated only when both new cogeneration boilers are shutdown. During operation, the existing boilers must meet all requirements in the most recent construction and operation permits for the boilers. The existing boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

SPECIFIC CONDITIONS:

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

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

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

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

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

19. Visible emissions from any cogeneration boiler shall not exceed 20 percent opacity, 6 minutes average, except up to 27 percent opacity is allowed for 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 665 MMBtu/hr for biomass fuels and 460 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	Emission Limit (per boiler)[d]						Total[e]
	Biomass		No. 2 Oil		Bit. Coal		Both
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	20.0	0.03	13.8	0.03	13.8	105.0
Particulate (PM_{10})	0.03	20.0	0.03	13.8	0.03	13.8	105.0
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	552.0	---
24-hour average	0.10	66.5	0.05	23.0	1.2	552.0	---
Annual average	0.02[a]	---	---	---	1.2[a]	---	353.2[f]
Nitrogen Oxides							
Annual average	0.12[a]	79.8[a]	0.12[a]	55.2[a]	0.17[a]	78.2[a]	424.9

SPECIFIC CONDITIONS:

Carbon Monoxide 8-hour average	0.35	232.8	0.2	92.0	0.2	92.0	1,225.0
Volatile Organic Compounds	0.06	39.9	0.03	13.8	0.03	13.8	210.0
Lead	2.5×10^{-5}	0.017	8.9×10^{-7}	0.0004	6.4×10^{-5}	0.029	0.10
Mercury	6.3×10^{-6}[b] 0.29×10^{-6}[c]	0.0042[b] 0.00019[c]	2.4×10^{-6}	0.0011	8.4×10^{-6}	0.0039	0.0161
Beryllium	---	---	3.5×10^{-7}	0.00016	5.9×10^{-6}	0.0027	0.0014
Fluorides	---	---	6.3×10^{-6}	0.003	0.024	11.0	5.8
Sulfuric Acid Mist	0.003	2.00	0.0015	0.69	0.036	16.6	5.2

[a]Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.
[b]Emission limit for bagasse. Subject to revision pursuant to Specific Conditions Nos. 23 and 24.
[c]Emission limit for wood waste. Subject to revision pursuant to Specific Conditions Nos. 23 and 24.
[d]The emission limit shall be prorated when more than one type of fuel is burned in a boiler.
[e]Limit heat input of No. 2 fuel oil to less than 25% of total heat input on a calendar quarter basis and coal to 20,065 tons during any 12-month period. Combined heat input of coal and oil shall be less than 25% of the total heat input on a calendar quarter basis.
[f]Compliance based on a 12-month rolling average.

The permittee shall comply with the excess emissions rule contained in F.A.C. Rule 17-296.210. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

Compliance Requirements

20. Stack Testing

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 19 (including visible emissions). Tests shall be conducted during normal operations (i.e., within 10 percent of the permitted heat input) and the permittee shall furnish the Department a written report of the results of such emissions compliance tests within 45 days of completion of the tests. The emissions compliance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

SPECIFIC CONDITIONS:

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 19 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

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

SPECIFIC CONDITIONS:

104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.
EMTIC Test Method	Chromium and copper emissions.

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

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

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

23. Stack tests for particulates, NO_x, SO_2, sulfuric acid mist, CO, VOC, lead, mercury, beryllium, fluorides, arsenic, chromium, copper, and visible emissions shall be performed once every six months during the first two years of facility operation in accordance with Specific Conditions Nos. 20, 21, and 22 above. If the test results for the first two years of operation indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the tests will thereafter occur according to the following schedule:

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

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

24. After conducting the initial stack tests required under Specific Condition No. 23 above, a fuel management plan shall be submitted to the Department and Palm Beach County within 90 days specifying the fuel types and fuel quantities to be burned in the facility in order to not exceed the facility annual mercury, lead, beryllium, and fluorides emission limits specified in Condition 19

SPECIFIC CONDITIONS:

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

Reporting Requirements

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

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

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

Issued this 27 day
of September, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Department of Environmental
Protection

Best Available Control Technology (BACT) Determination
Osceola Power Limited Partnership
Palm Beach County
AC50-219795 (PSD-FL-197)

The applicant proposes to construct a 60 MW (gross) electric cogeneration facility consisting of two 665 MMBtu/hr spreader-stoker boilers that will burn biomass (bagasse and wood waste material), No. 2 fuel oil, and coal. The proposed cogeneration facility will be constructed at Osceola Farms Company's sugar mill that is located near Pahokee, Palm Beach County, Florida. During the period from initial firing to commercial operation of the cogeneration facility, both new and existing boilers can be operated simultaneously for up to 90 days while the new system is being debugged. Five existing bagasse/No. 6 fuel oil fired boilers at the sugar mill will be shut down when the cogeneration facility begins commercial operation.

The cogeneration facility will cause a significant net emissions increase of sulfur dioxide, fluorides, and beryllium. Therefore, the project is subject to new source review pursuant to the Prevention of Significant Deterioration (PSD) regulations (F.A.C. Rule 17-212.400). This BACT determination is part of the PSD requirements.

Date of Receipt of a BACT Application: September 30, 1992

The BACT Determination requested by the applicant is summarized below:

Sulfur Dioxide: The recommended BACT is the use of low sulfur fuel: biomass, typically 0.009 percent sulfur; No. 2 fuel oil with a maximum of 0.05 percent sulfur, and coal with a maximum of 0.7 percent sulfur. Also, limiting the total No. 2 fuel oil burned in the boilers to be less than 25 percent of the heat input on a calendar quarter basis, limiting the amount of coal burned at the facility to 20,065 tons during any 12-month period, limiting the combination of coal and oil burned in the boilers to less than 25 percent of the heat input on a calendar quarter basis, and limiting the sulfur dioxide emissions to 353.2 TPY are conditions of the BACT determination.

Fluorides: The recommended BACT is limiting the quantity of low sulfur coal burned in the facility, the primary source of fluorides, to a maximum of 7 percent of the total annual heat input and the use of an ESP to capture particulates containing the pollutant.

Beryllium: Same as above.

A summary of the emission limits proposed by the applicant for each pollutant subject to the BACT determination follows:

Proposed Emission Limits for the Osceola Power Facility

Pollutants	Emission Limits (lbs per MMBtu/lbs per hr per boiler) Fuels*		
	Biomass	No. 2 fuel oil	Coal
SO_2	0.10/66.5	0.05/23.0	1.2/552.0
Beryllium	--	3.5E-7/1.6E-4	5.9E-6/2.7E-3
Fluorides	--	6.3E-6/3.0E-3	2.4E-2/11.0

* Maximum heat input per boiler

Biomass - 665 MMBtu/hr
No. 2 fuel oil - 460 MMBtu/hr
Coal - 460 MMBtu/hr

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212.410, Best Available Control Technology Determination, Stationary Source-Preconstruction Review, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to 40 CFR 52.21, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent

control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

BACT Determination by DER

Pollutant	Emission Limit (lbs/MMBtu)	Control Technology	EPA Test Method
Sulfur Dioxide	0.10 (biomass) 0.02 (30-day rolling avg. on biomass) 0.05 (No. 2 fuel oil) 1.2 (coal)(30-day rolling avg.)	Low sulfur fuel (0.05 percent max. for No. 2 fuel oil; 0.70 percent max. for coal); max. heat input of less than 25 percent on a calendar quarter basis from No. 2 fuel oil; a max. 20,065 TPY coal burned; a max. heat input of less than 25 percent on a calendar quarter basis for the combination of coal and oil; and limiting sulfur dioxide emissions to 353.2 TPY (12-month rolling average)	6, 6C, or 19 and continuous emissions monitoring.
Beryllium	3.5E-7 (No. 2 fuel oil) 5.9E-6 (coal)	Max. heat input of less than 25 percent on a calendar quarter basis from No. 2 fuel oil, 7 percent of the heat input for coal, less than 25 percent of the heat input on a calendar quarter basis for the combination of coal and oil, and use of an ESP	104

Fluorides	6.3E-6 (No. 2 fuel oil) 2.4E-2 (coal)	Max. heat input of less than 25 percent on a calendar quarter basis from No. 2 fuel oil, 7 percent coal, less than 25 percent on a calendar quarter basis combination coal and oil, and use of an ESP	13A or 13B

BACT Determination Rationale

Sulfur Dioxide: The proposed facility is subject to PSD because of the proposed potential emissions of the alternate coal fuel. The coal will contain a maximum of 0.70 percent sulfur. The applicant proposes that the heat input from the combination of coal and fuel oils be limited to less than 25 percent on a calendar quarter basis of the total heat input for the boilers. Thus, over 75 percent of the heat input (minimum) for the boilers will be provided by biomass -- a fuel that averages 0.009 percent sulfur. The highest SO_2 emissions, 1.2 lbs/MMBtu heat input and 353.2 TPY, will occur when 7 percent of the heat input is provided by coal containing 0.70 percent sulfur. These emissions meet the applicable new source performance standards, 40 CFR 60, Subpart Da. The use of either a wet limestone scrubber or lime/sodium spray dry scrubber, controls used in other BACT determinations listed in the BACT/LAER Clearinghouse document, would reduce SO_2 emissions significantly (over 90 percent). The scrubbers would also create a contaminated liquid or dry solid waste which would have to be disposed of properly. The applicant evaluated the economic, energy and environmental impacts of wet scrubbers, dry scrubbers and dry injection system, in combination with low, medium and high sulfur coal, as technically feasible control alternatives. The economic analysis estimated the total cost effectiveness over baseline of these alternatives to range from $10,487 to $20,767 per ton of SO_2 removed.

The use of a limited (20,065 TPY) amount of low sulfur (0.70 percent) coal, instead of requiring a flue gas desulfurization system, is consistent with recent BACT determination. This is especially true in cases such as Osceola Power where coal will be fired on an infrequent and intermittent basis. With the restriction on the amount of low sulfur fossil fuels that can be burned at this facility, the weighted average annual sulfur dioxide emission rate will be 0.10 lbs/MMBtu.

The total sulfur dioxide emission from both Osceola and Okeelanta Power, a similar facility proposed for the area whose application is currently being reviewed by the Department, is 1,507 TPY. The weighted average SO_2 emission rate for both these facilities is 0.168 lbs/MMBtu. This emission rate is very close to what has been

determined recently to be BACT for SO_2 for 100 percent coal-fired power plants (i.e., 0.17 lbs/MMBtu for Bechtel Indiantown and 0.25 lbs/MMBtu for OUC Stanton Unit 2).

The ambient air impact for SO_2 at the proposed emission rate has been calculated to be 0.5, 106, and 242 ug/m^3 for the annual, 24-hour, and 3-hour time periods, respectively. The allowable emissions will have less impact.

Beryllium: Traces of beryllium are present in fossil fuels. Beryllium can be vaporized and emitted as an air pollutant when these fuels are burned. At the operating temperature of the ESP, approximately 350°F, most of the beryllium should be condensed and captured by the 98 percent efficient ESP. Maximum beryllium emissions are estimated to be 5.4E-3 lbs/hr. The ambient air impact of this emission will be 8E-4, 5E-4, and 3E-5 ug/m^3 for the 8-hour, 24-hour and annual time periods, respectively. These impacts are below the Acceptable Ambient Concentration (AAC), a concentration believed to have an acceptable health risk to the public.

Fluorides: The fluorides in the fuels can be converted to acid gases during combustion. A majority of these pollutants at Osceola Power will come from the coal burned at that facility. By limiting the use of coal to 20,065 TPY, acid gases (fluorides) will be limited. Any acid gas existing in a liquid or solid phase can be captured by the ESP.

At a maximum emission rate per boiler of 11.0 lbs/hr fluorides, the 8-hour and 24-hour impacts are 3.2 and 2.1 ug/m^3. These impacts are below the AAC.

The Department concluded that the limitations on the amount of fossil fuel burned at this facility is BACT for these pollutants.

Conclusion

For the emission standards established as BACT, the ambient air impacts of the sulfur dioxide, beryllium, and fluorides will be below the ambient air standards and/or AAC for these pollutants.

Details of the Analysis May be Obtained by Contacting:
Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

September 17 1993
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

September 27 1993
Date

Reasonably Available Control Technology (RACT) Determination
Osceola Power Limited Partnership
Palm Beach County
AC50-219795 (PSD-FL-197)

The applicant proposed to construct a 60 MW (gross, 1-hour average) electric cogeneration facility consisting of two 665 MMBtu/hr spreader-stoker boilers that will burn biomass (bagasse and wood waste material), No. 2 fuel oil, and coal. The proposed cogeneration facility will be constructed at and its operations integrated into Osceola Farm Company's sugar mill. This mill is located near Pahokee, Palm Beach County, Florida. Five existing bagasse/No. 6 fuel oil boilers at the sugar mill will be replaced by the cogeneration facility when it begins commercial operation. The cogeneration facility is a major source for volatile organic compounds (210 TPY) and nitrogen oxides (424.9 TPY). However, the net contemporaneous emission change for these pollutants resulting from the cogeneration facility project, an increase of 1.4 TPY for VOC and a reduction of 12.9 TPY for NO_X, is less than the significant emission rates, Table 212.400-2, F.A.C. Thus, the project is subject to F.A.C. Rule 17-296.570, Reasonably Available Control Technology (RACT) Requirements for Major VOC - and NO_X - Emitting Facilities.

Date of Receipt of an Application Subject to RACT: Sept. 30, 1992.

The RACT Determination requested by the applicant is summarized below:

Volatile Organic Compounds: The recommended VOC air pollution control is efficient boiler design and good combustion practices based on the document titled "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls." The estimated VOC emission rates are 0.06 lbs/MMBtu on biomass and 0.03 lbs/MMBtu on No. 2 fuel oil and coal.

Nitrogen Oxides: The recommended NO_X air pollution control is use of a selective non-catalytic reduction system designed to achieve at least 40 percent NO_X reduction efficiency. The estimated NO_X emission rates are 0.12 lbs/MMBtu for biomass fuels and No. 2 fuel oil and 0.17 lbs/MMBtu for coal firing.

RACT Determination Procedure

In accordance with F.A.C. Rule 17-296.570, Reasonably Available Control Technology (RACT) Requirements for Major VOC - and NO_X - Emitting Facilities, this RACT determination is based on the applicant's proposal, published documents, and technological feasibility.

RACT Determined by DEP

Fuel	VOC lbs/MMBtu	VOC Control	NO_x lbs/MMBtu	NO_x Control
Biomass	0.06	Boiler Design, Good operation practice using the oxygen meter	0.12	Non-Catalytic reduction system
No. 2 Fuel Oil	0.03		0.12	
Coal	0.03		0.17	

RACT Determination Rationale

VOC: The applicant is committed to meeting the VOC emission limit through good design and operating practice based on a procedure that has been considered as a BACT determination for similar boilers. As a BACT determination is generally considered to establish more stringent emission standards than a RACT determination, the Department finds the applicant's proposal acceptable.

NO_x: The applicant will use a selective non-catalytic reduction system to lower NO_x emissions. The proposed NO_x emissions are lower than the limits given in the new source performance standards (NSPS) for electric utility steam generation units (40 CFR 60, Subpart Da). As a NSPS is generally considered to have a more stringent emission limit than a RACT standard, the Department finds the applicant's proposal acceptable.

There is a net reduction in the NO_x emissions from the Osceola Power Limited Partnership project. Therefore, the ambient air impacts of these pollutants from Osceola Farms Company's sugar mill will decrease.

Conclusion

Good boiler design, operation practice and use of a non-catalytic reduction system meets the VOC and NO_x RACT for the proposed cogeneration facility. The emissions will not interfere with reasonable further progress in this ozone non-attainment area.

Details of the Analysis May be Obtained by Contacting:
Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

September 17 1993
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

September 27 1993
Date

Florida Department of
Memorandum — Environmental Protection

TO: Virginia Wetherell

FROM: Howard L. Rhodes

DATE: September 27, 1993

SUBJ: Approval of Construction Permits
Okeelanta/Osceola Power Limited Partnership

Attached for your approval and signature are two PSD permits for electric/steam cogeneration facilities to be built at two sugar mills in Palm Beach County burning biomass, oil and coal. One of these permits is for 74.9 megawatts of electricity production and the other is for 60 megawatts of electricity production. Controls include reduction for nitrogen oxide, particulate, and mercury.

I recommend your approval and signature on the Permits, Best Available Control Technology determinations and Reasonably Available Control Technology determinations.

HLR/WH/bjb

Attachments

FLORIDA DEPARTMENT OF HEALTH

Jeb Bush
Governor

Robert G. Brooks, M.D.
Secretary

October 15, 1999

RECEIVED
OCT 18 1999
BUREAU OF AIR REGULATION

Mr. Clair Fancy, P.E.
Bureau Chief
Bureau of Air regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Mail Station 5505
Tallahassee, Florida 32399-2400

50 219795

Re: Osceola Power Limited Partnership, FDEP File Nos. 0990331-007-AC & PSD-FL-197
Okeelanta Power limited Partnership, FDEP File Nos. 0990332-010-AC & PSD-FL-196
September 28, 1999 Requests for Extensions to Sugar Mill Boiler Shut Down Dates

50219413
Pats #

Dear Mr. Fancy,

As you are aware, the above facilities were reviewed under the PSD regulations based on net emission increases below the significant levels for carbon monoxide (CO), oxides of nitrogen (NOx), particulate matter (PM) and volatile organic compounds (VOC). The actual emissions data for each facility are presented in Tables 1 and 2 for the past two years (1997 & 1998). As can be seen within the tables, emissions of CO, PM and VOC are significantly higher than the levels presented within the initial PSD applications. In addition, CO and VOC emissions for the period have been higher than the baselines.

Table 1, Osceola Facility

Pollutant	Baseline (TPY)	PSD Permit (TPY)	1997 (TPY)	1998 (TPY)
CO	5992.3	1225	6028	7467
NOx	437.8	436.5	494	345
PM	357.7	109.3	276	315
SO2	178.5	1071.5	248	275
VOC	208.6	210	459	244

Table 2, Okeelanta Facility

Pollutant	Baseline (TPY)	PSD Permit (TPY)	1997 (TPY)	1998 (TPY)
CO	10388	2012.5	10236	7415
NOx	888.7	862.5	757.13	620.41
PM	473.7	177.3	402.7	307.39
SO2	748.3	1700	219.8	206.1
VOC	401.9	345	802.13	656.84

The September 28, 1999 requests to amend Specific Condition No. 17 (SC #17) would allow this trend to continue for another 3 years if approved. Under the initial SC #17, operation of the cogen boilers was to be phased in over a 3-year period with the sugar mill boilers retained as standby units during this period. At the end of the 3-year period, the sugar mill boilers were to be shut down (Drop Date of 1/1/99). The focus of SC #17 was to allow operational flexibility and security to the sugar mills while ensuring that the netting analyses were federally enforceable. With the continued problems associated with the cogen facilities, it is not recommended that the Department amend the condition as requested.

It is recommended that the Department amend SC #17 to allow use of the cogen boilers and existing boilers with an additional requirement to meet daily and annual facility wide emission caps. For your information, the facilities have requested a "Bubble" within the initial Title V permit applications. The daily and annual emission caps should be based on the information presented within the PSD permit applications for the cogen facilities. Emissions in excess of these levels should be addressed through the enforcement program with formal compliance plans required within each Title V operating permit. It is believed that this approach is consistent with the PSD and Title V programs.

Because the 3-year period following initial firing has passed, it is requested that as a minimum SC #17 be amended to require the maximum use of the cogen boilers to offset steam requirements at the sugar mills.

If you have any other questions, please contact me at (561) 355-3136.

Sincerely,

For the Division Director
Environmental Health and Engineering

Darrel Graziani, PE
Air Pollution Control Section