Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 27, 1995

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

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

Re: Osceola Power Limited Partnership - 74 MW Electrical Power Cogeneration Facility - AC 50-269980/PSD-FL-197A

Dear Mr. Cepero:

Enclosed is one copy of the draft permit, technical evaluations and public notice package for the modified Osceola Power 74 MW Electrical Power Cogeneration project at the Osceola Farms Sugar Mill near Pahokee, Palm Beach County, Florida. Included is the Notice of Intent to Issue Permit for the modified project for you to publish as indicated in the instructions.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, P.E. of the Bureau of Air Regulation. Please call Willard Hanks at (904) 488-1344 if you have any questions on this matter.

Sincerely,

A A Linero 7/27 for

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

CHF/WH/m

Enclosures

cc: David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
David Buff, KBN
John Bunyak, NPS

Is your RETURN ADDRESS completed on the reverse side?

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

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

Consult postmaster for fee.

3. Article Addressed to: Luis Cepero, VP Osceola Power Ltd Partnership P O Box 86 South Bay, Fl 33493

4a. Article Number Z 392 979 062

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

7. Date of Delivery 7-31-95

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6. Signature (Agent) [signature]

PS Form 3811, December 1991 RECEIPT

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PS Form 3800, March 1993

Sent to Luis Cepero	
Street and No. Osceola PLP	
P.O., State and ZIP Code S. Bay, Fl	
Postage	$
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Postmark or Date 7-27-95 AC 50-269980 PSD-FL-197A	

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DEP File No. AC 50-269980
PSD-FL-197A
Palm Beach County

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

_____/

INTENT TO ISSUE PERMIT FOR MODIFIED PROJECT

The Department of Environmental Protection (Department) hereby gives notice of its intent to issue a permit (copy attached) for the proposed project, as detailed in the application specified above, for the reasons stated below and detailed in the attached Technical Evaluation and Preliminary Determination.

The applicant, Osceola Power Limited Partnership (OPLP), P.O. Box 86, South Bay, Florida 33493, applied on September 30, 1992, to the Department of Environmental Protection for a permit to construct a 60 electrical MW (maximum) biomass (bagasse and wood waste material), No. 2 fuel oil, and coal fired cogeneration facility. An Intent to Issue was filed on June 4, 1993, with publication of that Intent on June 9, 1993. Since then, the project has substantially modified thereby requiring additional public notice pursuant to 62-103.150(2)(a)4, F.A.C.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 62-212 and 62-4. The project is not exempt fro permitting procedures. The Department has determined that a construction permit is required for the proposed work.

The Department intends to issue a permit for the modified project, which is for a facility capable of generating 74 MW (maximum) of electrical power (instead of 60 MW) while burning the same kinds of fuels as previously projected. The reasons for approval are that this action will allow the facility to install the larger boilers available from the manufacturer, without causing or contributing to a violation of any air quality standard, PSD increment, or any other technical provision of Chapters 62-210 through 62-297 of the Florida Administrative Code.

Pursuant to Section 403.815, Florida Statutes and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Permit for modified project. The notice shall be published one time only within 30 days in the legal ad section of the newspaper of general circulation in the area affected. For the purpose of this rule, "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. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within seven days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will issue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information;

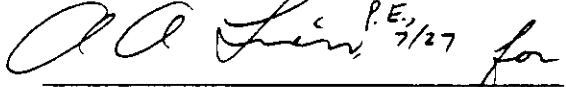
(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

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, Florida 32399-2400
904-488-1344

Osceola Power LP
AC 50-269980/PSD-FL-197A

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 7-27-95 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.

Lori Tober 7-27-95
Clerk Date

Copies furnished to:

cc: David Knowles, SD
Isidore Goldman, SED
James Stormer, PBCHD
Jewell Harper, EPA
David Buff, KBN
John Bunyak, NPS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT FOR MODIFIED PROJECT

AC 50-269980/PSD-FL-197A

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit (modification of permit No. AC 50-219795) to Osceola Power Limited Partnership, P. O. Box 86, South Bay, Florida 33493, to build a 74 MW cogeneration plant that uses biomass (bagasse and wood waste material) as the primary fuel with No. 2 fuel oil and low sulfur coal (0.70 percent) as alternate fuels instead of the 60 MW unit previously described in the Notice of Intent to Issue Permit published on June 9, 1993. The proposed facility will be constructed at the Osceola Farms' sugar mill located at the intersection of U.S. Highway 98 and Hatton Highway near Pahokee, Palm Beach County, Florida. The final configuration will consist of two (2) new 760 MMBtu/hr boilers for the proposed cogeneration facility, each using an electrostatic precipitator, a selective non-catalytic reduction system, and a carbon injection system to control air pollution. The two new boilers will replace 5 existing bagasse/No. 6 fuel oil fired boilers at the sugar mill. Each new boiler will emit up to 22.8 lbs/hr particulate matter, 636.0 lbs/hr sulfur dioxide, 5.30 lbs/hr sulfuric acid mist, 88.2 lbs/hr nitrogen oxides, 266.0 lbs/hr carbon monoxide, 12.7 lbs/hr fluorides, 0.0031 lbs/hr beryllium, 45.6 lbs/hr volatile organic compounds, and trace amounts of other criteria/non-criteria pollutants. The modified project (2 new cogeneration boilers replacing 5 existing bagasse/No. 6 oil fired-boilers) will decrease net emissions of particulate matter (-213.5 TPY), PM_{10} (-182.9 TPY), and carbon monoxide (-4,555.9 TPY); but increase net emissions of nitrogen oxides (+39.3 TPY), volatile organic compounds (+10.6 TPY), sulfur dioxide (+160.5 TPY), beryllium (+0.00128 TPY), fluorides (+5.24 TPY), and sulfuric acid mist (+0.64 TPY).

The increase in emissions are greater than the significant emission rates for sulfur dioxide, beryllium, and fluorides. Therefore, the project is subject to review under the Prevention of Significant Deterioration (PSD) regulations and the emission limits for these pollutants are established by a Best Available Control Technology (BACT) determination. The maximum predicted PSD Class II sulfur dioxide increments consumed after this modified project is constructed are as follows: 10.7 ug/m^3, annual average, or 54% of the available annual increment; 76 ug/m^3, 24-hour average, or 84% of the available 24-hour increment; and 191 ug/m^3, 3-hour average, or 37% of the available 3-hour increment. The sulfur dioxide emissions from this modification will have no significant impact in the Class I Everglades National Park.

The Department intends to issue a permit for the modified project because it will allow the facility to install the larger boilers available from the manufacturer, without causing of contributing to a violation of any air quality standard, PSD increment or any other provision of Chapter 62-210 through 62-297 of the Florida Administrative Code.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and, (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any

right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

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

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Department of Environmental Protection
Southeast District
1900 S. Congress Avenue, Suite A
West Palm Beach, Florida 33406

Department of Environmental Protection
South District
2295 Victoria Avenue, Suite 364
Ft. Myers, Florida 33901

Palm Beach County Health Department
Division of Environmental Science
and Engineering
901 E. Evernia Street
West Palm Beach, Florida 33406

Any person may send written comments on the proposed action to Administrator, New Source Review, at the Department of Environmental Protection, Bureau of Air Regulation, Mail Station 5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such request must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination
for
Modified Project

Osceola Power Limited Partnership
Pahokee, Palm Beach County, Florida

74 MW (previously 60 MW) Electrical Power Cogeneration Facility

Department File No. AC 50-269980
PSD-FL-197A

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

July 27, 1995

I. GENERAL INFORMATION

A. Applicant

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

* This facility is controlled by Osceola Farms Company. The initial application for a cogeneration facility at this site was submitted under the name of Sol-Energy, Inc.

B. Request

On September 30, 1992, Osceola Power Limited Partnership (Osceola Power), submitted an application for permit to construct a 60 MW (maximum) of electrical power cogeneration facility that will use biomass (bagasse and wood waste material) as the primary fuel with No. 2 fuel oil and low sulfur coal (0.70 percent) as alternate fuels. On April 12, 1994, the permit was modified to allow 65 MW of generation. On April 26, 1995, the permittee submitted an application to construct a 74 MW instead of the permitted 65 MW electrical power cogeneration facility. This application is being treated as a request for a permit to construct a modified project which is different than the one previously described in the Notice of Intent to Issue Permit published June 9, 1993.

C. Emissions

The emissions from the facility are a direct function of the type of fuel being burned. Biomass is the primary fuel. No. 2 fuel oil is a supplementary fuel. Low sulfur coal (0.70 percent) is an alternate fuel that may be burned when biomass is unavailable. The applicant requested that fossil fuel consumption (No. 2 fuel oil and coal) be limited by permit restriction to a total of 25 percent of the annual heat input to the cogeneration boilers. The burning of coal at this facility is further limited to 5.4 percent of the total annual heat input. In addition, total sulfur dioxide emissions due to all fuels will be limited to 339 TPY.

The following tables from the application summarize the proposed heat input and emissions for the two cogeneration boilers:

Table 2-2: Maximum Fuel Usage and Heat Input Rates
Table 2-4: Proposed Emission Limits

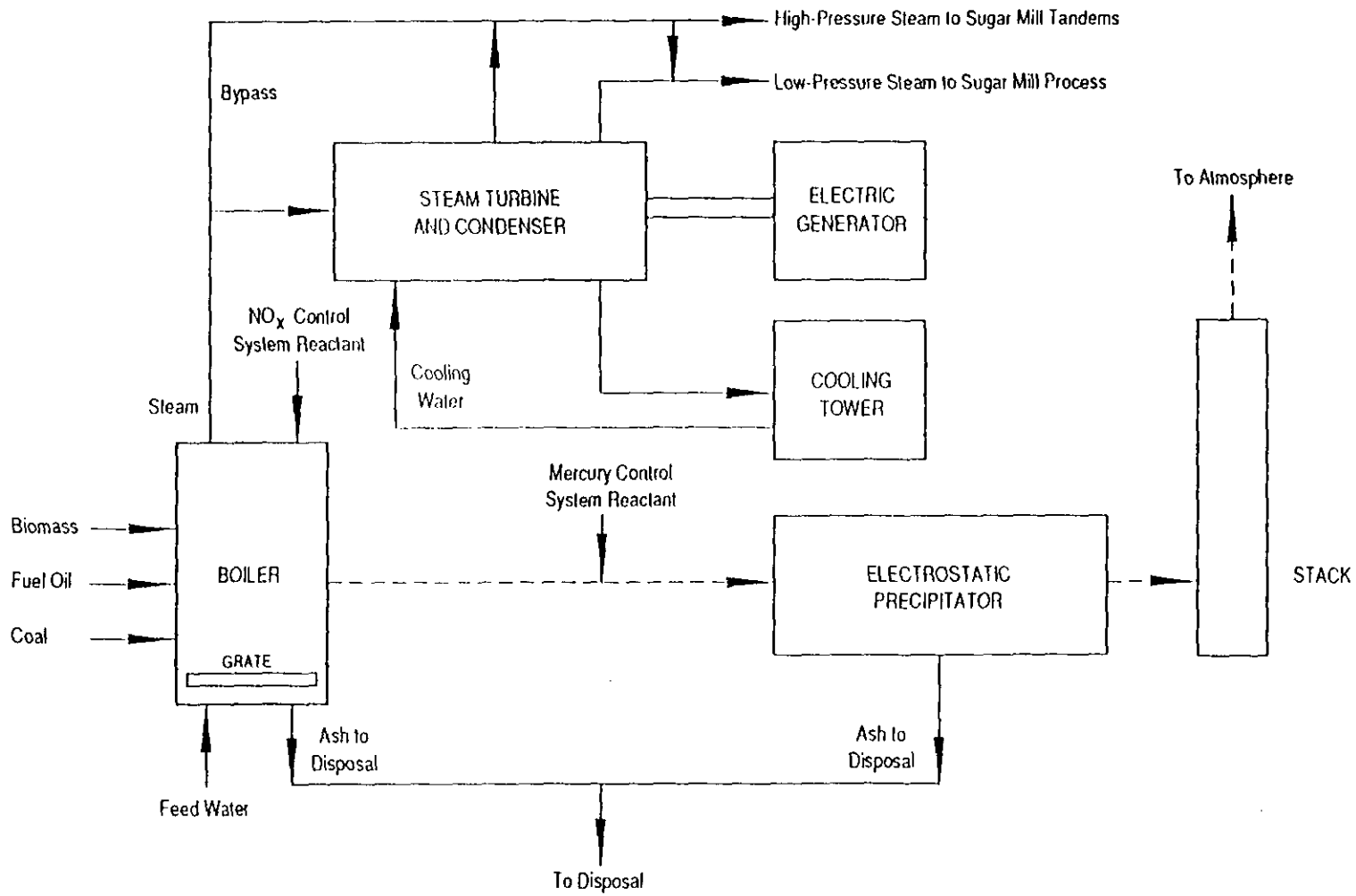


Figure 2-4 SIMPLIFIED FLOW DIAGRAM FOR SOL-ENERGY COGENERATION FACILITY

Table 2-2. Maximum Fuel Usage and Heat Input Rates, Osceola Power Limited Partnership

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate
	Maximum Short-Term (per boiler) (MMBtu/hr)		(MMBtu/hr)	
Biomass	760	68	517	178,824 lb/hr
No. 2 Fuel Oil	600	85	510	4,348 gal/hr
Coal	530	85	451	44,167 lb/hr
	Annual Average (total two boilers) (Btu/yr)		(Btu/yr)	
NORMAL OPERATIONS				
Biomass	8.208E+12	68	5.581E+12	965,647 TPY
No. 2 Fuel Oil	0	85	0	0 gal/yr
Coal	0	85	0	0 TPY
TOTAL	8.208E+12		5.581E+12	
25% OIL FIRING				
Biomass	5.793E+12	68	3.939E+12	681,529 TPY
No. 2 Fuel Oil	1.931E+12	85	1.641E+12	13,992,754 gal/yr
Coal	0	85	0	0 TPY
TOTAL	7.724E+12		5.581E+12	
5.4% COAL FIRING				
Biomass	7.661E+12	68	5.209E+12	901,294 TPY
No. 2 Fuel Oil	0	85	0	0 gal/yr
Coal	4.373E+11	85	3.717E+11	18,221 TPY
TOTAL	8.098E+12		5.581E+12	

Notes: Total heat output required = 5.581E+12 Btu/yr total both boilers.
Fuels may be burned in combination, not to exceed total heat outputs.
Based on fuel heating values as follows:
Bagasse – 4,250 Btu/lb
No. 2 Fuel Oil – 138,000 Btu/gal
Coal – 12,000 Btu/lb

Basis for annual heat input

Grinding season: 440,000 lb/hr/boiler steam; 658 MMBtu/hr/boiler; 140 crop days
Heat input= 4.4218E+12 Btu/yr

Non-grinding season: 273,150 lb/hr/boiler steam; 369 MMBtu/hr/boiler; 225 crop days; 95% capacity
Heat input= 3.7859E+12 Btu/yr

Totals: Heat input= 8.2077E+12 Btu/yr

Table 2-4. Proposed Emission Limits for the Osceola Power Facility (DEP Revision)

Pollutant	Emission Limit (lb/MMBtu) Biomass	No. 2 Oil	Bit. Coal
Particulate (TSP)	0.03	0.03	0.03
Particulate (PM10)	0.03	0.03	0.03
Sulfur Dioxide			
24-hour average	0.10	0.05	1.2
Annual average[a]	0.02	0.05	1.2
Nitrogen Oxides			
Annual Average[a]	0.12	0.12	0.15
Carbon Monoxide			
8-hr average	0.35	0.2	0.2
Volatile Organic Compounds (Bagasse)	0.06	0.03	0.03
(Wood)	0.04		
Lead	2.7E-06	8.9E-07	5.1E-06
Mercury (Bagasse)	5.7E-06	2.4E-06	8.4E-06
(Wood)	2.9E-07		
Beryllium	--	3.5E-07	5.9E-06
Fluorides	--	6.3E-06	0.024
Sulfuric Acid Mist	0.0049	0.0025	0.010

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

Table 2-5. Maximum Hourly Emissions for Osceola Power Cogeneration Facility (per boiler).

Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Maximum Emissions for any fuel (lb/hr)
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	
Particulate (TSP)	0.03	760	22.8	0.03	600	18.0	0.03	530	15.9	22.8
Particulate (PM10)	0.03	760	22.8	0.03	600	18.0	0.03	530	15.9	22.8
Sulfur dioxide[a]	0.10	760	76.0	0.05	600	30.0	1.2	530	636.0	636.0
Nitrogen oxides[b]	0.116	760	88.2	0.12	600	72.0	0.15	530	79.5	88.2
Carbon monoxide[c]	0.35	760	266.0	0.20	600	120.0	0.20	530	106.0	266.0
VOC- Bagasse	0.060	760	45.6	0.03	600	18.0	0.03	530	15.9	45.6
Wood Waste	0.040	760	30.4							
Lead	2.7E-06	760	0.0021	8.9E-07	600	0.0005	5.1E-06	530	0.0027	0.0027
Mercury- Bagasse	5.7E-06	760	0.0043	2.4E-06	600	0.0014	8.4E-06	530	0.0045	0.0045
Wood Waste	2.9E-07	760	0.00022							
Beryllium	--	--	--	3.5E-07	600	0.0002	5.9E-06	530	0.0031	0.0031
Fluorides	--	--	--	6.27E-06	600	0.0038	0.024	530	12.7	12.72
Sulfuric acid mist	0.0049	760	3.72	0.0025	600	1.5	0.010	530	5.30	5.30
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl chloride	--	--	--	--	--	--	--	--	--	--

[a] 24-hour average.
[b] 30-day rolling average.
[c] 8-hour average.

Table 2-6. Maximum Annual Emissions for Osceola Power L. P. Cogeneration Facility (total all boilers)

Regulated Pollutant	Biomass			No. 2 Fuel			Coal			Total Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Normal Operations										
Particulate (TSP)	0.03	8.208	123.12	--	--	--	--	--	--	123.12 a
Particulate (PM10)	0.03	8.208	123.12	--	--	--	--	--	--	123.12 a
Sulfur dioxide	0.02	8.208	82.08	--	--	--	--	--	--	82.08
Nitrogen oxides	0.116	8.208	476.06	--	--	--	--	--	--	476.06
Carbon monoxide	0.35	8.208	1,436.40	--	--	--	--	--	--	1,436.40 a
VOC- Bagasse	0.060	5.499 b	164.98	--	--	--	--	--	--	219.15 a
Wood waste	0.040	2.709 c	54.17							
Lead	2.7E-06	8.208	0.011	--	--	--	--	--	--	0.011
Mercury- Bagasse	5.7E-06	5.499 b	0.01567	--	--	--	--	--	--	0.0161
Wood waste	2.9E-07	2.709 c	0.00039							
Beryllium	--	--	--	--	--	--	--	--	--	--
Fluorides	--	--	--	--	--	--	--	--	--	--
Sulfuric acid mist	0.00098	8.208	4.02	--	--	--	--	--	--	4.02
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--
25% Oil Firing										
Particulate (TSP)	0.03	5.793	86.90	0.03	1.931	28.97	--	--	--	115.86
Particulate (PM10)	0.03	5.793	86.90	0.03	1.931	28.97	--	--	--	115.86
Sulfur dioxide	0.02	5.793	57.93	0.05	1.931	48.28	--	--	--	106.21
Nitrogen oxides	0.116	5.793	335.99	0.12	1.931	115.86	--	--	--	451.85
Carbon monoxide	0.35	5.793	1,013.78	0.20	1.931	193.10	--	--	--	1,206.88
VOC- Bagasse	0.060	3.881 b	116.44	0.03	1.931	28.97	--	--	--	183.64
Wood waste	0.040	1.912 c	38.23							
Lead	2.7E-06	5.793	0.008	8.9E-07	1.931	0.001	--	--	--	0.009
Mercury- Bagasse	5.7E-06	3.823 b	0.01090	2.4E-06	1.931	0.0023	--	--	--	0.0135
Wood waste	2.9E-07	1.912 c	0.00028							
Beryllium	--	--	--	3.5E-07	1.931	0.0003	--	--	--	0.00034
Fluorides	--	--	--	6.27E-06	1.931	0.0061	--	--	--	0.006
Sulfuric acid mist	0.00098	5.793	2.84	0.0025	1.931	2.37	--	--	--	5.20
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--
5.4% Coal Firing										
Particulate (TSP)	0.03	7.661	114.92	--	--	--	0.03	0.4373	6.56	121.47
Particulate (PM10)	0.03	7.661	114.92	--	--	--	0.03	0.4373	6.56	121.47
Sulfur dioxide	0.02	7.661	76.61	--	--	--	1.2	0.4373	262.38	338.99 a
Nitrogen oxides	0.116	7.661	444.34	--	--	--	0.15	0.4373	32.80	477.14 a
Carbon monoxide	0.35	7.661	1,340.68	--	--	--	0.20	0.4373	43.73	1,384.41
VOC- Bagasse	0.060	5.133 b	153.99	--	--	--	0.03	0.4373	6.56	160.55
Wood waste	0.040	2.528 c	50.56							
Lead	2.7E-06	7.661	0.010	--	--	--	5.1E-06	0.4373	0.0011	0.011 a
Mercury- Bagasse	5.7E-06	5.133 b	0.01463	--	--	--	8.4E-06	0.4373	0.00184	0.0168 a
Wood waste	2.9E-07	2.528 c	0.00037							
Beryllium	--	--	--	--	--	--	5.9E-06	0.4373	0.0013	0.0013 a
Fluorides	--	--	--	--	--	--	0.024	0.4373	5.25	5.25 a
Sulfuric acid mist	0.00098	7.661	3.75	--	--	--	0.010	0.4373	2.25	6.00 a
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--

[a] Denotes maximum annual emissions for any fuel scenario.
[b] Represents 67% of total heat input.
[c] Represents 33% of total heat input.

Table 2-11. Maximum Hourly Emissions of Florida Air Toxics for Osceola Power Cogeneration Facility (per boiler).

Florida Air Toxic	Biomass			No. 2 Fuel Oil			Coal			Maximum Emission For Any Fuel (lb/hr)
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	
Acetone	3.8E-04	760	0.29	--	--	--	--	--	--	0.29
Ammonia	1.50E-02	760	11.4	1.50E-02	600	9.00	0.048	530	25.44	25.4
Barium	5.20E-06	760	0.0040	6.69E-07	600	0.00040	7.44E-05	530	0.039	0.039
Benzo(a)anthracene	7.53E-07	760	0.00057	--	--	--	--	--	--	0.00057
Benzo(a)pyrene	3.53E-08	760	2.68E-05	--	--	--	--	--	--	2.68E-05
Bromine	4.59E-05	760	0.035	6.97E-07	600	0.00042	7.90E-05	530	0.042	0.04
Chrysene	3.53E-05	760	0.027	--	--	--	--	--	--	0.027
Copper - Maximum	1.25E-04	760	0.095	4.20E-05	600	0.025	1.71E-04	530	0.091	0.095
Indium	1.27E-04	760	0.10	--	--	--	--	--	--	0.10
Iodine	2.12E-06	760	0.0016	--	--	--	--	--	--	0.0016
Isopropanol	9.20E-03	760	6.99	--	--	--	--	--	--	6.99
Molybdenum	2.24E-07	760	0.00017	4.88E-07	600	0.00029	8.83E-06	530	0.0047	0.0047
PAH	5.90E-10	760	4.48E-07	--	--	--	--	--	--	--
Silver	1.40E-06	760	0.0011	--	--	--	--	--	--	0.0011
Thallium	ND	--	--	--	--	--	--	--	--	--
Tin	3.65E-08	760	2.77E-05	3.3E-06	600	0.0020	8.83E-06	530	0.0047	0.0047
Tungsten	1.29E-08	760	9.80E-06	--	--	--	--	--	--	9.80E-06
Vanadium	1.41E-07	760	0.00011	--	--	--	--	--	--	0.00011
Yttrium	6.59E-08	760	5.01E-05	--	--	--	--	--	--	5.008E-05
Zirconium	4.12E-07	760	0.00031	--	--	--	--	--	--	0.00031

Note: ND = Non-detectable

Source: KBN, 1995.

Table 2-12. Maximum Annual Emissions of Florida Air Toxics for Osceola Power Cogeneration Facility (total all boilers)

Florida Air Toxic	Biomass			No. 2 Fuel Oil			Coal			Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Normal Operations										
Acetone	3.8E-04	8.208	1.56	--	--	--	--	--	--	1.56 *
Ammonia	1.50E-02	8.208	61.56	--	--	--	--	--	--	61.56
Barium	5.20E-06	8.208	0.021	--	--	--	--	--	--	0.021
Benzo(a)anthracene	7.53E-07	8.208	0.0031	--	--	--	--	--	--	0.0031 *
Benzo(a)pyrene	3.53E-08	8.208	0.00014	--	--	--	--	--	--	0.00014 *
Bromine	4.59E-05	8.208	0.19	--	--	--	--	--	--	0.19
Chrysene	3.53E-05	8.208	0.14	--	--	--	--	--	--	0.14 *
Copper - Annual	8.02E-05	8.208	0.33	--	--	--	--	--	--	0.33 *
Indium	1.27E-04	8.208	0.52	--	--	--	--	--	--	0.52 *
Iodine	2.12E-06	8.208	0.0087	--	--	--	--	--	--	0.0087 *
Isopropanol	9.20E-03	8.208	37.76	--	--	--	--	--	--	37.76 *
Molybdenum	2.24E-07	8.208	0.00092	--	--	--	--	--	--	0.00092
PAH	5.90E-10	8.208	2.42E-06	--	--	--	--	--	--	2.42E-06 *
Silver	1.40E-06	8.208	0.0057	--	--	--	--	--	--	0.0057 *
Thallium	ND	--	--	--	--	--	--	--	--	--
Tin	3.65E-08	8.208	0.00015	--	--	--	--	--	--	0.00015
Tungsten	1.29E-08	8.208	5.29E-05	--	--	--	--	--	--	5.29E-05 *
Vanadium	1.41E-07	8.208	0.00058	--	--	--	--	--	--	0.00058 *
Yttrium	6.59E-08	8.208	0.00027	--	--	--	--	--	--	0.00027 *
Zirconium	4.12E-07	8.208	0.0017	--	--	--	--	--	--	0.0017 *
25% Oil Firing										
Acetone	3.8E-04	5.793	1.10	--	--	--	--	--	--	1.10
Ammonia	1.50E-02	5.793	43.45	1.50E-02	1.647	12.35	--	--	--	55.80
Barium	5.20E-06	5.793	0.015	6.69E-07	1.647	0.00055	--	--	--	0.016
Benzo(a)anthracene	7.53E-07	5.793	0.0022	--	--	--	--	--	--	0.0022
Benzo(a)pyrene	3.53E-08	5.793	0.00010	--	--	--	--	--	--	0.00010
Bromine	4.59E-05	5.793	0.13	6.97E-07	1.647	0.00057	--	--	--	0.13
Chrysene	3.53E-05	5.793	0.10	--	--	--	--	--	--	0.10
Copper - Annual	8.02E-05	5.793	0.23	--	--	--	--	--	--	0.23
Indium	1.27E-04	5.793	0.37	--	--	--	--	--	--	0.37
Iodine	2.12E-06	5.793	0.0061	--	--	--	--	--	--	0.0061
Isopropanol	9.20E-03	5.793	26.65	--	--	--	--	--	--	26.648
Molybdenum	2.24E-07	5.793	0.00065	4.88E-07	1.647	0.00040	--	--	--	0.0011
PAH	5.90E-10	5.793	1.71E-06	--	--	--	--	--	--	1.71E-06
Silver	1.40E-06	5.793	0.0041	--	--	--	--	--	--	0.0041
Thallium	ND			--	--	--	--	--	--	--

Table 2-12. Maximum Annual Emissions of Florida Air Toxics for Osceola Power Cogeneration Facility (total all boilers)

Florida Air Toxic	Biomass			No. 2 Fuel Oil			Coal			Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Tin	3.65E-08	5.793	0.00011	3.3E-06	1.647	0.0027	--	--	--	0.0028 *
Tungsten	1.29E-08	5.793	3.74E-05	--	--	--	--	--	--	3.74E-05
Vanadium	1.41E-07	5.793	0.00041	--	--	--	--	--	--	0.00041
Yttrium	6.59E-08	5.793	0.00019	--	--	--	--	--	--	0.00019
Zirconium	4.12E-07	5.793	0.0012	--	--	--	--	--	--	0.0012
Yttrium	6.59E-08	5.793	0.00019	--	--	--	--	--	--	0.00019
Zirconium	4.12E-07	5.793	0.0012	--	--	--	--	--	--	0.0012
	5.4 % Coal Firing									
Acetone	3.8E-04	7.661	1.46	--	--	--	--	--	--	1.46
Ammonia	1.50E-02	7.661	57.46	--	--	--	0.048	0.482	11.57	69.03 *
Barium	5.20E-06	7.661	0.020	--	--	--	7.44E-05	0.482	0.018	0.038 *
Benzo(a)anthracene	7.53E-07	7.661	0.0029	--	--	--	--	--	--	0.0029
Benzo(a)pyrene	3.53E-08	7.661	0.00014	--	--	--	--	--	--	0.00014
Bromine	4.59E-05	7.661	0.18	--	--	--	7.90E-05	0.482	0.019	0.19 *
Chrysene	3.53E-05	7.661	0.14	--	--	--	--	--	--	0.14
Copper - Annual	8.02E-05	7.661	0.31	--	--	--	--	--	--	0.31
Indium	1.27E-04	7.661	0.49	--	--	--	--	--	--	0.49
Iodine	2.12E-06	7.661	0.0081	--	--	--	--	--	--	0.0081
Isopropanol	9.20E-03	7.661	35.24	--	--	--	--	--	--	35.241
Molybdenum	2.24E-07	7.661	0.00086	--	--	--	8.83E-06	0.482	0.0021	0.0030 *
PAH	5.90E-10	7.661	2.26E-06	--	--	--	--	--	--	2.26E-06
Silver	1.40E-06	7.661	0.0054	--	--	--	--	--	--	0.0054
Thallium	ND	--	--	--	--	--	--	--	--	--
Tin	3.65E-08	7.661	0.00014	--	--	--	8.83E-06	0.482	0.0021	0.0023
Tungsten	1.29E-08	7.661	4.94E-05	--	--	--	--	--	--	4.94E-05
Vanadium	1.41E-07	7.661	0.00054	--	--	--	--	--	--	0.00054
Yttrium	6.59E-08	7.661	0.00025	--	--	--	--	--	--	0.00025
Zirconium	4.12E-07	7.661	0.0016	--	--	--	--	--	--	0.0016
Yttrium	6.59E-08	7.661	0.00025	--	--	--	--	--	--	0.00025 *
Zirconium	4.12E-07	7.661	0.0016	--	--	--	--	--	--	0.0016

a Denotes maximum annual emissions for any fuel scenario.

Note: ND = Non-detectable

Table 2 – 13. Osceola Power Facility Maximum Annual Fugitive Dust Emissions

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (%)	U WIND SPEED (MPH)	UNCONTROLLED EMISSION FACTOR (LB/TON) a	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM(TSP) EMISSIONS (TONS/YR)	PM10 SIZE MULT.	MAXIMUM ANNUAL PM10 EMISSIONS (TONS/YR)
Coal Handling											
RAILCAR UNLOADING	BATCH DROP	4.5	9.4	0.00234	ENCLOSURE	70	0.00070	18,221 TPY	0.006	0.35	0.002
CONVEYOR – TO – COAL PILE	CONTINUOUS DROP	4.5	9.4	0.00234	NONE	0	0.00234	18,221 TPY	0.021	0.35	0.007
UNDERPILE RECLAIM HOPPER	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	90	0.00023	18,221 TPY	0.002	0.35	0.001
CONVEYOR – TO – CRUSHER	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	0	0.00234	18,221 TPY	0.021	0.35	0.007
COAL CRUSHER	COAL CRUSHING	– –	– –	0.02 h	ENCLOSURE	70	0.00600	18,221 TPY	0.055	0.45	0.025
CRUSHER – TO – CONVEYOR	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	0	0.00234	18,221 TPY	0.021	0.35	0.007
CONVEYOR – TO – BOILER SILO	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	0	0.00234	18,221 TPY	0.021	0.35	0.007
STORAGE PILE	WIND EROSION	– –	– –	– –	NONE	0	– –	– –	0.211 e	0.5	0.105 e
COAL STORAGE PILE MAINTENANCE	VEHICULAR TRAFFIC	– –	– –	0.98 b	WATERING	50	0.48 lb/VMT	4,800 VMT c	1.157 e	0.35	0.405 e
Biomass Handling											
TRUCK DUMPS (2)	BATCH DROP	37	9.4	0.00012	NONE	0	0.00012	865,647 TPY	0.059	0.35	0.021
CHAIN CONVEYORS – TO – UNLOADING CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
UNLOADING CONVEYOR – TO – SCREEN	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
SCREEN	CONTINUOUS DROP	37	9.4	0.00012	NONE	0	0.00012	865,647 TPY	0.059	0.35	0.021
SCREEN – TO – HOGGER	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
HOGGER	CRUSHING	– –	– –	0.02	ENCLOSED	95	0.00100	865,647 TPY	0.483	0.35	0.169
HOGGER – TO – STORAGE CONVEYOR	BATCH DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
SCREEN – TO – STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
SCREEN – TO – BOILER FEED CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
STORAGE CONVEYOR – TO – RADIAL STACKER	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
RADIAL STACKER – TO – BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00012	NONE	0	0.00012	865,647 TPY	0.059	0.35	0.021
UNDERPILE RECLAIMERS (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSED	90	0.00001	865,647 TPY	0.008	0.35	0.002
RECLAIMERS – TO – BOILER FEED CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
BOILER FEED CONVEYOR – TO – CHAIN DIST. CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
CHAIN DIST. CONVEYOR – TO – BOILER METER BINS (4)	BATCH DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	865,647 TPY	0.059	0.35	0.021
BAGASSE CONVEYOR – TO – CHAIN DIST CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
BAGASSE CONVEYOR – TO – RECYCLE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
CHAIN DIST. CONVEYORS – TO – RECYLE CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	98,565 TPY g	0.006	0.35	0.002
RECYCLE CONVEYOR – TO – RECYCLE STACKER	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
RECYCLE CONVEYOR – TO – STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	98,565 TPY g	0.006	0.35	0.002
RECYCLE STACKER – TO – BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00012	NONE	0	0.00012	0 TPY	0.000	0.35	0.000
BIOMASS STORAGE PILES (2)	WIND EROSION	– –	– –	– –	NONE	0	– –	– –	0.175 e	0.5	0.087 e
BIOMASS STORAGE PILE MAINTENANCE	VEHICULAR TRAFFIC	– –	– –	0.98 b	WATERING	50	0.48 lb/VMT	21,900 VMT d	5.278 e	0.35	1.847 e
BOILER HOUSE DUST COLLECTOR BAGHOUSE	– –	– –	– –	– –	BAGHOUSE	99	0.01 gr/acf	30,000 acfm	11.283	1.0	11.283
Mercury Control System											
CARBON SILO FILTER	– –	– –	– –	– –	BAGHOUSE	99	0.01 gr/acf	2,500 acfm	0.939	1.0	0.939
Fly Ash Handling											
FLY ASH SILO FILTER	– –	– –	– –	– –	BAGHOUSE	99	0.01 gr/acf	2,500 acfm	0.939	1.0	0.939
FLY ASH TRANSFER – TO – TRUCK	CONTINUOUS DROP	5.0	9.4	0.00202	WETTING	50	0.00101	31,954 TPY f	0.018	0.35	0.006
TOTAL									21.088		15.863

Notes/References

a Batch Drop and Continuous Drop Emission Factors are computed from AP – 42 (USEPA, 1988) Section 11.2.3:
E = 0.0032 x (U/5) ^ 1.3 / (M/2) ^ 1.4 lb/ton

b Pound per Vehicle Mile Travel (lb/VMT), see Appendix C for derivation

c Based on vehicle operating 8 hrs/day, 120 days/yr @ 5 mph.

d Based on vehicle operating 12 hrs/day, 365 days/yr @ 5 mph.

e Refer to Appendix C for derivation.

f Based on 865,647 TPY biomass @ 3.24% ash and 18,221 TPY coal @ 3.66% ash

g Assuming 10% of biomass is overfeed and is returned to biomass storage pile

h Emission Factor for Coal Crusher derived from AP – 42 Table 8.23 – 1, for high moisture ore; same factor used for biomass crushing.

Table 3-1. PSD Source Applicability Analysis for Osceola Power Limited Partnership Facility

Regulated Pollutant	Original PSD Baseline Emissions (TPY)	Cogeneration Facility Annual Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	Current Permit Limit (TPY)	PSD Applies?	Permit Amendment Required?
Particulate (TSP)	357.7	144.2[a]	-213.5	25	114.7	No	Yes
Particulate (PM10)	321.9	139.0[b]	-182.9	15	108.5	No	Yes
Sulfur dioxide	178.5	339.0	160.5	40	353.2	No	No
Nitrogen oxides	437.8	477.1	39.3	40	424.9	No	Yes
Carbon monoxide	5,992.3	1,436.4	-4,555.9	100	1,225.0	No	Yes
Volatile org. compds.	208.6	219.2	10.6	40	210.0	No[c]	Yes
Lead	0.16	0.011	-0.15	0.6	0.10	No	No
Mercury	0.0158[d]	0.0168	0.0010	0.1	0.0161	No	Yes
Beryllium	0.00002	0.0013	0.00128	0.0004	0.0014	No	No
Fluorides	0.0079	5.25	5.24	3	5.8	No	No
Sulfuric acid mist	5.36	6.00	0.64	7	5.2	No	Yes
Total reduced sulfur	—	—	0	10	—	No	No
Asbestos	—	—	0	0.007	—	No	No
Vinyl Chloride	—	—	0	0	—	No	No

[a] Includes 123.1 TPY from boilers and 21.1 TPY from fugitive dust emission sources.
[b] Includes 123.1 TPY from boilers and 15.9 TPY from fugitive dust emission sources.
[c] Nonattainment review does not apply since the increase in VOC emissions is less than 40 TPY.

Table 2-5: Maximum Hourly Emissions for Osceola Power Cogeneration Facility (per boiler).

Table 2-6: Maximum Annual Emissions (total of all boilers).

Table 2-11: Maximum Hourly Emissions of Florida Air Toxics (per boiler).

Table 2-12: Maximum Annual Emissions of Florida Air Toxics (total all boilers).

Table 2-13: Maximum Annual Fugitive Dust Emissions.

Table 3-1: PSD Source Applicability Analysis.

From Table 3-1, it can be seen that the net contemporaneous emissions change of particulate matter (PM and PM_{10}), lead, and carbon monoxide will decrease as a result of this project. The net contemporaneous emissions change of sulfur dioxide, beryllium, and fluorides will increase by more than the significant emission rates. The project will cause an increase in nitrogen oxides, volatile organic compounds, and sulfuric acid mist emissions. The applicant has committed to not increasing actual mercury emissions.

II. Rule Applicability

The proposed project, construction of a new 74 MW cogeneration plant in lieu of the previously noticed 60 MW facility at an existing sugar mill (SIC 2061) in Palm Beach County, is subject to the preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-210, 62-212, 62-272, 62-296, and 62-297, Florida Administrative Code (F.A.C.).

The facility will be located in an area designated attainment/maintenance for ozone (Rule 62-275.410, F.A.C.) and attainment for the other criteria pollutants (Rule 62-275.400, F.A.C.)

The facility is a major source of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) because the potential emissions of each of these air pollutants exceed 100 TPY (Rule 62-212.200, F.A.C.). The application is for a new major facility. The proposed facility is subject to the Prevention of Significant Deterioration (PSD) regulations (Rule 62-212.400, F.A.C.) because the increase in sulfur dioxide, beryllium, and fluoride emissions will exceed the significant rates (Rule Table 212.400-2, F.A.C.). Therefore, the project is subject to the Preconstruction Review

Requirements of Rule 62-212.400, F.A.C. The allowable emissions of the pollutants with significant emissions rate increases will be established by a Best Available Control Technology (BACT) determination (Rule 62-212.410, F.A.C.). The proposed facility is also subject to the federal new source performance standards (NSPS) for electric utility steam generating units (40 CFR 60, Subpart Da) and petroleum liquids storage vessels (40 CFR 60, Subpart Ka). The emission limits and monitoring requirements of these rules will be applied to these proposed units.

The proposed facility will not be subject to the new source review for nonattainment areas (Rule 62-212.500, F.A.C.), because the VOC and NO_X emissions will not increase above the significant emission rates. The facility is subject to Rule 62-296.570, F.A.C., Reasonable Available Control Technology, for VOC and NO_X because the proposed units are major emitters of these pollutants.

III. Technical Evaluation

The proposed 74 megawatt (maximum) electrical capacity cogeneration facility will contain two boilers capable of burning biomass, No. 2 fuel oil, and coal. The emissions from each boiler will be controlled by an electrostatic precipitator (ESP) for PM and acid mist control, selective non-catalytic reduction system (SNCR) for NO_X control, and a carbon injection system for mercury control. The two new boilers in the cogeneration system will replace five existing bagasse/No. 6 fuel oil-fired boilers at the Osceola Farm's Company's sugar mill.

The primary fuel to the cogeneration facility will be bagasse (2/3 of the heat input) and wood waste material (1/3 of the heat input). No. 2 fuel oil and coal are used as alternate fuels. The combined use of coal and oil fuels cannot exceed 25 percent of the total annual heat input to this cogeneration facility. The burning of coal will be further restricted to 18,221 tons during any 12-month period (5.4 percent of total annual heat input). In addition, total sulfur dioxide emissions will be limited to 339 tons during any 12-month period (12-month rolling average). Particulate matter (PM/PM_{10}) emissions from the new boilers will be controlled by an ESP that has a design efficiency in excess of 99 percent. The ESP will be capable of meeting the NSPS PM standard of 0.03 lbs/MMBtu heat input. The NSPS visible emissions standard is 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Compliance will be determined by periodic stack tests and the visible emissions will be continuously monitored. The proposed facility is not subject to the PSD regulations for particulate matter.

SO_2 emissions will be controlled by the use of low sulfur fuels. Biomass (bagasse and wood waste material), the primary

fuels, average about 0.009 percent sulfur. The No. 2 fuel oil, which may be used as a supplementary or alternate fuel, will have a sulfur content of 0.05 percent which will produce 0.05 lbs SO_2/MMBtu when burned. Coal, an alternate fuel to be used only when adequate quantities of biomass are not available, will be allowed a maximum sulfur content of 0.70 percent which will produce 1.2 lbs SO_2/MMBtu when burned. This emission will meet the applicable NSPS for SO_2. Compliance with the SO_2 emission standards will be demonstrated by fuel analysis, stack testing, and/or continuous emission monitoring. The facility is subject to PSD and BACT for sulfur dioxide emissions because the proposed increase in annual SO_2 emissions can exceed the significant emission rate.

NO_X emissions will be controlled by a SNCR system. The system will be designed to reduce NO_X emissions by at least 40 percent. The proposed NO_X emission limits of 0.12 lbs/MMBtu for biomass and No. 2 fuel oil, and 0.15 lbs/MMBtu for coal are below the NSPS for this type of facility. Compliance with the emission standards will be determined by stack tests and the NO_X emissions will be monitored continuously. The project will result in the net contemporaneous NO_X emissions increase of 39.3 TPY. Therefore, the project is not subject to PSD for NO_X. The proposed NO_X limit, less than the applicable NSPS, are acceptable to the Department as meeting or exceeding the applicable RACT for these units.

CO and VOC emissions will be controlled through boiler design and good combustion practices. The emissions, shown in Table 2-4 of the application, will depend on the fuel being burned. The project is expected to result in a net reduction of 4,555.9 TPY CO and an increase of 10.6 TPY VOC. Thus, the project is not subject to PSD for these pollutants. Compliance with the emission standards will be determined by stack test. Carbon monoxide and oxygen emissions will be monitored continuously to comply with the NSPS. Good operation practices, based on the guidance in the document titled "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls", is acceptable as the RACT determination to control VOC emissions.

The project is subject to the PSD regulations for sulfur dioxide, beryllium, and fluorides. These pollutants are caused primarily by the contaminants in the fossil fuels. Emissions will be controlled by limiting both the sulfur content in the fossil fuels (0.05 percent sulfur in the No. 2 fuel oil and 0.70 percent sulfur in the coal) and the quantity of fossil fuel that can be burned. The ESP may remove some particulate matter containing these pollutants. Compliance for all three pollutants shall be determined by stack tests.

The following table summarizes the emissions of air pollutants subject to PSD review.

Net Contemporaneous Emission Change Analysis
Osceola Power Limited Partnership

Based on the use of coal fuel being limited to 18,221 tons during any 12-month period (12-month rolling average) and the use of fossil fuel being limited to 25 percent of the annual heat input.

	TPY Emissions			
Pollutants	Biomass (BM)	BM+Oil	BM+Coal	Net Contemporaneous Change
Sulfur Dioxide	82.08	106.21	339	+160.5
Nitrogen Oxides	476.06	451.85	477.14	+ 39.3
Beryllium	--	3.4E-4	1.3E-3	+ 1.3E-3
Fluorides	--	6.0E-3	5.25	+ 5.24
Sulfuric Acid Mist	4.02	5.20	6.00	+ 0.64

The applicant is committed to not increasing the mercury emissions from this facility. An activated carbon injection system will be used on the new boilers to reduce mercury emissions. Stack tests will be used to establish the actual emissions of mercury, estimated to be 0.0168 TPY, and to confirm compliance with the mercury emission standard.

Reasonable precautions will be required to control fugitive particulate matter emissions from the fuels (biomass and coal), ash (boilers and ESP), and activated carbon injection system. Control will be accomplished through wetting and/or containment, and the use of dust filters on the activated carbon system silos.

IV. Air Quality Impact Analysis

a. Introduction

The Osceola Power cogeneration project as proposed by the applicant will emit three pollutants in PSD significant amounts. These pollutants include the criteria pollutant SO_2 and the noncriteria pollutants Be and Fl (Table 1).

The air quality impact analyses required by the PSD regulations for these pollutants includes:

* An analysis of existing air quality;
* A PSD increment analysis (SO_2);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts; and
* A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The PSD increment and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department of Environmental Protection (Department) has reasonable assurance that the proposed Osceola Power cogeneration project, as described in this report and subject to the conditions of approval proposed herein, will not cause or 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 CFR 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 modeling procedure and required analyses follows.

b. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

The predicted impacts of the proposed project for those pollutants subject to PSD review are listed in Table 2.

The maximum 24-hour average SO_2 concentration due to the proposed cogeneration units is predicted to be 66 ug/m^3. The de minimus concentration level for SO_2 is 13 ug/m^3, 24-hour average. Therefore, an ambient monitoring analysis is required for SO_2.

For non-criteria pollutants, such as Be and Fl, EPA's general position is to not require monitoring data, but to base the analysis of existing air quality on modeled impacts. Even though the maximum predicted impact of Fl is greater than the significant monitoring concentration, the Department is not requiring preconstruction monitoring for this project because there are no EPA-approved monitoring methods for Fl.

The Florida Sugar Cane League (FSCL) has operated an ambient monitoring network in the sugar cane growing area for several years. The network contains one continuous ambient SO_2 monitor, located at the Florida Celery Exchange in Belle Glade. This site is about 15 km southwest of the Osceola sugar mill and the data satisfy the preconstruction monitoring requirements for SO_2.

The second highest 3-hour and 24-hour and highest annual average SO_2 concentrations measured at the Belle Glade monitor during period 1991-1993 were used. Based on this analysis, the background SO_2 concentrations were determined to be 34 and 16 ug/m^3 for 3- and 24-hour averaging periods, respectively, and 5 ug/m^3 for the annual averaging period.

c. Modeling Procedure

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used to evaluate the pollutant emissions from the proposed facility 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 ISCST2 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 because the stacks were less than the good engineering practice (GEP) stack height.

For the PSD Class I analysis, the ISCST2 model was used initially as a screening model for estimating impacts on the Everglades National Park. For a more refined impact assessment

on the Everglades National Park, the MESOPUFF II model was used. This model is more appropriate for long-range transport applications where receptors are located more than 50 km from a source.

Initially, for the significant impact analysis, concentrations were predicted at 252 receptors located in a radial grid centered on the proposed stacks for the new cogeneration units. Receptors were located in "rings", with 36 receptors per ring spaced at 10-degree intervals at distances of 7, 11, 14, 20, 30, 40, 50 and 60 km. For the AAQS and PSD Class II analyses both near- and far- field receptor grid were used. The near-field screening included 36 receptors for each 10 degree sector located on the following rings: at the plant property; 2, 4, and 6 km in the directions outside plant property (distance to property boundary varies greatly by sector); and 8, 11, 14, 17, and 20 km. The far-field screening grid included five rings of receptors at distances of 25, 30, 40, 50 and 60 km. In addition, a detailed screening grid was used in the AAQS analysis. This grid was centered on the near-field screening receptor at 270 degrees and 6 km.

The Everglades National Park is a PSD Class I area that is located approximately 120 km south of the Osceola Power plant site. In the screening analysis, Everglades National Park is represented by 51 discrete receptors, including 47 receptors covering the eastern and northern boundaries of the park from the Florida Keys to the Gulf of Mexico and 4 receptors inside the northeast corner of the Park.

Meteorological data used in the ISCST2 model to determine air quality impacts 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. The 5-year period of meteorological data was from 1982 through 1986. The NWS station at West Palm Beach, located approximately 60 km east of the Osceola Power site, 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 plant site. The surface observations included wind direction, wind speed, temperature, cloud cover and cloud ceiling.

Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

For MESOPUFF II, 1983 meteorological data from the National Weather Service (NWS) stations located within or near the grid were used in the analysis. This year corresponds to the same year during which air dispersion modeling with the ISCST2 model indicated one 24-hour concentration in excess of 5.0 ug/m^3 in the Class I area. Upper air radiosonde data for 1983 from the Ruskin and West Palm Beach upper air NWS stations were used. These stations were selected because they are the nearest upper air stations to the study area. The surface meteorological data for 1983 were obtained from the following NWS stations, all located within the grid: (1) West Palm Beach, (2) Miami, and (3) Fort Myers. Hourly precipitation data were not used for any of the above surface meteorological stations. Land use data were developed for this grid from existing data developed by Argonne National Laboratory.

d. Significant Impact Analysis

The maximum air quality impacts from the proposed Osceola Power facility only are presented in Table 3. As shown, the facility's maximum annual, 24-hour, and 3-hour predicted SO_2 concentrations are 5.1, 66, and 183 ug/m^3, respectively. These maximum impacts are above the respective SO_2 significant impact levels of 1, 5, and 25 ug/m^3. Therefore, a full impact assessment was performed for SO_2.

e. PSD Increment Analysis

1. Class II Area

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. Based on the screening results, a refined modeling analysis was performed for each averaging time. The results, summarized in Table 4, indicate that the maximum SO_2 PSD increment consumption will not exceed the allowable PSD increments.

2. Class I Area

The Everglades National Park is a PSD Class I area that is located farther than 100 km from the Osceola Power plant site. The northeastern corner of this Class I area is approximately 120 km south of the Osceola Power site.

A screening analysis using the ISCST2 model shows that the proposed facility along with other increment consuming sources in

the area will meet the allowable annual and 3-hour PSD increments in the Class I area. However, the screening analysis shows that the 24-hour Class I increment of 5 ug/m^3 will be slightly exceeded. Based on the ISCST2 results, a refined air quality analysis was performed with the MESOPUFF II long-range transport model. These results show that the maximum predicted impacts for all increment-consuming sources is 4.10 ug/m^3 or less, which is below the allowable 24-hour PSD increment of 5 ug/m^3.

The summarized results are shown in Table 5.

f. AAQS Analysis

For the pollutants subject to an AAQS review, the total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The 1991 -1993 monitoring results from Belle Glade were used to determine the background SO_2 concentrations. The results of the AAQS analysis are summarized in Table 6. Emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

g. Air Toxics Analysis

The maximum impacts of regulated and non-regulated toxic air pollutants that will be emitted by the Osceola Power facility are presented in Table 7. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to Department's Ambient Reference Concentrations. The table shows that all toxic pollutant impacts will be below their respective reference concentrations, except for arsenic (As) for the annual averaging time.

For As the maximum predicted impacts are based on using a conservative assumption that 2.4 percent of the wood waste to be received at the facility would contain treated wood. Treated wood that contains chromium copper arsenate has an arsenic (As) emission factor that is higher than clean wood waste. However, the area predicted to exceed the acceptable ambient concentration for arsenate is within 4.0 km of the proposed facility. There are no public or private dwellings located in this area. Pursuant to Palm Beach County's conditions, all contracts with wood waste suppliers will contain a provision that the wood waste must be free from treated wood. In addition, the Department has added a condition that the applicant will visually inspect the waste wood supplied and will not knowingly burn any containing any treated wood. These conditions will minimize the potential for treated wood to be present in the wood waste, which will reduce the potential for As to be present.

h. Additional Impacts Analysis

1. Impacts on Soils, Vegetation, and Wildlife

The maximum ground-level concentration predicted to occur in the vicinity of the facility for SO_2 as a result of the proposed project, including a background concentration, will be below the national secondary standard which was developed to protect public welfare-related values. 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.

2. Impact on Visibility

Visual Impact Screening and Analysis (VISCREEN), the EPA-approved Level I visibility computer model, was used to estimate the impact of the proposed facility's stack emissions on visibility in the Everglades National Park.

The results indicated that the maximum visibility impacts caused by the facility do not exceed the screening criteria inside or outside the Everglades National Park Class I area. As a result, there is no significant impact on visibility predicted for the Class I area.

3. Growth-Related Air Quality Impacts

There will be a small number of temporary construction workers during construction. There will be about 20 permanent employees at Osceola Power associated with the operation of the cogeneration facility. These increases are minor, and there will be no significant impacts on air quality caused by associated population growth.

4. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 meters (213 feet) or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less.

The boiler building are the significant structures associated with the proposed cogeneration facility. The buildings have a height of 123 feet and a total combined width of 138 feet. From the above formula, the GEP stack height is 123+(1.5x123)=308 feet. The two stacks for the proposed facility will be 200 feet high and therefore do not exceed the GEP stack height. The

Table 1: Significant and Net Emission Rates (Tons per Year)

Pollutant	Proposed Net Emissions Increase	Significant Emission Rate	Applicable Pollutant (Yes/No)
TSP	-213.5	25	No
PM_{10}	-182.9	15	No
SO_2	160.5	40	Yes
NO_x	39.3	40	No
CO	-4,555.9	100	No
VOC	10.6	40	No
Lead	-0.15	0.6	No
Mercury	0.001	0.1	No
Beryllium	0.00128	0.0004	Yes
Fluorides	5.24	3	Yes
Sulfuric Acid Mist	0.64	7	No
TRS	0	10	No
Asbestos	0	0.007	No
Vinyl Chloride	0	0	No

Table 2. Maximum Air Quality Impacts for Comparison to the De Minimus Ambient Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m^3)	De Minimus Level (ug/m^3)
SO_2	24-hour	66	13
Beryllium *	24-hour	0.00036	0.001
Fluorides *	24-hour	1.46	0.25

* non-criteria pollutant

Table 3. Maximum Air Quality Impacts for Comparison to the Significant Impact Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)
SO_2	Annual	5.1	1
	24-hour	66	5
	3-hour	183	25

Table 4. PSD Class II Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	10.7	20
	24-hour	76	91
	3-hour	191	512

Table 5. PSD Class I Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Allowable Increment (ug/m^3)
SO_2	Annual	0.60	2
	24-hour	4.10	5
	3-hour	22.8	25

Table 6. Ambient Air Quality Impact

Pollutant	Averaging Time	Major Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Total Impact (ug/m^3)	Florida AAQS (ug/m^3)
SO_2	Annual	33	5	38	60
	24-hour	208	16	224	260
	3-hour	1059	34	1093	1,300

Table 7: Air Toxics Analysis

	8- hour		24- hour		Annual	
Pollutant	Impact (ug/m^3)	ARC (ug/m^3)	Impact (ug/m^3)	ARC (ug/m^3)	Impact (ug/m^3)	ARC (ug/m^3)
Acetaldehyde	0.12	1800	0.069	432	0.0048	0.45
Acetone	0.061	36500	0.033	8544	-	-
Acetophenone	-	-	-	-	2.24e-05	100
Acrolein	0.010	2.3	0.0057	0.552	0.00040	0.02
Ammonia	5.32	170	2.93	40.8	0.20	100
Antimony	0.0039	5	0.0021	1.2	0.00015	0.3
Arsenic	0.021	2	0.012	0.48	0.00026	0.00023
Barium	0.0082	5	0.0045	1.2	0.00031	50
Benzene	0.21	30	0.11	7.2	0.0079	0.12
Benzo(a)anthracene	-	-	-	-	4.57e-06	0.0011
Beryllium	0.00065	0.02	0.00036	0.0048	2.48e-05	0.00042
Bromine	0.0084	6.6	0.0046	1.584	-	-
Cadmium	0.00014	0.5	7.50e-05	0.12	5.21e-06	0.00056
Carbon Disulfide	0.021	310	0.012	74.4	0.00080	200
Carbon Tetrachloride	0.00095	310	0.00052	74.4	3.65e-05	0.067
Chlorine	0.15	15	0.081	3.6	0.0056	0.4
Chloroform	0.0074	490	0.0041	117.6	0.00028	0.043
Chromium	0.025	5	0.14	1.2	-	-
Chromium+6	0.0050	0.5	0.0028	0.12	6.41e-05	8.3e-05
Cobalt	0.0080	0.5	0.0044	0.12	-	-
Copper	0.020	10	0.011	2.4	-	-
Cumene	0.0028	2460	0.0016	590.4	0.00011	1
Di-n-Butyl phthalate	0.0092	50	0.0051	12	0.00035	100
Ethyl Benzene	0.00062	4340	0.00034	1042	2.36e-05	1000
Fluoride	2.65	25	1.46	6	-	-
Formaldehyde	0.21	12	0.11	2.88	0.0079	0.77
Hydrogen Chloride	8.78	75	4.83	18	0.34	7
Indium	0.021	1	0.012	0.24	-	-

Iodine	0.00034	10	0.00018	2.4	-	-
Isopropanol	1.47	9830	0.81	2539	-	-
Lead	0.00057	0.5	0.00031	0.12	0.00027	0.09
Manganese	0.015	50	0.0081	12	-	-
Mercury	0.00094	0.5	0.00052	0.12	3.53e-05	0.3
Methanol	0.24	2620	0.132	628.8	-	-
Methyl Ethyl Ketone	0.0019	5900	0.0010	1416	7.21e-05	80
Methyl Isobutyl Ketone	0.14	2050	0.076	492	-	-
Methylene Chloride	0.24	1740	0.13	417.6	0.0091	2.1
Molybdenum	0.00099	50	0.00054	12	-	-
n Hexane	0.088	1760	0.048	422.4	0.0034	200
Napthalene	0.094	520	0.052	124.8	-	-
Nickel	0.0012	10	0.00063	2.4	4.41e-05	0.0042
o Xylene	0.00042	4340	0.00023	1042	1.60e-05	80
Phenols	0.0065	190	0.0036	45.6	0.00025	30
Phosphorus	0.10	1	0.052	0.24	-	-
Selenium	0.0060	2	0.0033	0.48	-	-
Silver	0.00023	1	0.00013	0.24	8.81e-06	3
Styrene	0.0024	2130	0.0013	511.2	-	-
Sulfuric Acid Mist	1.11	10	0.61	2.4	-	-
Tin	0.00099	20	0.00054	4.8	-	-
Toluene	0.015	3770	0.0081	898	0.00056	300
2,3,7,8 Tetrachlorodibenzo-p-dioxin	-	-	-	-	3.65e-11	2.2e-08
Trichloroethylene	0.0013	2690	0.00069	645.6	-	-
1,1,1 Trichloroethane	0.027	38200	0.015	9168	-	-
Tungsten	2.05e-06	50	1.13e-06	12	-	-
Vanadium	2.31e-05	0.5	1.27e-05	0.12	8.81e-07	20
Yttrium	1.05e-05	10	5.77e-06	2.4	-	-
Zirconium	6.50e-05	50	3.58e-05	12	-	-

Note: ARC = Ambient Reference Concentration

potential for downwash of the emissions from the facility due to the presence of nearby structures was considered in the modeling study.

V. Conclusion

Based on the information provided by Osceola Power Limited Partnership, the Department has reasonable assurance that the proposed construction/installation of the 74 MW (in lieu of 60 MW) cogeneration facility, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 62-212 of the Florida Administrative Code.

aaf 7/27

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
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Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

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

Permit Number: AC50-269980
PSD-FL-197A
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 Chapters 62-210, 212, 272, 275, 296, and 297, and 62-4, Florida Administrative Code (F.A.C.). 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 74 (gross) megawatt (MW), electrical power, (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 760 million British thermal units per hour (MMBtu/hr) on biomass, 600 MMBtu/hr on No. 2 fuel oil, and 530 MMBtu/hr on coal. Each boiler will produce approximately 506,000 lbs/hr of steam at 1,540 pounds per square inch gauge (psig) and 955°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 a 15,000 gallon No. 2 fuel oil storage tank, feed and ash handling systems, steam turbines and condensers, electrical power generators, cooling towers, and stacks that are 8.0 ft. in diameter and, a minimum 200 ft. high.

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

This permit replaces permit AC50-219795/PSD-FL-197.

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 April 26, 1995.
2. DEP permit No. AC50-219795/PSD-FL-197.

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 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

GENERAL CONDITIONS:

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 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.

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

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

13. This permit also constitutes:

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

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

GENERAL CONDITIONS:

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

SPECIFIC CONDITIONS:

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application or permit. The facility shall be designed, constructed, and operated so that its gross generating capacity shall not exceed 74 megawatt (MW), 1 hour average, except during scheduled emission compliance and equipment performance tests. Equipment performance testing in excess of 74 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 760 million British thermal units per hour (MMBtu/hr) with biomass fuel, 600 MMBtu/hr with No. 2 fuel oil, and 530 MMBtu/hr with coal.

3. Each boiler shall have an individual stack, and each stack must have a minimum height of 200 feet. The stack sampling facilities for each stack must comply with Rule 62-297.345, F.A.C.

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 99 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.

SPECIFIC CONDITIONS:

6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_x), sulfur dioxide (SO_2), oxygen (O_2), and carbon monoxide (CO). The monitoring devices shall meet the applicable requirements of Rule 62-296.405, 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.

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 matter 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.

SPECIFIC CONDITIONS:

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

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

Operational and Emission Restrictions

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application or permit. The facility shall not exceed 74 (gross) megawatts generating capacity, 1 hour average, except during emission compliance and equipment 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 760 MMBtu/hr when burning 100 percent biomass, 600 MMBtu/hr when burning 100 percent No. 2 fuel oil, or 530 MMBtu/hr when burning low sulfur coal. Maximum heat input to the entire facility (total of two boilers) shall not exceed 8.208 x 10^{12} Btu per year. Steam production of each boiler shall not exceed an average of 506,000 lbs/hr at 1,540 psig, 955°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 biomass 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 Department's Acceptable Ambient Concentration (AAC). The wood waste shall not contain more than 56.7 parts per million (ppm) arsenic or 67.3 ppm chromium or 53.2 ppm copper based on analysis of a composite sample of the fuel.

SPECIFIC CONDITIONS:

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.

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 lbs SO_2/MMBtu.

15. 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. The consumption of low sulfur coal shall not exceed 5.4 percent of the total heat input to each boiler unit in any calendar quarter. The plant shall not burn more than 18,221 tons of coal during any 12-month period (12-month rolling average).

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

SPECIFIC CONDITIONS:

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. **AC** 50-203679, 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.

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

SPECIFIC CONDITIONS:

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 760 MMBtu/hr for biomass fuels and 600 MMBtu/hr for No. 2 fuel oil, and 530 MMBtu/hr for 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	22.8	0.03	18.0	0.03	15.9	123.1
Particulate (PM_{10})	0.03	22.8	0.03	18.0	0.03	15.9	123.1
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	636.0	---
24-hour average	0.10	76.0	0.05	30.0	1.2	636.0	---
Annual average	0.02[a]	---	---	---	1.2[a]	---	339.0[f]
Nitrogen Oxides							
Annual average	0.12[a]	88.2[a]	0.12[a]	72.0[a]	0.15[a]	79.5[a]	477.1
Carbon Monoxide							
8-hour average	0.35	266.0	0.2	120.0	0.2	106.0	1,436.4
Volatile Organic Compounds	0.06[b] 0.04[c]	45.6[b] 30.4[c]	0.03	18.0	0.03	15.9	219.2
Lead	2.7×10^{-6}	0.002	8.9×10^{-7}	0.0005	5.1×10^{-6}	0.0027	0.011
Mercury	5.7×10^{-6}[b] 0.29×10^{-6}[c]	0.0043[b] 0.00022[c]	2.4×10^{-6}	0.0014	8.4×10^{-6}	0.0045	0.0168

SPECIFIC CONDITIONS:

Beryllium	---	---	3.5×10^{-7}	0.0002	5.9×10^{-6}	0.0031	0.0013
Fluorides	---	---	6.3×10^{-6}	0.004	0.024	12.7	5.25
Sulfuric Acid Mist	0.005	3.72	0.0025	1.5	0.010	5.3	6.0

[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 18,221 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 Rule 62-296.210, F.A.C. 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.

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

SPECIFIC CONDITIONS:

Department, in accordance with F.A.C. Rule 62-297.620. 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.
104	Determination of beryllium emissions from stationary sources.

SPECIFIC CONDITIONS:

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 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.

SPECIFIC CONDITIONS:

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 62-297.500, F.A.C. The permittee shall comply with all applicable requirements in 40 CFR 60, Subpart Ka, for the No. 2 fuel oil storage tank.

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 62-4.090).

27. A timely application for a Title V permit to operate shall be submitted to the Palm Beach County air program administrator by the date specified in chapter 62-213, F.A.C.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell, Secretary
Department of Environmental Protection

Best Available Control Technology (BACT) Determination
Osceola Power Limited Partnership
Palm Beach County
AC50-269980 (PSD-FL-197A)

The applicant proposes to construct a 74 MW (net) of electricity cogeneration facility consisting of two 760 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. 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 (Rule 15.4-212.400, F.A.C.). 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 in the original application for this facility 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 0.70 percent sulfur. Also, limiting the total No. 2 fuel oil burned in the boilers to 25 percent of the annual heat input, limiting the amount of coal burned at the facility to 18,221 tons during any 12-month period, limiting the combination of coal and oil burned in the boilers to 25 percent of the annual heat input, and limiting the sulfur dioxide emissions to 338.99 TPY is a condition 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 5.4 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	0.10/76.0	0.05/30.0	1.2/636.0
Beryllium	--	3.5E-7/2.0E-4	5.9E-6/3.1.E-3
Fluorides	--	6.3E-6/3.8E-3	2.4E-2/12.7

* Maximum heat input per boiler

Biomass - 760 MMBtu/hr
No. 2 fuel oil - 600 MMBtu/hr
Coal - 530 MMBtu/hr

BACT Determination Procedure

In accordance with Rule 62.4-212.410, F.A.C., 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 DEP

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)	Low sulfur fuel (0.05 percent max. for No. 2 fuel oil; 0.70 percent max. for coal); max. annual heat input of 25 percent from No. 2 fuel oil; a max. 18,221 TPY coal burned; a max. annual heat input of 25 percent on a calendar quarter basis for oil and coal; and 5.4 percent for coal, and limiting sulfur dioxide emissions to 339 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, 5.4 percent of the heat input for coal, less than 25 percent of the heat 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. annual heat input of 25 percent on a calendar quarter basis from No. 2 fuel oil, 5.4 percent coal, less than 25 percent on a calendar year 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 25 percent of the total annual heat input for the boilers. Thus, 75 percent of the annual 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 339 TPY, will occur when 5.4 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 (18,221 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 1,493 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 5.1, 66, and 183 ug/m^3 for the annual, 24-hour, and 3-hour time periods, respectively.

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 6.2E-3 lbs/hr. The ambient air impact of this emission will be 6.5E-4, 3.6E-4, and 2.5E-5 ug/m^3 for the 8-hour, 24-hour and annual time periods, respectively. These impacts are below the Air Toxics Reference Concentration (ATRC), 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 18,221 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 12.72 lbs/hr fluorides, the 8-hour and 24-hour impacts are 2.7 and 1.5 ug/m^3. These impacts are below the ATRC.

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 ATRCs for these pollutants.

Details of the Analysis May be Obtained by Contacting:

A. A. Linero, P.E., Administrator NSR
Willard Hanks, Review Engineer
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 Protection

_____ 1995
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

_____ 1995
Date

Reasonably Available Control Technology (RACT) Determination
Osceola Power Limited Partnership
Palm Beach County
AC50-269980 (PSD-FL-197A)

The applicant proposed to construct a 74 MW (gross, 1-hour average) electric cogeneration facility consisting of two 760 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 (219.2 TPY) and nitrogen oxides (477.1 TPY). However, the net contemporaneous emission change for these pollutants resulting from the cogeneration facility project, an increase of 10.6 TPY for VOC and 39.3 TPY for NO_X, is less than the significant emission rates, Table 212.400-2, F.A.C. Thus, the project is subject to Rule 62-296.570, F.A.C., 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, 0.04 lbs/MMBtu on wood, 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 0.15 lbs/MMBtu for coal firing.

RACT Determination Procedure

In accordance with Rule 62-296.570, F.A.C., 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		0.15	

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.

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 attainment/maintenance area.

Details of the Analysis May be Obtained by Contacting:

A. A. Linero, P.E., Administrator NSR
Willard Hanks, Review Engineer
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 Protection

_____ 1995
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

_____ 1995
Date

Florida Department of
Environmental Protection

Memorandum

To: Clair Fancy

From: Willard Hanks wmh

Date: July 27, 1995

Subject: Osceola Power L.P.
AC 50-269980/PSD-FL-197A

Attached for your approval and signature is an intent to issue a construction permit for a modified project consisting of a biomass cogeneration facility that will be located with a sugar mill in Palm Beach County.

Osceola Power L.P. was issued a construction permit to build a 60 MW cogeneration facility in 1993. Biomass is the primary fuel. Fossil fuel, coal and oil, may also be burned in the boilers. Emissions are controlled by an electrostatic precipitator, SCNR system, and carbon injection. The permit was amended to allow 65 MW production with no increase in emissions. The permittee selected equipment that is capable of producing 74 MW of power with a corresponding increase in emissions. A new application to replace the 65 MW unit with a 74 MW was submitted. As this is a new source under construction, I chose to issue a new permit instead of modifying the existing permit. Al Linero determined that the public notice for a modified project was appropriate. This insures that the scope of the new entry point will only relate to issues raised by the modification itself.

The 90th day for this application is August 2, 1995. I recommend your approval of the new proposal.

Attachment

CF/al/s