Florida Department of
Environmental Protection

Memorandum

BAR

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero

FROM: Edward J. Svec

DATE: June 24, 1999

SUBJECT: Florida Power Corporation
Crystal River Power Plant
Coal/Briquette Mixture

Attached for approval and signature is Permit No. 0170004-006-AC, a modification of Permit No. 0170004-003-AC and PSD-FL-007. This project allows the combustion of a mixture of coal and briquettes. The briquettes are formed from coal fines bound by fuel oil. Florida Power Corporation requested fuel sulfur content limits on the coal/briquette mixture shipments such that there will be no increase in actual emissions of sulfur dioxide from coal fired Units 1,2 4 and 5. The Public Notice requirements have been met on June 3, 1999 by publishing in the Citrus County Chronicle. Proof of Publication was received on June 24, 1999.

I recommend your approval and signature.

Attachments

/es

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 29, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffery Pardue
Director, Environmental Services Department Director, Environmental Services Department
Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

Re: DEP File No. 0170004-006-AC, Modification of Permit No. 0170004-003-AC, PSD-FL-007
Crystal River Power Plant

The applicant, Florida Power Corporation, Crystal River Power Plant, applied on March 24, 1999, to the Department for a modification to air construction permit number 0170004-003-AC for its Crystal River Power Plant located west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The modification is to include a coal/briquette mixture as an allowable fuel in Crystal River Units 1,2,4, and 5. The briquettes will be blended with some of the regular coal supply and Florida Power Corporation states the sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

OPERATIONAL REQUIREMENTS

1. Hours of Operation: These emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]
2. Fuel: The emissions units described above may combust a mixture of coal and coal briquettes. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

3. Sulfur Limitation: The maximum sulfur content of the coal/ briquette mixture shipment, averaged on an annual basis, shall not exceed the following:[Requested by Applicant in the application received March 24, 1999]

Emissions Unit No.	Emissions Unit Description	Average Percent Sulfur Limit, By Weight
001	Fossil Fuel Steam Generator (FFSG), Unit 1	1.05%
002	FFSG, Unit 2	1.05%
004	FFSG, Unit 4	0.68%
003	FFSG, Unit 5	0.68%

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

4. The permittee shall demonstrate compliance with the fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. See specific conditions 3 and 5.
[Rule 62-213.440, F.A.C.]

5. Sulfur Dioxide - Fuel Sampling. The following fuel sampling and analysis program shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the fuel sulfur standard:
a. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using appropriate ASTM methods such as, ASTM D2013-72, ASTM D3177-75, and ASTM D4239-85, or latest ASTM edition methods, to analyze a representative sample of coal following each fuel delivery.
b. Record daily the amount of coal fired, the density of each fuel, the Btu value, and the percent sulfur content by weight of each fuel.
c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.
[Rule 62-213.440, F.A.C.]

6. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

7. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
[Rule 62-213.440(1)(b)2.b., F.A.C.]

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources
Management

Florida Power
CORPORATION

February 22, 1999

Mr. Al Linero, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Coal "Briquettes" Fuel

As you know from previous correspondence, Florida Power Corporation (FPC) has been approached by its fuel supplier, Electric Fuels Corporation, conceming the possibility of burning "coal briquettes" at its Crystal River plant. The briquettes are produced from coal fines at the mines that currently supply the coal for Crystal River Units 1, 2, 4, and 5. Coal fines are combined under heat and pressure with a small amount of oil (maximum of 5% Bunker C oil) at the mine. The oil is the binding agent for the coal fines. Subjecting the coal fines to heat and pressure removes moisture and produces the coal briquettes, which are small chunks of coal that can be handled and burned with the regular coal supply.

The following table shows the average sulfur content of the coal supplies burned in Units 1 and 2, and in Units 4 and 5. The averages are based on daily coal samples averaged over the calendar year and have been reported in the Annual Operating Reports for these units.

	1996	1997	1998	Average
Units 1 and 2	1.03%	1.07%	1.05%	1.05%
Units 4 and 5	0.68%	0.67%	0.69%	0.68%

FPC would receive the briquettes in shipments blended with some of the regular coal supply. In order to ensure that the addition of coal briquettes does not result in an increase in emissions due to the sulfur content of the Bunker C oil, FPC is willing to commit to limiting the sulfur content of these shipments. The sulfur content, as averaged on an annual basis, of the shipments of briquettes combined with coal, will not exceed 1.05% for Units 1 and 2, and will not exceed 0.68% for Units 4 and 5.

Use of the briquettes as fuel is an environmentally beneficial way of utilizing the coal fines resulting from the mining process. If not used as fuel, the fines would otherwise be discarded. Limiting the sulfur content of the fuel to historical levels ensures that no emissions increase will result.

FPC requests that the DEP add "coal briquettes" to the list of fuels authorized to be burned in units 1, 2, 4, and 5, subject to the sulfur content limitation. This limit would apply to the annual average sulfur content of the shipments received of briquettes combined with coal. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services
FPC Responsible Official

Al's copy -

RECEIVED

MAR 24 1999

BUREAU OF
AIR REGULATION

Florida Power
CORPORATION

March 22, 1999

Mr. Al Linero, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

0170004-006-AC

Re: Coal "Briquettes" Fuel

As we discussed in Tallahassee last week, I have enclosed a P.E. seal and application processing fee check for the "coal briquettes" permit application for the Florida Power Corporation (FPC) Crystal River plant. For your convenience, there are two originals of the P.E. seal page enclosed.

Thank you for your prompt processing of this request. Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

4. Professional Engineer Statement:

*I, the undersigned, hereby certify, except as particularly noted herein**, *that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [✓] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Kent D. Hedrick 3/23/99 Kent D. Hedrick

Signature Date

(seal) FL PE# 50474

* Attach any exception to certification statement.

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6-30-99 to the person(s) listed:

* W. Jeffrey Pardue, Florida Power Corporation
Mike Kennedy, Florida Power Corporation
Gerald Kissel, P.E., DEP, Southwest District
Hamilton S. Oven, P.E., DEP

Clerk Stamp

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

Kim Tobin 6-30-99
(Clerk) (Date)

FINAL DETERMINATION

Florida Power Corporation
Crystal River Power Plant
Citrus County
Coal/Briquette Fuel Mixture

Permit No. 0170004-006-AC

An "Intent to Issue an Air Construction Permit" to allow the combustion of a coal/briquette fuel mixture to Florida Power Corporation for the Crystal River Power Plant located west of U. S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County was clerked on May 25, 1999. The "Public Notice of Intent to Issue Air Construction Permit" was published in the Citrus County Chronicle on June 3, 1999. The draft Air Construction Permit was available for public inspection at the Department of Environmental Protection's Southwest District office in Tampa and the permitting authority's office in Tallahassee. Proof of publication of the "Public Notice of Intent to Issue Air Construction Permit" was received on June 24, 1999.

Comments were received and the draft Air Construction Permit was changed. The comments were not considered significant enough to reissue the draft Air Construction Permit and require another Public Notice. Comments were received from one respondent, Mr. J. Michael Kennedy of Florida Power Corporation, during the 14 (fourteen) day public comment period. Listed below is each comment and the response.

Condition 3. Sulfur Limitation.

Comment: Could we add the word "shipments" after the word "mixture" to ensure that it's clear that we're talking about the shipments we receive (as opposed to the separate regular coal shipments)? It is written that way in the Technical Evaluation, so reflecting it in the permit would be consistent.

Response: The Department agrees with the comment and will add the word "shipments" after the word "mixture".

Comment: In the table, Emissions Unit No. 3 is actually FFSG, Unit 5. Unit 3 is the nuclear unit.

Response: The Department agrees with the comment and Emissions Unit 003 will identified as FFSG Unit 5.

Comment: The question the folks in fuel supply have asked is if we could write the sulfur limit in terms of lb/mmBtu for the coal/briquette shipments rather than %sulfur. They said that some of the coal we get is high in Btu content, and the lb/mmBtu approach would provide some flexibility without increasing the emission rate. What do you think?

Response: After Florida Power Corporation provides equivalency information, the Department will express the limits in terms of pounds per million Btu, heat input.

The final action of the Department will be to issue the permit covered by the public notice as proposed except for the changes noted above.

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Jeffrey Pardue
FPC
PO BOX 14042- BB1A
St. Pete, Fl
33711

4a. Article Number
Z 333 618 191

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

7. Date of Delivery
JUL 06 1999

5. Received By: *(Print Name)*
Dana Clark

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

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

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 618 191

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Jeff Pardue	
Street & Number FPC	
Post Office, State, & ZIP Code St. Pete Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 6-30-99 0170004-003-AC PSO-F1-007	

PS Form **3800**, April 1995

Proof Of Publication

from the

CITRUS COUNTY CHRONICLE

Crystal River, Citrus County, Florida

PUBLISHED DAILY

STATE OF FLORIDA
COUNTY OF CITRUS

Before the undersigned authority personally appeared FELICIA H. SATCHELL of the Citrus County Chronicle, a newspaper published daily at Crystal River, in Citrus County, Florida, that the attached copy of advertisement being a public notice in the matter of the

FILE NO. 0170004-006-AC

Court, was published in said newspaper in the issues of

JUNE 3, 1999

Affiant further says that the Citrus County Chronicle is a newspaper published at Crystal River in said Citrus County, Florida, and that the said newspaper has heretofore been continuously published in Citrus County, Florida, each week and has been entered as second class mail matter at the post office in Inverness in said Citrus County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Felicia H. Satchell

The forgoing instrument was acknowledged before me this 3th day of JUNE 19 99

by FELICIA H. SATCHELL

who is personally known to me and who did take an oath.

Jeanette A. Schmidt

Notary Public

Jeanette A Schmidt
Notary Public, State of Florida
Commission No. CC 669909
My Commission Exp. 08/16/2001
1-800-3-NOTARY - Fla. Notary Service & Bonding Co.

1420603 THCRN
PUBLIC NOTICE
OF INTENT TO ISSUE
AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL REGULATION
DEP File No. 0170004-006-AC
Florida Power Corporation
Crystal River Plant
Citrus County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Florida Power Corporation, for the Crystal River Plant located west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus. County. The permit is to allow the combustion of a coal/briquette fuel mixture in Crystal River Units 1, 2, 4 and 5. The applicant's mailing address is: Florida Power Corporation, 3201 34th Street South, St. Petersburg, Florida 33711. A Best Available Control Technology (BACT) determination was nor required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

The briquettes are produced from coal fines at the mines, currently supplying coast to Crystal River Units, 1, 2, 4 and 5. The coal fines are combined under heat and pressure with a small amount of oil to form the briquettes. The oil acts as a binding agent. The heat and pressure removes moisture and produces the briquettes. The briquettes will be blended with some of the regular coal supplied to Florida Power Corporation. The sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. Sulfur content of the mixture shall not exceed 1.05 %, percent by weight and annual average, for Crystal River Units 1 and 2; and 0.68 % percent by weight and annual average, for Crystal River Units 4 and 5. The combustion of this fuel mixture will result in no actual increases of sulfur dioxide.

This project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity.

Any air quality impact analysis was not conducted. Emissions from the facility will not consume PSD increment and will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The Department will issue the Final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of this Public Notice of Intent to issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station # 5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

Mediation is not available is this proceeding.

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

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100

The complete project file includes the application, technical evaluations, Draft permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Source Review Section, or the Department's reviewing engineer for this project, Edward J. Svec, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Published one (1) time in the Citrus County Chronicle: Thursday, June 3, 1999.

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Jeffrey Pardue
FPC
3201 34th St. South
St. Pete, Fl 33711

4a. Article Number
Z 333 618 153

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

7. Date of Delivery MAY 28 1999

5. Received By: *(Print Name)*

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

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

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

Thank you for using Return Receipt Service.

Z 333 618 153

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Jeff Pardue	
Street & Number FPC	
Post Office, State, & ZIP Code St. Pete Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-25-99 0170004-006AC	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
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I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. W. Jeffrey Pardue, Director
Environmental Services Dept.
Florida Power Corporation
P. O. Box 14042, MAC BBIA
Saint Petersburg, FL 33733-4042

4a. Article Number
P 263 584 898

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

7. Date of Delivery NOV 02 1998

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994 Domestic Return Receipt

Thank you for using Return Receipt Service.

P 263 584 898

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Mr. W. Jeffrey Pardue, Director
Environmental Services Dept.
Florida Power Corporation
P. O. Box 14042, MAC BBIA
Saint Petersburg, FL 33733-4042

Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 10-30-98	

PS Form **3800**, April 1995

EXTRA
COPIES
for reference?

Florida Power Corporation
Crystal River Plant
Facility ID No.: 0170004
Citrus County

Initial Title V Air Operation Permit
FINAL Permit No.: 0170004-004-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:
Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Initial Title V Air Operation Permit
FINAL Permit No.: 0170004-004-AV

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

Permittee:
Florida Power Corporation
263 13th Avenue South
St. Petersburg, FL 33701-5511

FINAL Permit No.: 0170004-004-AV
Facility ID No.: 0170004
SIC Nos.: 49, 4911
Project: Initial Title V Air Operation Permit

This permit is for the operation of the Crystal River Plant. This facility is located Power Line Road, West of U.S. Hwy. 19, Crystal River, Citrus County; UTM Coordinates: Zone 17, 334.3 km East and 3204.5 km North; Latitude: 28° 57' 34" North and Longitude: 82° 42' 1" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-3, Title V Conditions (version dated 04/30/99)
Appendix SS-1, Stack Sampling Facilities (version dated 10/07/96)
Appendix P, Sensitive Paper Sampling Locations and Apparatus
Table 297.310-1, Calibration Schedule (version dated 10/07/96)
Figure 1 - Summary Report-Gaseous And Opacity Excess Emission And Monitoring System Performance Report (version dated 7/96)
Phase II Acid Rain Application/Compliance Plan received 12/22/95
Phase I Acid Rain permit dated 3/27/97
Alternate Sampling Procedure: ASP Number 97-B-01
Order Granting Petition for Reduced Frequency of Particulate Testing, OGC Case No. 86-1576, Order dated December 12, 1986 (Emissions Unit 001)
Best Management Plan, KBN, November 1990
Figure A, Ambient Air Monitoring Locations, Crystal River, Florida

Effective Date: January 1, 2000
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

Howard L. Rhodes, Director
Division of Air Resources
Management

"More Protection, Less Process"

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Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of four coal-fired fossil fuel steam generating (FFSG) units with electrostatic precipitators; two natural draft cooling towers for FFSG Units 4 and 5; helper mechanical cooling towers for FFSG Units 1, 2 and Nuclear Unit 3; coal-, fly ash-, and bottom ash-handling facilities, and relocatable diesel fired generator(s). The nuclear unit (Unit 3) is not considered part of this permit, although certain emissions units associated with Unit 3 are included in this permit.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator (FFSG), Unit 1
002	FFSG, Unit 2
004	FFSG, Unit 4
003	FFSG, Unit 5
006	Fly ash transfer (Source 1) from FFSG Unit 1
008	Fly ash storage silo (Source 3) for FFSG Units 1 and 2
009	Fly ash transfer (Source 4) from FFSG Unit 2
010	Fly ash transfer (Source 5) from FFSG Unit 2
014	Bottom ash storage silo for FFSG Units 1 and 2, with associated vacuum blower exhausts and bin vent filter (total of three emission points)
7775047, 001	Relocatable diesel generator(s) will have a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts.
013	Cooling towers for FFSG Units 1, 2, and 3, used to reduce plant discharge water temperature
015	Cooling towers for FFSG Units 4 and 5 used to reduce plant discharge water temperature
016	Material handling activities for coal-fired steam units

Unregulated Emissions Units and/or Activities	
017	Fuel and lube oil tanks and vents
018	Sewage treatment, water treatment, lime storage
019	Two 3500 kW diesel generators associated with Unit 3

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

Documents on file with USEPA
Risk Management Plan submitted to the RMP Reporting Center on 06/21/99 (received date).

These documents are on file with the permitting authority:
Initial Title V Permit Application received June 14, 1996
BACT Determination dated 8/29/90 (Cooling Tower Drift Emission Rate)
BACT Determinations ordered 2/5/79 (proposed 1/26/79) and 8/16/79 (Fly Ash Transfer)
Revision to Permit Application received April 17, 1998
Letter received November 9, 1998, from Mr. Scott Osbourn.
Letter received August 2, 1999, from Mr. J. Michael Kennedy

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-3, TITLE V CONDITIONS is a part of this permit.
{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not Federally Enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited.
The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard.
Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4, F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. As required by Section 112(r)(7)(B)(iii) of the CAAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAAA.
c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:

Cashier
Department of Community Affairs
State Emergency Response Commission
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6), and 62-4.040(1)(b), F.A.C.]

7. Not Federally Enforceable. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. The owner or operator shall:

a. Tightly cover or close all VOC or OS containers when they are not in use.
b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.
d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996]

8. Not Federally Enforceable. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility may include, as needed:

a. Maintenance of paved areas as needed.
b. Regular mowing of grass and care of vegetation.
c. Limiting access to plant property by unnecessary vehicles.

[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996]

9. When appropriate any recording, monitoring or reporting requirements that are time-specific shall be in accordance with the effective date of this permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southwest District office:

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6458

Any reports, data, notifications, certifications and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPRCA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, GA 30303
Phone: 404/562-9155
Fax: 404/562-9163

11. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. ***This section addresses the following emissions units.***

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1: a tangentially fired unit, rated at 440.5 MW, 3750 MMBtu/hr, burning bituminous coal; or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. Emissions are exhausted through a 499 ft. stack. This unit may also burn oily flyash.
002	Fossil Fuel Steam Generator, Unit 2: a tangentially fired unit, rated at 523.8 MW, 4795 MMBtu/hr, burning bituminous coal; or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. Emissions are exhausted through a 502 ft. stack. This unit may also burn oily flyash.

Fossil Fuel Steam Generators, Units 1 and 2, are pulverized coal dry bottom boilers, tangentially-fired. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc.

{Permitting Notes: These emissions units are regulated under Acid Rain, Phase I and II and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input, and Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 1 began commercial operation in 1966. Fossil fuel fired steam generator Unit 2 began commercial operation in 1969.}

The following specific conditions apply to the emissions unit(s) listed above:

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	3750	Bituminous Coal; or Bituminous Coal and Bituminous Coal Briquette Mixture
002	4795	Bituminous Coal; or Bituminous Coal and Bituminous Coal Briquette Mixture

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **I.11**.
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned by this permit are: bituminous coal; a bituminous coal and bituminous coal briquette mixture, and distillate fuel oil for startup. These emissions units may also burn used oil in accordance with other conditions of this permit (see **Subsection K**). Emissions units 001 and 002 may also burn oily flyash in accordance with specific condition **A.16** of this permit.
[Rule 62-213.410, F.A.C.; 0170004-002-AO; 0170004-005-AO; and, 0170004-006-AC]

Emission Limitations and Standards

A.4.a. Visible Emissions - Emissions Unit 001. Visible emissions shall not exceed 40 percent opacity, six minute average. Emissions units governed by this visible emissions standard shall compliance test for particulate matter emissions annually.
[Rule 62-296.405(1)(a), F.A.C.; and OGC Case No. 86-1576, Order dated December 12, 1986.]

A.4.b. Visible Emissions - Emissions Unit 002. Visible emissions shall not exceed 20 percent opacity, six minute average, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rule 62-296.405(1)(a), F.A.C.]

A.5. Visible Emissions - Soot Blowing and Load Change. Excess emissions from existing fossil fuel steam generators resulting from boiler cleaning (soot blowing) and load change shall be permitted provided the duration of such excess emissions shall not exceed 3-hours in any 24 hour period and visible emissions shall not exceed Number 3 of the Ringelmann Chart (60 percent opacity), six minute average, and providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of the excess emissions shall be minimized.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition, for boiler cleaning and load changes, at units which have installed and are operating continuous opacity monitors.
[Rule 62-210.700(3), F.A.C., Note: these units have operational continuous opacity monitors.]

A.6. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input , as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

A.7. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

{Permitting note: The averaging time for the particulate matter standard corresponds to the cumulative sampling time of the specified test method.}

A.8. Sulfur Dioxide. The maximum sulfur dioxide emissions from the coal/briquette mixture shipment, averaged on an annual basis, shall not exceed the following:

Emissions Unit No.	Emissions Unit Description	Average Sulfur Dioxide Limit, in Pounds Per Million Btu, Heat Input
001	FFSG, Unit 1	1.67
002	FFSG, Unit 2	1.67

[Rule 62-213.440, F.A.C.; PPSC PA 77-09; and, 0170004-006-AC]

{Permitting note: The sulfur dioxide limit of the coal and coal briquette mixture is based on an annual average sulfur content of 1.05%, by weight, and an average heat content of 25.17 million Btu per ton of coal.}

{Permitting note: The averaging time for the particulate matter standard corresponds to the cumulative sampling time of the specified test method.}

Test Methods and Procedures

A.9. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17 or 5 incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

A.10. Visible Emissions. The test method for visible emissions shall be EPA Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.
[Rules 62-296.405(1)(e)1. and 62-297.401, F.A.C.]

A.11. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee may demonstrate compliance using fuel sampling and analysis.** If the permittee elects to discontinue fuel sampling and analysis, it shall perform a stack test for sulfur dioxide at the time of the next particulate matter test, and annually thereafter until fuel sampling and analysis is resumed.
[Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.]

A.12. Sulfur Dioxide. The owner or operator may demonstrate compliance with the sulfur dioxide limitation using fuel sampling and analysis. This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **A.11** and **A.13**.
[Rule 62-296.405(1)(f)1.b., F.A.C.]

A.13. Sulfur Dioxide - Fuel Sampling. The following fuel sampling and analysis program shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using appropriate ASTM methods such as, ASTM D2013-72, ASTM D3177-75, and ASTM D4239-85, or latest ASTM edition methods, to analyze a representative sample of coal following each fuel delivery.

b. Record daily the amount of coal fired, the density of each fuel, the Btu value, and the percent sulfur content by weight of each fuel.

c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

Monitoring of Operations

A.14. Annual Tests Required - PM and VE. Except as provided in specific conditions **I.6** and **I.7** of this permit, emission testing for particulate matter emissions and visible emissions shall be performed annually.
[Rules 62-4.070(3), 62-213.440, and 62-297.310(7), F.A.C.]

A.15. Excess Emissions - Report. Submit to the Southwest District Air Section a written report of emissions in excess of emission limiting standards as set forth in this permit, for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

Oily Flyash

A.16. Oily Flyash. These emissions units may burn oily flyash ("flyash") from Bartow Unit 1 in accordance with the following:

a. Only flyash from Bartow Unit 1 may be burned in these emissions units. Once the accumulated backlog of Bartow Unit 1 flyash (estimated at approximately 13,000 tons) is burned, only the additional flyash generated at Bartow Unit 1 shall be burned in these emissions units.
b. The maximum flyash blend rate shall not exceed 2% of the total boiler feed on a weight basis.
c. The owner or operator shall make and maintain the following records for each day that flyash is burned in the boiler:

1. Date and Unit number;
2. Time period of flyash burning and start and end times;
3. Total quantity of flyash burned in tons per day;
4. Maximum flyash blend rate during period of flyash burn (percent flyash in total emissions unit fuel feed on a weight basis).

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 0170004-005-AO]

Common Conditions

A.17. These emissions units are also subject to conditions **I.1** through **I.15** contained in **Subsection I. Common Conditions.**

A.18. These emissions units are also subject to condition **K.1** contained in **Subsection K. Used Oil Common Condition.**

Record Keeping and Reporting Requirements:

A.19. COMS for Periodic Monitoring:
a. Periodic monitoring for opacity shall be COMS, which are maintained and operated in conformance with 40 CFR Part 75.
b. Periodic monitoring for particulate matter shall be COMS. For any calendar quarter in which more than five percent of the COMS readings show 20% or greater opacity for Units 2, 4, and 5 and 30% or greater opacity for Unit 1 (excluding startup, shutdown, and malfunction periods), a steady-state particulate matter stack test shall be performed within the following calendar quarter. Due to the allowed opacity level of 60% for sootblowing and load changing periods for Units 1 and 2, periods of sootblowing and load changing shall also be excluded for those units. The stack test shall comply with all of the testing and reporting requirements contained in the preceding specific conditions and, where practicable, shall be performed while operating at conditions representative of those showing greater than 20% opacity (30% for Unit 1). Units are not required to be brought on-line solely for the purpose of performing this special test. If the unit does not operate in the following quarter, the special test may be postponed until the unit is brought back on-line. In such cases, the special test shall be performed within 30 days.
[Rule 62-213.440, F.A.C.]

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, a dry bottom wall-fired unit, rated at 760 MW, 6665 MMBtu/hr, capable of burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil, with number 2 fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel, with emissions exhausted through a 600 ft. stack.
003	Fossil Fuel Steam Generator, Unit 5, a dry bottom wall-fired unit, rated at 760 MW, 6665 MMBtu/hr, capable of burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil, with number 2 fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel, with emissions exhausted through a 600 ft. stack.

Fossil Fuel Steam Generators, Units 4 and 5, are pulverized coal dry bottom boilers, wall-fired. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Combustion Engineering.

{Permitting Notes: These emissions units are regulated under Acid Rain, Phase I and II and Rule 62-210.300, F.A.C., Permits Required; 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; and, Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 4 began commercial operation in 1982. Fossil fuel fired steam generator Unit 5 began commercial operation in 1984.}

The following specific conditions apply to the emissions unit(s) listed above:

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
004	6665	Bituminous Coal and Bituminous Coal /Bituminous Coal Briquette Mixture
003	6665	Bituminous Coal and Bituminous Coal /Bituminous Coal Briquette Mixture

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **I.11.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Fuels. The only fuel allowed to be burned is bituminous coal or bituminous coal and bituminous coal briquette mixture with the exception that number 2 fuel oil may be used as an ignitor fuel, and natural gas may be used as a startup and low-load flame stabilization fuel. Fuel oil shall not contain more than 0.73% sulfur by weight. These emissions units may also burn used oil in accordance with other conditions of this permit (see **Subsection K**).
[Rule 62-213.410, F.A.C.; and, PPSC PA 77-09 and modified conditions]

Emission Limitations and Standards

B.4. Pursuant to 40 CFR 60.42 Standard For Particulate Matter.

(a) No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel.
(2) Exhibit greater than 20 percent opacity, six minute average, except for one six-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42(a)(1) & (2)]

B.5.a. Standard For Sulfur Dioxide.

(a) No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu), 24-hour average, derived from liquid fossil fuel.
(2) 520 nanograms per joule heat input (1.2 lb per million Btu), 24-hour average, derived from solid fossil fuel.
(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO2} = [y(340) + z(520)]/(y+z)$$

where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel.
(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
[40 CFR 60.43(a), (b) and (c); and, PPSC PA 77-09]

B.5.b. Standard For Sulfur Dioxide. The maximum sulfur dioxide emissions from the coal/briquette mixture shipment, averaged on an annual basis, shall not exceed the following: {See specific conditions **B.10.** and **B.11.**}

Emissions Unit No.	Emissions Unit Description	Average Sulfur Dioxide Limit, in Pounds Per Million Btu, Heat Input
004	FFSG, Unit 4	1.09
003	FFSG, Unit 5	1.09

[Rule 62-213.440, F.A.C.; and, 0170004-006-AC]

{Permitting note: The sulfur dioxide limit of the coal and coal briquette mixture is based on an annual average sulfur content of 0.68%, by weight, and an average heat content of 25.17 million Btu per ton of coal.}

B.6. Pursuant to 40 CFR 60.44 Standard For Nitrogen Oxides.
(a) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
(1) 86 nanograms per joule heat input (0.20 lb per million Btu), 30-day rolling average, derived from gaseous fossil fuel.
(2) 129 nanograms per joule heat input (0.30 lb per million Btu), 30-day rolling average, derived from liquid fossil fuel.
(3) 300 nanograms per joule heat input (0.70 lb per million Btu), 30-day rolling average, derived from solid fossil fuel.
(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{x(86)+y(130)+z(300)}{x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels fired;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel.
[40 CFR 60.44(a)(2) and (3), and (b); and, PPSC PA 77-09]

Test Methods and Procedures

B.8. Pursuant to 40 CFR 60.46 Test methods and Procedures.

(a) When conducting emissions tests, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).
(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$$E = C\,F_d\,(20.9)/(20.9 - \%O_2)$$

E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
% O_2 = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particulate matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_x concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_x sample.

(iii) The NO_x emission rate shall be computed for each pair of NO_x and O_2 samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels are fired, the owner or operator (in order to compute the prorated standard as shown in 40 CFR 60.43(b) and 60.44(b)) shall determine the percentage (x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D 2015-77 (solid fuels), D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the gross calorific values of the fuels.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_x may be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = C\ F_c\ (100\ /\ \%CO_2)$$

where:
E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
$\%CO_2$ = carbon dioxide concentration, percent dry basis.
F_c = factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b) (2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209 (F_{da} / F_{ca})$, then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference ($\overline{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if Fo is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when $\overline{d}$ is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used:

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in 40 CFR 60.46(d)(1).

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[40 CFR 60.46(a), (b), (c) & (d)]

B.9. Annual RATA Tests May Substitute for Annual NOx and SO_2 Tests. Annual RATA tests performed for nitrogen oxides and sulfur dioxide may be substituted for the annual compliance tests for these pollutants. To substitute for the annual compliance tests, the owner or operator must notify the Department of the RATA tests and the results must be submitted as the compliance tests, in accordance with the requirements of specific conditions I.6.(a)9. and I.15 of this permit. The requirements of specific conditions I.9 and I.12.(a)1. shall not apply to these tests. The test runs shall be consecutively completed in a manner that fulfills the test length requirements of the EPA test methods.
[Request of applicant, February 11, 1998]

B.10. The permittee shall demonstrate compliance with the sulfur dioxide limit in specific condition **B.5.b.** by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. See specific condition **B.5.b.** and **B.11.**
[Rule 62-213.440, F.A.C.; and, 0170004-006-AC]

B.11. Sulfur Dioxide - Fuel Sampling. The following fuel sampling and analysis program shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the fuel sulfur standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using appropriate ASTM methods such as, ASTM D2013-72, ASTM D3177-75, and ASTM D4239-85, or latest ASTM edition methods, to analyze a representative sample of coal following each fuel delivery.

b. Record daily the amount of coal fired, the density of each fuel, the Btu value, and the percent sulfur content by weight of each fuel.

c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rule 62-213.440, F.A.C.; and, 0170004-006-AC]

Monitoring of Operations

B.12. Maintain Daily Log. The owner or operator shall maintain a daily log of the amounts and types of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values to facilitate calculations of emissions.
[PPSC PA 77-09]

B.13. Annual Tests Required - PM, VE, SO_2 and NOx. Except as provided in specific conditions **I.6** and **I.7** of this permit, emission testing for particulate matter emissions, visible emissions, sulfur dioxide and nitrogen oxides shall be performed annually.
[Rules 62-4.070(3), 62-213.440, and 62-297.310(7), F.A.C.]

B.14. Pursuant to 40 CFR 60.45 Emission Monitoring.

CMS for Opacity, SO_2, NOx, and CO_2 are Required.
(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and carbon dioxide except as provided in 40 CFR 60.45(b).
(c) For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas................................	{1}	500
Liquid............................	1,000	500
Solid..............................	1,500	1000
Combinations.................	1,000y+1,500z	500(x+y)+1,000z

{1}Not applicable.

where:
x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.
(e) For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E = CF[20.9/(20.9\text{-percent } O_2)]$
where:
E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$E = CF_c\ [100/\text{percent } CO_2]$
where:
E, C, F_c and %CO_2 are determined under 40 CFR 60.45(f).
(f) The values used in the equations under 40 CFR 60.45(e) (1) and (2) are derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:
(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), $F = 2.637 \times 10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c = 0.486 \times 10^{-7}$ scm CO_2 /J (1,810 scf CO_2 /million Btu).
(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).

(iv) For gaseous fossil fuels, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2 /J (1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /million Btu) for butane.

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

$$F = 10^{-6}\frac{[227.2\ (\text{pct. H}) + 95.5\ (\text{pct. C}) + 35.6\ (\text{pct. S}) + 8.7\ (\text{pct. N}) - 28.7\ (\text{pct. O})]}{\text{GCV}}$$

$$F_c = \frac{2.0\text{x}10^{-5}\ (\text{pct. C})}{\text{GCV}}$$

(SI units)

$$F = 10^{6}\ \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{\text{GCV}}$$

(English units)

$$F_c = \frac{20.0(\%C)}{\text{GCV}}$$

(SI units)

$$F_c = \frac{321\text{x}10^{3}\ (\%C)}{\text{GCV}}$$

(English units)

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-74 or D3176 (solid fuels) or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)

(6) For affected facilities firing combinations of fossil fuels, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:
X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, etc.)
F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.
n = the number of fuels being burned in combination.
[40 CFR 60.45(a), (b), (c), (e) and (f); PPSC PA 77-09]

B.15. Excess Emission Reports.
(g) Excess emission reports shall be submitted to the Department for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission report shall include the information required in 40 CFR 60.7(c). Periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.
[40 CFR 60.45(g)]

Other NSPS Subpart D Conditions

B.16. Pursuant to 40 CFR 60.41 Definitions. As used in 40 CFR 60 Subpart D, all terms not defined in 40 CFR 60.41 shall have the meaning given them in the Act, and in Subpart A of 40 CFR 60.

Ambient Air Monitoring

B.17. Ambient Air Monitoring. The owner or operator shall continue to operate the existing ambient monitoring devices for sulfur dioxide and suspended particulate at the two existing locations (sites) designated on Figure A, Ambient Air Monitoring Locations, Crystal River, Florida, attached to this permit. The frequency of operation of each monitoring device for suspended particulate shall be every six days, and continuously for sulfur dioxide, unless otherwise specified by the Department. New or existing monitoring devices shall be located as designated by the Department. The monitoring devices for sulfur dioxide shall meet the requirements of 40 CFR 53.
[PPSC PA 77-09, and order modifying conditions of certification, OGC Case No. 83-0818, dated February 2, 1984, and Rules 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

B.18. Flue Gas Desulfurization (FGD) equipment. Prior to the installation of any FGD equipment, plans and specifications for such equipment shall be submitted to the Department for review and approval.
[PPSC PA 77-09]

Common Conditions

B.19. These emissions units are also subject to conditions **I.1** through **I.15**, except for **I.2** and **I.3**, contained in **Subsection I. Common Conditions.**

B.20. These emissions units are also subject to conditions **J.1** through **J.5** contained in **Subsection J. NSPS Common Conditions.**

B.21. These emissions units are also subject to condition **K.1** contained in **Subsection K. Used Oil Common Condition.**

Subsection C. This section addresses the following emissions units.

E.U. ID No.	Brief Description
006	Fly ash transfer (Source 1) from Fossil Fuel Steam Generator (FFSG) Unit 1.
008	Fly ash storage silo (Source 3) for FFSG Units 1 and 2.
009	Fly ash transfer (Source 4) from FFSG Unit 2.
010	Fly ash transfer (Source 5) from FFSG Unit 2.

Emissions unit 006 is a fly ash transfer (Source 1) from Fossil Fuel Steam Generator (FFSG) Unit 1. This emissions unit consists of the fly ash conveying line, dense phase transfer vessel and separator used to transfer fly ash from the FFSG Unit 1 electrostatic precipitator to the fly ash storage silo (Source 3) at a design transfer rate of 44 tons per hour. Particulate matter emissions are controlled by a Monex Resources, Inc. Model MD80 baghouse at a design air flow of 1820 acfm.

Emissions unit 008 is a fly ash storage silo (Source 3) for FFSG Units 1 and 2. This emissions unit consists of the fly ash storage silo used to store fly ash from the electrostatic precipitators of FFSG Units 1 and 2. Fly ash is pneumatically conveyed from the FFSG Units 1 and 2 ESPs at a combined transfer rate of 174 tons per hour. Particulate matter emissions are controlled by a PulseKing Model M 100 S baghouse at a design air flow of 2546 acfm. Fly ash from the storage silo is disposed of either in a dry form by loading into enclosed tanker trucks or in a wet form by loading wet ash into open trucks.

Emissions unit 009 is a fly ash transfer (Source 4) from FFSG Unit 2. This emissions unit consists of the fly ash conveying line, dense phase transfer vessel and separator used to transfer fly ash from the FFSG Unit 2 ESP number 2C to the fly ash storage silo (Source 3) at a design transfer rate of 60 tons per hour. Particulate matter emissions are controlled by a Monex Resources, Inc. Model MD80 baghouse at a design air flow of 2200 acfm.

Emissions unit 010 is a fly ash transfer (Source 5) from FFSG Unit 2. This emissions unit consists of the fly ash conveying line, dense phase transfer vessel and separator used to transfer fly ash from the FFSG Unit 2 ESP number 2A and 2B to the fly ash storage silo (Source 3) at a maximum design transfer rate of 70 tons per hour. Particulate matter emissions are controlled by a Monex Resources, Inc. Model MD80 baghouse at a design air flow of 2800 acfm.

{Permitting note(s): These emissions units are regulated under Best Available Control Technology (BACT) Determinations ordered 2/5/79 (proposed 1/26/79) and 8/16/79.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The transfer rates shall not exceed:

Emissions Unit	Transfer Rate (tons per hour)
006	44
008	174
009	60
010	70

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

C.2. Emission Limitations. Emissions of particulate matter from the following emissions units shall not exceed:

Emissions Unit	Emission Limit (pounds per hour)	Emission Limit (tons per year)
006	3.5 [a]	15.4 [a]
008	0.6 [a]	2.6 [a]
009	2.2 [b]	9.6 [b, c]
010	2.2 [b]	9.6 [b, c]

Notes:

a Emission limits based on a BACT Determination proposed 1/26/79, ordered 2/5/79. BACT for emissions units 006 and 007 included a VE limit of 5% opacity, six minute average.

b Emission limits based on a BACT Determination ordered 8/16/79.

c The tons per year limits for emissions units 009 and 010 have been corrected to one decimal place.

[AC 09-257911]

C.3. VE in Lieu of Stack Test. Because the ash handling system emissions units are controlled with baghouses, the Department has waived particulate matter testing requirements and specified an alternate standard of 5% opacity. If the Department has reason to believe that the particulate emission standard applicable to each emissions unit (006, 008, 009 and 010) is not being met, it may require that compliance be demonstrated by stack testing in accordance with Chapter 62-297, F.A.C.
[Rule 62-297.620(4), F.A.C.; and, AC 09-256791]

C.4. Additional Reasonable Precautions for Control of Particulate Matter Emissions. The owner or operator shall take the following reasonable precautions to control emissions of particulate matter from transport of ash from emissions unit 008 for disposal or use. Ash for transport shall be wetted before loading into open trucks, or dry ash shall be transferred to enclosed tanker trucks.
[Rule 62-4.070(3), F.A.C.; and, AC 09-256791]

Monitoring of Operations

C.5. Annual VE Tests Required. Each emissions unit (006, 008, 009 and 010) shall be tested for visible emissions annually using EPA Method 9. Each test shall be a minimum of thirty minutes in duration from each exhaust point, while transferring fly ash from both FFSG Units 1 and 2 to the silo (emissions unit 008) at the same time. The tests shall be conducted during a period when both FFSG Units 1 and 2 are operating at 90 to 100% of full load while sootblowing. A statement of the FFSG unit loads, verifying the tests were conducted during sootblowing, shall be submitted with the test reports.
[Rule 62-4.070(3), F.A.C.; and, AC 09-256791]

{Permitting note: For those emissions points containing a baghouse, the permittee shall perform and record the results of weekly qualitative observations of visible emissions checks (e.g., Method 22) with follow-up Method 9 tests within 24 hours of any abnormal visible emissions.}

Common Conditions

C.6. These emissions units are also subject to conditions **I.1** through **I.15**, except for **I.3**, contained in **Subsection I. Common Conditions.**

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
014	Bottom ash storage silo for FFSG Units 1 and 2, with associated vacuum blower exhausts and bin vent filter (total of three emission points).

Emissions unit 014 is a bottom ash storage silo for FFSG Units 1 and 2, with associated vacuum blower exhausts and bin vent filter (total of three emission points). This emissions unit consists of the system to collect and store bottom ash and economizer ash from both FFSG Units 1 and 2 at a total rate of 16 tons per hour (8 tons per hour from each FFSG unit) at an airflow rate of 2200 scfm from each unit. Ash is conveyed by vacuum from each FFSG unit by a separate vacuum blower, with air and ash passing through a baghouse (filter/separator) where ash is deposited in the silo and air is exhausted through the vacuum blower. Air displaced in the silo is vented through an additional bag filter (the bin vent filter) at an airflow rate of 2400 scfm. Ash stored in the silo is unloaded into trucks for sale, use or disposal at the on-site ash disposal facility. Ash will be wet via a pugmill before loading into open trucks, or dry ash will be transferred to enclosed tanker trucks.

{Permitting note(s): This emissions unit is regulated under Rule 62-296.320, F.A.C., and by applicable requirements of AC 09-235915.}

The following specific conditions apply to the emissions unit(s) listed above:

<u>Essential Potential to Emit (PTE) Parameters</u>

D.1. <u>Permitted Capacity</u>. The transfer rates shall not exceed 16 tons per hour (8 tons per hour from each FFSG unit).
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

<u>Emission Limitations and Standards</u>

D.2. <u>Visible Emissions (VE) Limitation</u>. Visible emissions shall be less than 20% opacity, six minute average, established by Rule 62-296.320(4)(b)1, F.A.C. See Section II, condition **3** of this permit.
[Rule 62-296.320(4)(b)1, F.A.C.]

D.3. <u>Additional Reasonable Precautions for Control of Particulate Matter Emissions</u>. The owner or operator shall take the following reasonable precautions to control emissions of particulate matter from transport of ash from emissions unit 014 for disposal or use. Ash for transport shall be wet via a pugmill before loading into open trucks, or dry ash shall be transferred to enclosed tanker trucks.
[Rule 62-4.070(3), F.A.C.; and, AC 09-235915]

Monitoring of Operations

D.4. Annual VE Tests Required. Each emission point of emissions unit 014 shall be tested for visible emissions annually using EPA Method 9. Each test shall be a minimum of thirty minutes in duration from each exhaust point, while transferring bottom ash and economizer ash from both FFSG Units 1 and 2 to the silo at the same time at 90-100% of design throughput rate of 8 TPH.
[Rules 62-4.070(3) and 62-296.320(4)(b)4, F.A.C.; AC 09-235915; and, AO 09-248541]

{Permitting note: For those emissions points containing a baghouse, the permittee shall perform and record the results of weekly qualitative observations of visible emissions checks (e.g., Method 22) with follow-up Method 9 tests within 24 hours of any abnormal visible emissions.}

Common Conditions

D.5. This emissions unit is also subject to conditions **I.1** through **I.15**, except for **I.3**, contained in **Subsection I. Common Conditions.**

Subsection E. This section addresses the following emissions unit.

Facility ID No.	E. U. ID No.	Brief Description
7775047	-001	Relocatable diesel generator(s) will have a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts. Emissions from the generator(s) are uncontrolled.

The generators may be relocated to any of the following facilities:

1. Crystal River Plant, Powerline Road, Red Level, Citrus County.
2. Bartow Plant, Weedon Island, St. Petersburg, Pinellas County.
3. Higgins Plant, Shore Drive, Oldsmar, Pinellas County.
4. Bayboro Plant, 13th Ave. & 2nd St. South, St. Petersburg, Pinellas County.
5. Wildwood Reclamation Facility, State Road 462, 1 mi. east of U.S. 301, Wildwood, Sumter County.
6. Hines Energy Complex, County Road 555, 1 mi. southwest of Homeland, Polk County.
7. Anclote Power Plant, 1729 Baileys Road, Holiday, Pasco County

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. Each generator has its own stack. This section of the permit is only applicable when the generator(s) is(are) located at the Crystal River Plant.}

The following specific conditions apply to the emissions units listed above regardless of location:

<u>Essential Potential to Emit (PTE) Parameters</u>

E.1. Permitted Capacity. The maximum (combined) heat input rate shall not exceed 25.74 million Btu per hour.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

E.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **E.9.**
[Rule 62-297.310(2), F.A.C.]

E.3. Methods of Operation - Fuels. Only new No. 2 fuel oil with a maximum sulfur content of 0.5%, by weight, shall be fired in the diesel generator(s).
[Rule 62-213.410, F.A.C.; and, AC 09-202080.]

E.4. Hours of Operation. The hours of operation expressed as "engine-hours" shall not exceed 2970 hours in any consecutive 12 month period. The total hours of operation expressed as "engine-hours" shall be the summation of the individual hours of operation of each generator.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC 09-202080.]

<u>Emission Limitations and Standards</u>

E.5. Visible Emissions. Visible emissions from each generator shall not be equal to or greater than 20 percent opacity, six minute average.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC 09-202080.]

Monitoring of Operations

E.6. Fuel Sulfur Analysis. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or permittee upon each fuel delivery. See specific condition **E.3.** and **E.8.**
[Rule 62-213.440, F.A.C.]

Test Methods and Procedures

E.7. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

E.8. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-94, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s).
[Rules 62-213.440 and 62-297.440, F.A.C.]

E.9. Operating Rate During Testing. Testing of emissions shall be conducted with the generator(s) operating at 90 to 100 percent of the maximum fuel firing rate for each generator. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operations may be limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Failure to submit the actual operating rate may invalidate the test.
[Rule 62-297.310(2), F.A.C.; and, AC 09-202080]

E.10. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning liquid fuels for less than 400 hours per year.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

E.11. After each relocation, each generator shall be tested within 30 days of startup for opacity and the fuel shall be analyzed for the sulfur content. See specific conditions **E.3.**, **E.5.**, and **E.6.**
[Rules 62-4.070(3) and 62-297.310(7)(b),F.A.C.; and, AO 09-205952.]

Record Keeping and Reporting Requirements

E.12. To demonstrate compliance with specific condition **E.4.**, records shall indicate the daily hours of operation for each of the generators, the daily hours of operation expressed as "engine- hours" and the cumulative total hours of operation expressed as "engine-hours" for each month. The records shall be maintained for a minimum of 5 years and made available to the Southwest District Office upon request.
[Rules 62-213.440 and 62-297.310(8), F.A.C.; and, AO 09-205952.]

E.13. To demonstrate compliance with specific condition **E.3.**, records of the sulfur content, in percent by weight, of all the fuel burned shall be kept based on either vendor provided as-delivered or as-received fuel sample analysis. The records shall be maintained for a minimum of 5 years and made available to the Southwest District Office upon request.
[Rule 62-297.310(8), F.A.C.; and, AC 09-202080.]

<u>**Source Obligation**</u>

E.14. Specific conditions in construction permit AC 09-202080, limiting the "engine hours", were accepted by the applicant to escape Prevention of Significant Deterioration review. If Florida Power Corporation requests a relaxation of any of the federally enforceable emission limits in this permit, the relaxation of limits may be subject to the preconstruction review requirements of Rule 62-212.400(5), F.A.C., as though construction had not yet begun.
[Rule 62-212.400(2)(g), F.A.C.; and, AC 09-202080.]

E.15. Florida Power Corporation shall notify the Department's Southwest District Office, in writing, at least 15 days prior to the date on which any diesel generator is to be relocated. The notification shall specify the following;

a. which generator, by serial number, is being relocated,
b. which location the generator is being relocated from and which location it is being relocated to, and
c. the approximate startup date at the new location.

If a diesel generator is to be relocated within Pinellas County, then Florida Power Corporation shall provide the same notification to the Air Quality Division of the Pinellas County Department of Environmental Management.
[Rule 62-4.070(3), F.A.C.; and, AC 09-202080]

<u>**Common Conditions**</u>

E.16. This emissions unit is also subject to conditions **I.1** through **I.15**, except for **I.3** and **I.8**, contained in **Subsection I. Common Conditions.**

Subsection F. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
013	Cooling towers for FFSG Units 1, 2 and nuclear Unit 3, used to reduce plant discharge water temperature.

Emissions unit 013 is cooling towers for FFSG Units 1, 2 and nuclear Unit 3, used to reduce plant discharge water temperature. (This emission unit may be referred to as "helper cooling towers.") This emissions unit consists of four towers with nine cells per tower, with high efficiency drift eliminators, operating at a maximum seawater flow rate of 735,000 gallons per minute for all cells combined, with a design airflow rate of 1.46×10^6 acfm from each cell. Seawater is sprayed through the towers where fan induced air flow causes evaporative cooling. Water vapor, saltwater droplets (drift) and salt particles are emitted. Drift emissions are controlled by high efficiency drift eliminators.

{Permitting note(s): This emissions unit is regulated under Prevention of Significant Deterioration (PSD) (PSD permit AC 09-162037/PSD-FL-139 issued 8/29/90) and Best Available Control Technology (BACT), Determination dated 8/29/90, which set a drift emission rate of 0.004%.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Permitted Capacity. The seawater flow rate shall not exceed 735,000 gallons per minute for all cells combined.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The seawater flow rate limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load) and to aid in determining future rule applicability. Regular record keeping is not required for seawater flow rates. Instead the owner or operator is expected to determine the seawater flow rate whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such seawater flow rate determination may be based on measurements of flow by various methods including but not limited to flow metering or the use of pump curves supplied by the manufacturer to calculate an average hourly seawater flow rate during the test.}

F.2. Hours of Operation. The operating hours for each cooling tower pump shall not exceed 4320 hours per year (12-month rolling total).
[Rule 62-210.200(PTE), F.A.C.; and, AC 09-162037 (PSD-FL-139)]

Emission Limitations and Standards

F.3. Cooling Tower Emission Limit. Emissions of particulate matter from each cooling tower cell shall not exceed 11.9 pounds per hour.
{Note: The emission limit is based on a BACT Determination setting the maximum drift emissions at 0.004%. Equivalent maximum emissions are 428 lb/hr and 925 tons per year total for all cells. PM_{10} emissions are estimated to be approximately 50% of the particulate matter emission rate.}
[Rule 62-213.440, F.A.C.; and, AC 09-162037 (PSD-FL-139)]

F.4. Drift Eliminators. Drift eliminators shall be installed and maintained so that minimum bypass occurs. Regular maintenance shall be scheduled to ensure proper operation of the drift eliminators.
[Rule 62-213.440, F.A.C.; and, AC 09-162037 (PSD-FL-139)]

{Note: This emissions unit is not subject to a visible emissions limitation. Emissions from this emissions unit include water droplets so visible emissions testing is not possible.}

Test Methods and Procedures

F.5. Emission Test Method. Test using EPA Method 5, from 40 CFR 60 Appendix A, except that a distilled water rinse shall be used in place of acetone, and the impinger catch shall be excluded from the emission calculations. Testing shall be conducted on one cell, selected by the Department, of each of the four towers while the towers are being operated at 90-100% of the seawater flow rate. The seawater flow rate shall be estimated using manufacturers certified pump curves or other method approved by the Department. The test report shall include the estimated seawater and air flow rates.
[Rule 62-213.440, F.A.C.; and, AC 09-162037 (PSD-FL-139)]

Monitoring of Operations

F.6. Test Every Five Years. The owner or operator shall test for particulate emissions every five years, unless actual emissions exceed 80% of allowable, in which case compliance testing is required every 30 months until actual emissions are less than 80% of allowable.
[Rule 62-213.440 and 62-297.310(7), F.A.C.; AC 09-162037 (PSD-FL-139); and, AO 09-236827]

Record Keeping and Reporting Requirements

F.7. Pump Run Time Meters Required. Equip each cooling tower seawater pump with a run-hour meter and maintain records of run time for each pump based on run-hour meters for each calendar month.
[Rule 62-213.440, F.A.C.; and, AC 09-162037 (PSD-FL-139)]

Common Conditions

F.8. This emissions unit is also subject to conditions **I.1** through **I.15**, except for **I.3**, **I.7** and **I.8**, contained in **Subsection I. Common Conditions.**

Subsection G. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
015	Cooling towers for FFSG Units 4 and 5 used to reduce plant discharge water temperature.

Emissions unit 015 is cooling towers for FFSG Units 4 and 5 used to reduce plant discharge water temperature. (These towers are hyperbolic cooling towers.) Seawater is sprayed through the towers where induced air flow causes evaporative cooling. Water vapor, saltwater droplets (drift) and salt particles are emitted. Drift emissions controlled by high efficiency drift eliminators. Seawater flow rate is 331,000 gallons per minute.

{Permitting note(s): This emissions unit is regulated under Prevention of Significant Deterioration (PSD) (PSD permit PSD-FL-007 issued by EPA as modified by EPA on 11/30/88.)}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

G.1. Permitted Capacity. The maximum seawater flow rate shall not exceed 331,000 gallons per minute per cooling tower.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The seawater flow rate limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load) and to aid in determining future rule applicability. Regular record keeping is not required for seawater flow rates. Instead the owner or operator is expected to determine the seawater flow rate whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such seawater flow rate determination may be based on measurements of flow by various methods including but not limited to flow metering or the use of pump curves supplied by the manufacturer to calculate an average hourly seawater flow rate during the test.}

Emission Limitations and Standards

G.2. Cooling Tower Emission Limit. Emissions of particulate matter shall not exceed 175 lb/hr from each cooling tower.
{Note: The emission limit is based on a BACT Determination requiring control of drift emissions with drift eliminators. The modified PSD permit removed a limitation on drift rate, substituting an emissions limit in pounds per hour. PM emissions are assumed to be all PM_{10}.}
[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

{Note: This emissions unit is not subject to a visible emissions limitation. Emissions from this emissions unit include water droplets so visible emissions testing is not possible.}

Test Methods and Procedures

G.3. Emission Test Method. Testing shall be in accordance with following requirements:

a. Particulate matter emissions shall be measured by the sensitive paper method.
b. Testing shall be conducted either at the drift eliminator level within the tower or at the tower exit plane. (The sampling locations at the drift eliminator level and apparatus are shown in diagrams attached as Appendix P.)
c. No less than three test runs shall be conducted for each test and all valid data from each of these test runs shall be averaged to demonstrate compliance. No individual test run result shall determine compliance or noncompliance. The emission rate reported as a percent of the circulating water, as well as lb/hr., and total dissolved solids in the cooling tower basin and intake water, shall be reported for each test run.

[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

Monitoring of Operations

G.4. Test Every Five Years. The FFSG Unit 4 cooling tower shall be tested every five years from 1988 (the next required year from the effective date of this permit is 2003). The FFSG Unit 5 cooling tower shall be tested every five years from 1992 (the next required year from the effective date of this permit is 2002).
[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88, request of applicant]

G.5. Inspection. The drift eliminators of both towers shall be inspected from the concrete walkways not less than every three months by Florida Power Corporation staff or representatives to assure that the drift eliminators are clean and in good working order. Not less than annually, a complete inspection of the towers shall be conducted by a manufacturer of drift eliminators or by a consultant with recognized expertise in the field.
Certification that the drift eliminators are properly installed and in good working order shall be made at the time of submission of the reports noted below.
[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

Record Keeping and Reporting Requirements

G.6. Reporting. Reports on tower testing and inspection shall be submitted as follows:

a. Within 30 days after all visual inspections of the drift eliminators.
b. Within 45 days after the compliance testing of either tower.

[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

G.7. Excess Emissions. Should either tower emission rate exceed 175 lb/hr, the permittee shall:

a. Notify EPA and the Department within 10 days of becoming aware of the exceedence.
b. Provide an assessment of necessary corrective actions and a proposed schedule of implementation within an additional 20 days.
c. Expeditiously complete corrective actions.
d. Retest the tower within three months after the correction is completed.
e. Submit the testing report within 45 days after completion of said tests.

[Rule 62-213.440, F.A.C.; and, Modified PSD permit, PSD-FL-007, issued by EPA 11/30/88]

Common Conditions

G.8. This emissions unit is also subject to conditions **I.1** through **I.15**, except for **I.3**, **I.7** and **I.8**, contained in **Subsection I. Common Conditions.**

Subsection H. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
016	Material handling activities for coal-fired steam units.

Emissions unit 016 is material handling activities for coal-fired steam units. This emissions unit consists of the storage and transport of coal, fly ash and bottom ash for FFSG Units 1, 2, 4 and 5 and not addressed by other emissions units. Emissions are particulate matter and PM_{10} from these activities.

{Permitting note(s): This emissions unit is regulated partially under Power Plant Siting Certification PA 77-09; NSPS 40 CFR 60 Subpart Y (Units 4 and 5 only); and PSD permit AC 09-162037, PSD-FL-139.}

The following specific conditions apply to the emissions unit(s) listed above:

<u>**Emission Limitations and Standards**</u>

H.1. <u>Pursuant to 40 CFR 60.252 Standards for Particulate Matter</u>.
(c) The owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.
[40 CFR 60.252 (coal facilities associated with Units 4 and 5)]

H.2. <u>Visible Emissions</u>. The owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater, six minute average.
[PPSC PA 77-09 (coal facilities associated with Units 1, 2, 4 and 5)]

H.3. <u>PM Control -- BMPs</u>. The owner or operator shall control particulate emissions (PM and PM_{10}) through the practices described in the Best Management Plan authored by KBN, November 1990, and distributed to FPC staff November 21, 1990, by Mr. W. Jeffrey Pardue.
[AC 09-162037, PSD-FL-139 (for construction of helper cooling towers) specific condition 3]

<u>**Test Methods and Procedures**</u>

H.4. <u>Visible Emissions</u>. **(This condition applies to coal facilities associated with emissions units 004 and 003 -- FFSG Units 4 and 5.)** <u>Pursuant to 40 CFR 60.254 Test Methods and Procedures</u>.
(2) EPA Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.
[40 CFR 60.254]

H.5. <u>Visible Emissions</u>. **(This condition applies to coal facilities associated with emissions units 001 and 002 -- FFSG Units 1 and 2.)** <u>VE Test Method</u>. EPA Method 9 shall be used to determine opacity.
[Rules 62-4.070(3), 62-213.440 and 62-297.401, F.A.C.]

{Permitting note: For those emissions points containing a baghouse, the permittee shall perform and record the results of weekly qualitative observations of visible emissions checks (e.g., Method 22) with follow-up Method 9 tests within 24 hours of any abnormal visible emissions.}

Common Conditions

H.6. This emissions unit is also subject to conditions **I.1**, **I.2**, **I.4**, **I.5**, and **I.14** (condition **I.2** is also not applicable to activities at units subject to NSPS 40 CFR 60 (i.e., activities at FFSG Units 4 and 5) contained in **Subsection I. Common Conditions.** This emissions unit is also subject to conditions **I.6.(a)9** & **(b)**, **I.12(a)2** and **I.15.(a)** & **(b)**; the other provisions of conditions **I.6**, **I.12** and **I.15** are not applicable to this emissions unit.

H.7. These emissions units are also subject to conditions **J.1**, **J.2**, **J.3(b), (c) and (d)** and **J.4** contained in **Subsection J. NSPS Common Conditions.**

Subsection I. Common Conditions.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator (FFSG), Unit 1
002	FFSG, Unit 2
004	FFSG, Unit 4
003	FFSG, Unit 5
006	Fly ash transfer (Source 1) from FFSG Unit 1
008	Fly ash storage silo (Source 3) for FFSG Units 1 and 2
009	Fly ash transfer (Source 4) from FFSG Unit 2
010	Fly ash transfer (Source 5) from FFSG Unit 2
014	Bottom ash storage silo for FFSG Units 1 and 2, with associated vacuum blower exhausts and bin vent filter (total of three emission points)
7775047, 001	Three relocatable diesel fired generators, rated at 0.82 MW, 8.58 MMBtu/hr
013	Cooling towers for FFSG Units 1, 2, and 3, used to reduce plant discharge water temperature
015	Cooling towers for FFSG Units 4 and 5 used to reduce plant discharge water temperature
016	Material handling activities for coal-fired steam units

Except as otherwise specified under Subsections A. through H., the following conditions apply to the emissions units listed above:

<u>Essential Potential to Emit (PTE) Parameters</u>

I.1. <u>Hours of Operation.</u> The emissions units may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

<u>Emission Limitations and Standards</u>

{Permitting Notes: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

<u>Excess Emissions</u>

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.}

I.2. (This condition is not applicable to emissions units 004 and 003 - FFSG Units 4 and 5.) Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

I.3. (This condition applies to emissions units 001 and 002 - FFSG Units 1 and 2.) Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

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

Monitoring of Operations

I.5. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

I.6. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; or 100 tons per year or more of any other regulated air pollutant; and
    c. Any NESHAP pollutant.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; SIP approved]

I.7. When PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Test Methods and Procedures

{Permitting Notes: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

I.8. (This conditions applies to emissions units 001, 002, 003, 004, 006, 008, 009, 010, & 014.) Visible Emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800 and 62-297.401, F.A.C.]

I.9. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

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

I.11. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15

consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

I.12. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

I.13. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Record Keeping and Reporting Requirements

I.14. Malfunctions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Southwest District Air Section in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Southwest District Air Section.
[Rule 62-210.700(6), F.A.C.]

I.15. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Southwest District Air Section on the results of each such test.
(b) The required test report shall be filed with the Southwest District Air Section as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Southwest District Air Section to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Subsection J. NSPS Common Conditions.

E.U. ID No.	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, rated at 760 MW, 6665 MMBtu/hr, capable of burning bituminous coal, with number 2 fuel oil as a startup fuel, with emissions exhausted through a 600 ft. stack.
003	Fossil Fuel Steam Generator, Unit 5, rated at 760 MW, 6665 MMBtu/hr, capable of burning bituminous coal, with number 2 fuel oil as a startup fuel, with emissions exhausted through a 600 ft. stack.
016	Material handling activities for coal-fired steam units subject to NSPS (i.e., activities at Fossil Fuel Fired Steam Generators Units 4 and 5.

{Permitting Notes: The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected facilities to which this subpart applies are fossil fuel steam generators Unit 4 and Unit 5. To the extent allowed by law, the "Administrator" shall mean the "Department."}

The following conditions apply to the NSPS emissions units listed above:

J.1. Pursuant to 40 CFR 60.7 Notification And Record Keeping.

(a) Any owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(b) The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see 40 CFR 60.7(d)) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.
(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

[See Attached Figure 1-Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance]

(e)(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:
(i) For one full year (e.g., four quarterly or twelve monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under 40 CFR 60 continually demonstrate that the facility is in compliance with the applicable standard;
(ii) The owner or operator continues to comply with all record keeping and monitoring requirements specified in this subpart and the applicable standard; and
(iii) The Administrator does not object to reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.
(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required record keeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.
(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.
(f) The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by

40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

J.2. Pursuant to 40 CFR 60.8 Performance Tests.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.
(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8]

J.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.

(a) Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in 40 CFR 60.11 shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of 40 CFR 60.11, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
(c) The opacity standards set forth in 40 CFR 60.11 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(e)(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance

purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11]

J.4. Pursuant to 40 CFR 60.12 Circumvention.

No owner or operator subject to the provisions of 40 CFR 60.12 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

J.5. Pursuant to 40 CFR 60.13 Monitoring Requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)(1) Owners and operators of all continuous emission monitoring systems installed in accordance with the provisions of 40 CFR 60.13 shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or

other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorder during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[40 CFR 60.13]

Subsection K. Used Oil Common Condition.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
004	Fossil Fuel Steam Generator, Unit 4
003	Fossil Fuel Steam Generator, Unit 5

{Permitting Notes: The emissions units above are subject to the following condition which allows the burning of on-specification used oil pursuant to the requirements of this permit and this subsection.}

The following condition applies to the emissions units listed above:

K.1. Used Oil. Burning of on-specification used oil is allowed in emissions units 001, 002, 004 and 003 in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Allowed as Fuel: This permit allows the burning of used oil fuel meeting EPA "on-specification" used oil specifications, with a PCB concentration of less than 50 ppm. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility.

   On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]

   Arsenic shall not exceed 5.0 ppm;
   Cadmium shall not exceed 2.0 ppm;
   Chromium shall not exceed 10.0 ppm;
   Lead shall not exceed 100.0 ppm;
   Total halogens shall not exceed 1000 ppm;
   Flash point shall not be less than 100 degrees F.

b. Quantity Limited: The maximum quantity of on-specification used oil that may be burned in all four emissions units combined is 10 million gallons in any consecutive 12-month period.

c. Used Oil Containing PCBs Not Allowed: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

   Before accepting from each marketer the first shipment of on-specification used oil with a PCB concentration of 2 to 49 ppm, the owner or operator shall provide each marketer with a one-time written and signed notice certifying that the owner or operator will burn the used oil in a qualified combustion device and must identify the class of combustion device. The notice must state that EPA or a RCRA-delegated state agency has been given a description of the used oil management activities at the facility and that an industrial boiler or furnace will be used to burn the used oil with a PCB concentration of 2 to 49 ppm. The description of the used oil management activities shall be submitted to the EPA or may be submitted to the Administrator, Hazardous Waste Regulation Section, Florida Department of

Environmental Protection, 2600 Blair Stone Road, Tallahassee, FL 32399-2400. A copy of the notice provided to each marketer shall be maintained at the facility. [40 CFR 279.61 and 761.20(e)]

e. Certification Required: The owner or operator shall receive from the marketer, for each load of used oil received, a certification that the used oil meets the specifications for on-specification used oil and contains a PCB concentration of less than 50 ppm. This certification shall also describe the basis for the certification, such as analytical results.

   Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs. Note that a claim that used oil does not contain quantifiable levels of PCBs (that is, that the used oil contains less than 2 ppm of PCBs) must be documented by analysis or other information. The first person making the claim that the used oil does not contain PCBs is responsible for furnishing the documentation. The documentation can be tests, personal or special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the used oil contains no detectable PCBs.

f. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

   Arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs*, and specific gravity.

   Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.
   * Analysis for PCBs is not required if a claim is made that the used oil does not contain quantifiable levels of PCBs.

g. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)]

   (1) The gallons of on-specification used oil accepted and burned each month in each unit. (This record shall be completed no later than the fifteenth day of the succeeding month.)
   (2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period in each unit. (This record shall be completed no later than the fifteenth day of the succeeding month.)
   (3) Results of the analyses required above, including documentation if a claim is made that the used oil does not contain quantifiable levels of PCBs.
   (4) The source and quantity of each batch of used oil received each month, including the name, address and EPA identification number (if applicable) of all marketers that delivered used oil to the facility, and the quantity delivered.
   (5) Records of the operating rate of each unit while burning used oil and the dates and time periods each unit burns used oil.

h. Reporting Required: The owner or operator shall submit to the Department's Southwest District office, with the Annual Operation Report form, an attachment showing the total amount of on-specification used oil burned during the previous calendar year. The quantity of used oil shall be individually reported and shall not be combined with other fuels.

[Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, and 0170004-002-AO, unless otherwise noted]

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power Corporation/Crystal River Plant
ORIS code: 628

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions units listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
004	Fossil Fuel Steam Generator, Unit 4
003	Fossil Fuel Steam Generator, Unit 5

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. DEP Form No. 62-210.900(1)(a), dated July 1, 1995.
b. Phase II Acid Rain Application/Compliance Plan received 12/22/95

[Chapter 62-213, F.A.C., and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003	2004
001	1	**SO2 allowances, under Table 2 or 3 of 40 CFR Part 73**	12320*	12320*	12320*	12320*	12320*
		NOx limit	Pursuant to 40 CFR part 76, the Florida Department of Environmental Protection approves a NO_X standard emissions compliance plan for unit 1. The NO_X compliance plan is effective beginning 2000 through calendar year 2003. Under the NO_X compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(1) of 0.40 lb/MMBtu for tangentially fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.				

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003	2004
002	2	**SO2 allowances, under Table 2 or 3 of 40 CFR Part 73**	14173*	14173*	14173*	14173*	14173*
004	4	**SO2 allowances, under Table 2 or 3 of 40 CFR Part 73**	23452*	23452*	23452*	23452*	23452*
003	5	**SO2 allowances, under Table 2 or 3 of 40 CFR Part 73**	25040*	25040*	25040*	25040*	25040*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 or 3 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

1. No permit revision shall be required for increase in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400, F.A.C.
[Rule 62-213.440(1)(c)1., F.A.C.]

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title V of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(4)(i); and, Rule 62-210.200, Definitions - Applicable Requirements, F.A.C.]

A.7. Comments, notes, and justifications: None

Subsection B. This subsection addresses Acid Rain, Phase I.

{Permitting note: The U.S. EPA issues Acid Rain Phase I permit(s)}

The emissions unit listed below is regulated under Acid Rain Part, Phase I, for Florida Power Corporation, Crystal River Plant, **Facility ID No.:** 0170004, **ORIS code:** 628.

E.U. ID No.	Brief Description
002	Fossil Fuel Steam Generator, Unit 2
004	Fossil Fuel Steam Generator, Unit 4
003	Fossil Fuel Steam Generator, Unit 5

B.1. The owners and operators of these Phase I acid rain unit(s) must comply with the standard requirements and special provisions set forth in the permit(s) listed below:
a. Phase I permit dated 03/27/97.
[Chapter 62-213, F.A.C.]

B.2. Nitrogen oxide (NO_X) requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	NOx limit*
-002	2	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_X early election compliance plan for unit 2. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(1) of 0.45 lb/MMBtu" for tangentially fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(1) of 0.40 lb/MMBtu" for tangentially fired boilers until calendar year 2008. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.
-004	4	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_X early election compliance plan for unit 4. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/MMBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/MMBtu" for dry bottom wall-fired boilers until calendar year 2008. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.
-003	5	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_X early election compliance plan for unit 5. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/MMBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/MMBtu" for dry bottom wall-fired boilers until calendar year 2008. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

* Based on the Phase II NO_X Compliance Plan dated December 19, 1997.

B.3. Comments, notes, and justifications: none

FEATURES

CoalAge

Tax Credit Plants Emerge

Collecting a tax credit for producing a saleable product, Section 29 plants flourish.

By G. William Kalb

Editor's Note: Based upon the high attendance at various Section 29 presentations at Coal Prep '98 and '99 and an ongoing interest in the topic, the Advisory Board of Coal Prep 2000 has developed a half-day symposium specifically oriented to Section 29 projects. This symposium, scheduled for the Coal Prep 2000 morning session on Wednesday, May 3, in Lexington, Ky., is designed for both the exchange of information between Section 29 project participants and to provide a general background to the rest of the coal industry.

In sharp contrast to the consolidating coal industry and demise of the small operator, approximately 50 Section 29 projects have emerged during the past three years. The typical Section 29 project is designed to produce in the range of 300,000 to 500,000 tons per year (tpy) of a coal-based synthetic fuel, with the most viable operations using old slurry impoundments or fine product streams from existing preparation plants as a feedstock. Many in the industry have a concept of Section 29 projects but lack an in-depth understanding of them.

Section 29 projects came about as a result of the 1973 oil embargo by the Organization of Petroleum Exporting Countries (OPEC) and the subsequent quadrupling of the world price of oil. Congress enacted the IRS Code Section 29 Tax Credit Program in 1979 in an effort to decrease U.S. dependence on imported oil. The intent behind this tax credit program was to stimulate private investment in energy conservation, to promote energy produced from renewable resources, and to develop non-conventional energy sources. The tax credit was originally applied to a large number of fuels, including:

·Gas produced from coal seams and other non-conventional sources (landfills, etc);

·Oil from shale and tar sands;

·Steam produced from agricultural byproducts;

·Qualified, processed, wood-based fuels; and

·Liquid, gaseous, and solid coal-based synthetic fuels.

The tax credit was set in 1980 at $3 for the equivalent of each barrel of oil of a qualified fuel, with this value adjusted annually based on the inflation rate. A barrel of oil contains 5.8 million Btu, compared with a ton of a 12,000-Btu-per-lb coal containing 24 million Btu (equating to a $12.41-per-ton tax credit for each ton of synthetic coal-based fuel produced). Based on the inflation adjustment, the 1996 tax credit translated into $1.026 per million Btu (equating to a $24.62-per-ton tax credit for a 12,000-Btu-per-lb synthetic coal-based fuel). The tax credit is adjusted downwards as the price of oil increases, which, to this date, has had a very small impact on the tax credit. In 1998 the tax credit was $1.08 per million Btu which translates into a $25.92 tax credit for each ton of a 12,000-Btu-per-lb qualified synthetic coal-based fuel. The tax credit can be directly deducted, dollar for dollar, from the owners' tax bill.

A Section 29 qualified operation sells the synthetic fuel at the market price and simultaneously obtains the tax credit. In the case of a qualified synthetic coal-based fuel, the operator might sell a product for $22 per ton and then obtain a $25.92-per-ton tax credit (the tax credit is free, untaxable cash flow, assuming that the owner has the tax liability).

The program was initially utilized by the gas industry to develop gas reserves from non-conventional sources (coalbed methane, landfills, etc). It is estimated that $60 billion of investment was made in the recovery of coalbed methane, with gas production from alternative sources peaking between 1989 and 1994. Additional alternative gas production was from landfills, with this industry developed almost exclusively based on IRS Section 29. Within the gas industry, the Section 29 program resulted in significant progress being made in developing new technologies that would make the recovery of alternative sources of natural gas more economical. The Section 29 program was less visible in the oil industry because the large oil companies used the tax credits internally and Saudi Arabia had been flooding the market with oil with a lower price-per-million Btu than the cost-per-million Btu of producing oil in the United States from an alternative source (oil from shale and tar sands) minus the tax credit.

The coal industry's utilization of the Section 29 program matured slowly due to the requirement that synthetic fuel produced from coal must illustrate a chemical change, while the oil and gas industry had to produce their fuel from a less economic reserve. The first coal industry project that received a private letter ruling (the IRS' acceptance of the technology) was in 1986 for the K-Fuel process based in Gillette, Wyo. This process dried, decarboxylated, and stabilized a low-rank subbituminous coal and produced a 12,200-Btu-per-lb synthetic fuel usable in a boiler designed for bituminous coal without a derate.

Several amendments to the Section 29 IRS regulations did enhance the utilization of the coal industry's tax credit. First, the IRS program eventually was extended to include facilities that were online by June 30, 1998, with the tax credit applicable for 10 years following that date; and then a ruling by the IRS in the mid-1990s permitted the use of limited partnerships as a means of recruiting capital, decreasing the investment burden, and sharing (or selling) the tax credit.

These changes resulted in the development and commercialization of the Covol, Carbontite, Startec, Earthco, and E-Fuel processes that received favorable private letter rulings by the IRS.

Following a rush in late 1996 to sign engineering procurement contracts (a requirement for the tax credit), approximately 50 facilities claimed to be placed in service by the June 30, 1998, deadline. The major participants (multiple sites each) included Covol using a proprietary additive, Michigan Consolidated Gas using the Earthco process, Pace Carbon using the Covol process, Carbontronics using the Carbontite process, Startec using their own technology, and Duquesne Energy using the E-Fuel process (combine fine coal with waste paper and plastic byproducts).

Most of the above operations had the private letter ruling, the required engineering procurement, the construction contract, and had processed sufficient tonnage (frequently minimal) by June 30, 1998, to meet the IRS requirements. While there has been a significant falling-out of these operations, with approximately half of these original operations currently idle, it has been recognized that it is acceptable to modify various portions of the approved processes and/or to relocate these facilities. As a result, modifications are being made to the plants and a secondary market is developing for the relocation of those facilities that either were not economically viable or had a feedstock not amenable to the specific process.

With the exception of K-Fuels, Encoal, and Western Syncoal, most of the projects utilize a fine-coal feedstock (frequently from idle or active slurry impoundments) mixed with various additives and binders, followed by an agglomeration and drying process. A major positive result of the Section 29 projects has been the re-evaluation of various coal agglomeration systems including extrusion, pelletizing, and briquetting. Several of the ongoing modifications of the Section 29 approved facilities include the installation of alternative agglomeration processes (frequently briquetters replacing or augmenting pelletizing systems).

The re-evaluation of agglomerating systems for fine coal has major implications in the development of new clean coal technologies. Agglomeration of coal fines was a major U.S. business between 1900 and 1955 when stoker-sized coal was the dominant fuel for home heating/cooking, locomotives, and steam generating plants (for both power and industrial use). During this time period large amounts of otherwise nonusable fine coal (minus 1/4 inch) was binder briquetted as a stoker-sized fuel. However, the coal briquetting industry disappeared in North America with the advent of diesel locomotives, natural gas supply to homes, and pulverized fuel-fired power stations.

Today, with the current emphasis on environmental emissions, in conjunction with coal utilization and depletion of higher quality coal reserves, there is an increased need to deep clean coal (crush the preparation plant feedstock to a finer topsize to liberate more impurities). The deep cleaning approach requires the subsequent re-agglomeration of the beneficiated fine coal, with the Section 29 projects providing the commercial scale re-evaluation of these agglomeration processes. As a result of the Section 29 program, significant progress has been made in the development of lower-cost binder briquetting systems and binderless coal briquetting systems. The enhancement of these technologies significantly impact the future development of deep cleaning coal technologies and biomass type fuels.

The IRS program objective was to encourage the development of new technologies to economically recover alternative sources of fuel. The tax credits have a limited lifespan with the objective that the more viable sources of alternative fuels would eventually become economical without the tax credit.

Presently, the program for coal-based synthetic fuels remains very much alive and is in the process of recuperating, with facilities being relocated or modified to become commercially viable. It is anticipated that the tax credit program will be active through the 2008 deadline and various aspects/technologies developed for this program will eventually become economically viable without the supporting tax credit.

Kalb is president of Tra-Det Inc. located in Wheeling, W.Va. Contact at: 304/242-2092.

return to top of tax credit feature

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 21-Apr-2000 08:43am
From: Mike Halpin TAL
HALPIN_M
Dept:
Tel No:

To: Walker, Jeff (Jeff.Walker@gen.pge.com)

Subject: Re: Cedar Bay Info Request

Jeff -
Good to hear from you. Coincidentally, I was planning to contact you about an issue that I am following which PG&E has some knowledge of in California. I'll ask my question after my responses to yours below:

Info request:

1. Can you direct me to a particular statute or guidance document that delineates what constitutes actual start-up parameters in boilers. Is there any specific mmBtu,opacity, CO2 level. etc. that when reached actually gives the boiler an on-line status. Cedar Bay's has several parameters incorporated into the CEM system that when reached, will designate that the boiler has formally transitioned from an off-line to a start-up/on-line status. I am not aware of the source of the start-up criteria and I would like a warm feeling that all is well here.

Since your question deals with CEMS, the direct answer to your question is that a boiler is "on-line" whenever it has heat input. See 40CFR75 SubPart B and I believe that 40CFR75.10(c) and (d) would provide the specific detail.

2. Corporate PG&E Gen is under the impression that a utility(either Florida Power or TECO) has proposed to do a test burn on a coal product that we have recently talked about, synfuel. Can you or are you able to validate if this is true and if you are able, can you advise me of the tentative date of the proposed test burn?

From what I have learned, FPC Crystal River has this approved in their permit. Apparently, they submitted an application and it was determined to not trigger PSD. I'm attaching 3 files for your use. Two of them deal with the PSD analysis and the 3rd is a copy of Crystal River's Title V permit. To my knowledge, a test burn was not completed.

3. Speaking of test burns, are test burn protocols that have been submitted to the DEP public record and if they are, what would be the most expeditious manner to obtain copies?

Any applications would be a matter of public record, but would require someone (from your office) to look through our files, as most of these documents are not electronically available. I do not believe that there are any standards regarding test protocols and am unaware of any recent test burns.
I believe that a few years ago, someone did a test burn for a blend of petcoke, and prior to that there was FPL's Orimulsion test. As you can

imagine, each case has its own issues, therefore I would advise:
1) If you decide you want to do a test, decide what you (PG&E) want to find out about it and come visit us (as in a meeting).
2) We'll suggest the things that we'll want, which will allow an application to be put together.

Alternately, you may be satisfied with what Crystal River has in their permit. In that case, you will need to show that PSD is not triggered and could try to get your Title V permit revised. If you wish to discuss this further, call me.

Now, here's my question - I am looking at a technology called SCONOx for a facility in Florida (operated by a competitor of yours). PG&E has incorporated this technology within an application at Otay Mesa (in California) and I've attached an article from the San Diego Union Tribune which notes this. I am trying to get my hands on (very quickly!) an estimate of the cost differential between SCR and SCONOx for a 175 MW (F frame) turbine. This is precisely what PG&E has applied for and thus my question - can you obtain this info for me?

Any info would be helpful.

Thanks
Mike

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. **Applicant**

   Florida Power Corporation
   3201 34th Street South
   St. Petersburg, Florida 33711

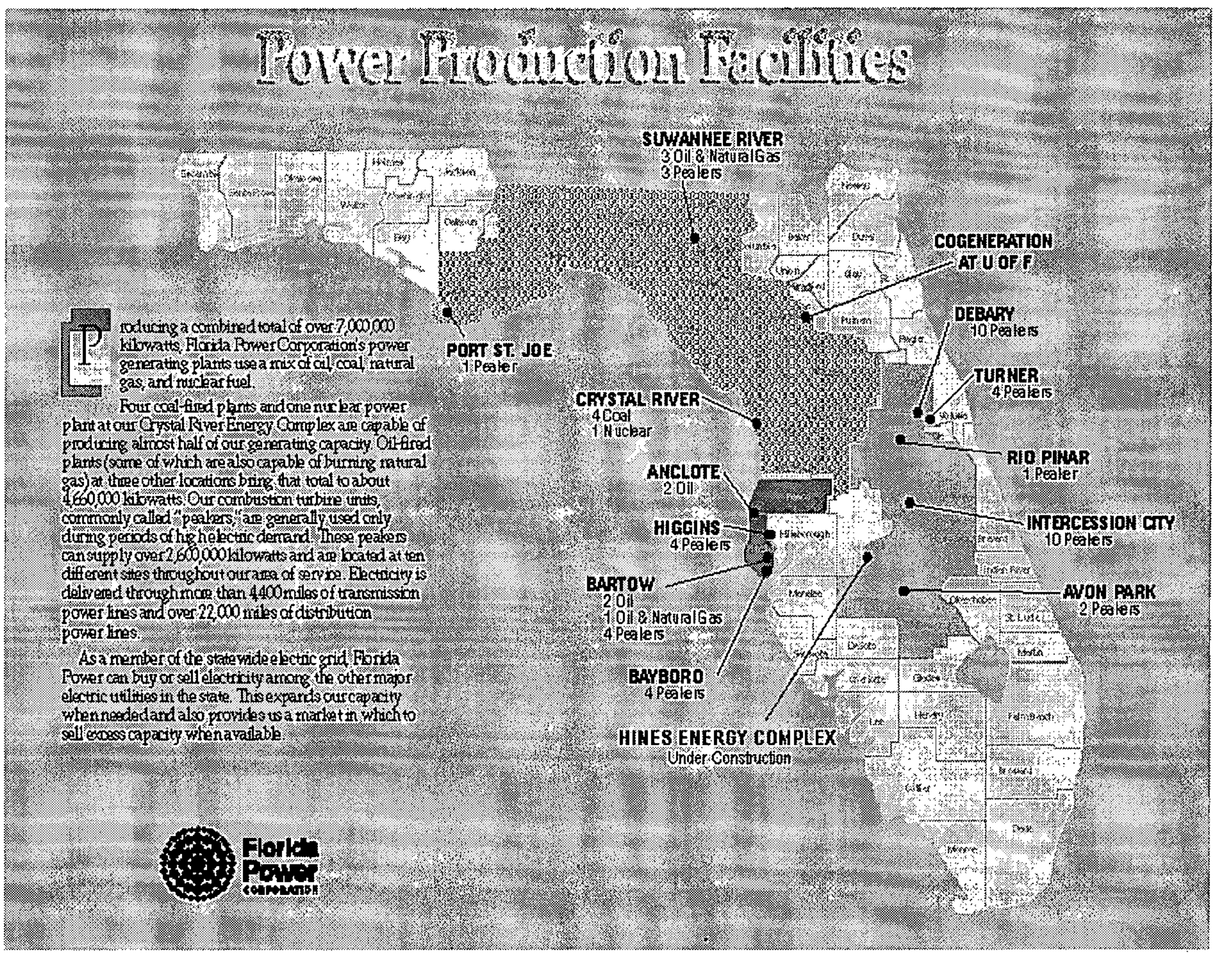
   Authorized Representative: W. Jeffrey Pardue, CEP

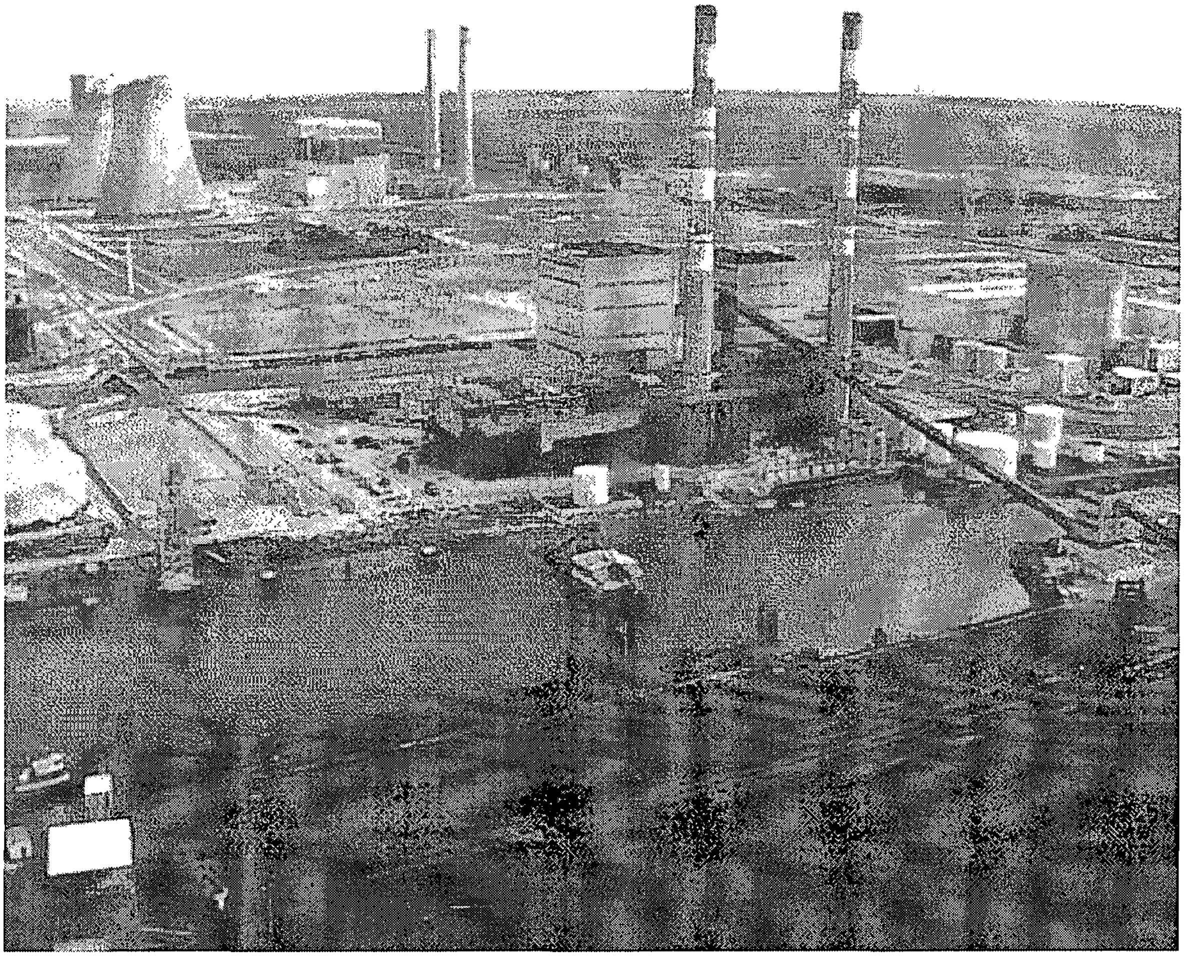
2. **Source Name and Location**

   Crystal River Plant
   Units 1, 2, 4, and 5
   Crystal River, Citrus County

   UTM Coordinates: Zone 17, 334.3 km East and 3204.5 km North. The plant is located on the Gulf of Mexico, approximately 7.5 miles Northwest of Crystal River, Citrus County.

   The location of the Crystal River Plant within the FPC system is shown below followed by a photograph of the site downloaded from the FPC website.





Units 1 and 2 are in the foreground while Units 4 and 5 are in the background. The nuclear-powered:Unit 3 is to the right of Units 1 and 2.

3. Source Description

The Florida Power Corporation (FPC) Crystal River Plant consists of four steam electrical generating units. Units 1 and 2 are described in company information as coal units with net generating capacities of 373 and 469 megawatts respectively. Each unit has a 500 foot stack and employs saltwater cooling. Units 4 and 5 are also coal units with net generating capacities of 717 MW, 600 foot stacks, and 440 foot saltwater cooling towers.

4. Current Permit and Major Regulatory Program Status

Construction of Units 1 and 2 preceded most Federal and State clean air programs and began operation in 1966 and 1969 respectively. Construction of Units 4 and 5 was authorized by EPA Prevention of Significant Deterioration (PSD) Permit No. PSD-FL-007 and Florida Power Plant Site Certification PA77-09 and began operation in 1982 and 1984 respectively.

The four units are regulated under EPA's Title IV Acid Rain Program and are subject to the State of Florida's Major Source (Title V) Operation Permit requiements. An application for a facility-wide Title V operation permit was submitted by FPC in mid-1996. Conditions are still being negotiated between the Department and FPC.

5. Permit Modification Request

On February 24, 1998 the Department received a request from FPC for modification of its permits to add coal briquettes to the list of fuels authorized to be burned in Units 1, 2, 4, and 5. The briquettes will be produced from discarded coal fines from the mines that currently supply the coal for Units 1, 2, 4, and 5. Coal fines will be bound under heat and pressure with a small amount of Bunker C oil to produce briquettes that can be handled, combined, shipped and burned with the regular coal supply. Because the briquettes are produced from the same mines as the regular coal supplies, the chemical analyses of the briquettes and coal are similar.

Because the Bunker C oil used as a binder can actually have a higher sulfur content than the coal, even its less than one percent presence in the blended fuel could increase sulfur dioxide emissions from the plant by as much as 2,250 tons per year by Department estimates. Therefore FPC proposes to blend additional low sulfur coal into the regular coal supplies for the four units such that the average sulfur content will be maintained at the historical average from the past three years. FPC asserts and the Department accepts that burning briquettes will not cause measurable emissions increases and that a review for the Prevention of Significant Deterioration of Air quality (PSD) is not required.

6. Emissions Increases Due to Modification/Method of Operation

Because the main components of the units, including the compressors, combustors, rotors, fuel system, etc., will not be modified, it is arguable that the inlet foggers are not physical modification of the units. However the foggers are physical pieces of equipment whose addition and use can increase emissions on hot or dry days. The use of the foggers can also be considered a change in method of operation of the inlet "air conditioning system" that is already used to filter incoming air.

FPC estimated the maximum emissions increases by using the heat-input increase associated with a 20 degree F decrease in compressor inlet temperature. Using the heat input curve, a 20-degree F temperature decrease results in an increase in heat input of 60 mmBtu per hour. This value is multiplied by the emission rate in lb/mmBtu to obtain hourly emissions increases. The results are summarized below together with annual emission increase estimates, based on 1,750 hours of operation per fogger per year. The estimates are based on fuel oil firing and would be substantially less when firing natural gas.

TOTAL EMISSIONS INCREASES DUE TO USE OF INLET FOGGERS AT FOUR UNITS

Pollutant	Emission Rate lb/mmBtu	Emission Increase lb/hr	Annual Increase tons/yr	PSD Threshold tons/yr
NO_x	See Curve	11	39	40
PM/PM_{10}	0.015	0.9	3	25/15
CO	0.05	3	11	100
VOC	0.004	0.2	1	40
SO_2	0.19	11	40	40
SAM	0.016	1	3	7

The emissions increases calculated are the direct result from the modification or change in method of operation. These assume that the ability to achieve greater power output when the foggers are used does not result in the increased usage of the peaking units. The rationale is discussed below.

7. **Evaluation of PSD Applicability**

As a major source, a modification or change in method of operation of Units P7-P10 resulting in **significant net emissions increases** is subject to PSD review. Significant net emissions increase is defined in Rule 62-212.400, F.A.C as follows:

> *Significant Net Emissions Increase – A significant net emissions increase of a pollutant regulated under the Act is a* ***net emissions increase*** *equal to or greater than the applicable significant emission rate listed in Table 212.400-2, Regulated Air Pollutants – Significant Emission Rates.*

The significant emission rates are included (see PSD Threshold) in the Table above. The meaning of a net emissions increase is given in Rule 62-212.400, F.A.C. as:

> *Net Emissions Increase - A modification to a facility results in a net emissions increase when, for a pollutant regulated under the Act, the sum of all of the contemporaneous creditable increases and decreases in the* ***actual emissions*** *of the facility, including the increase in emissions of the modification itself and any increases and decreases in quantifiable fugitive emissions, is greater than zero.*

The definition of actual emissions is given in Rule 62-210.200, F.A.C. (definitions) as follows:

> *Actual Emissions - The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:*
>
> *(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.*
>
> *(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.*
>
> *(c) For any emissions unit (other than an electric utility steam-generating unit specified in subparagraph (d) of this definition) which has not begun* ***normal operations*** *on a particular date, actual emissions shall equal the* ***potential emissions*** *of the emissions unit on that date.*

The term normal operations appears to be undefined and subject to some interpretation. Potential emissions are defined as follows:

> *Potential Emissions or Potential to Emit - The maximum capacity of an emission unit or facility to emit a pollutant under its physical and operational design. Any enforceable physical or operational limitation on the capacity of the emission unit or facility to emit a pollutant, including any air pollution control equipment and any restrictions on hours of operation or on the type or amount of material combusted, stored, or processed shall be treated as part of its design provided that, for any regulated air pollutant, such physical or operational limitation is federally enforceable.*

Actual hours of operation since the start of operations are as follows:

Annual Operating Hours 1993 - 1998

Unit/Year	1993	1994	1995	1996	1997	1998
P-7	193	873	649	1125	1996	1927
P-8	222	724	562	1269	1974	1796
P-9	68	697	715	1177	2031	1981
P-10	155	579	512	1186	1893	2015

There has been a steady increase in annual hours of operation since these units were installed in 1993. During 1997 and 1998, these units were each utilized between 1,796 and 2031 hours per year or more than half of the 3,390 permitted hours of operation per unit per year.

Although recent hours of operation are well below the permitted limits, they are actually fairly high compared with the typically low levels of operation characteristic of peaking units. Among the reasons for the relatively high levels are the prolonged shutdown of the baseloaded Crystal River Nuclear Unit 3 in 1997, the very hot summer of 1998, and the recognized low electrical power reserve margin in the State.

If these peaking units were being entirely replaced by larger units, it would be clear that they have not begun normal operations. In such a case, a comparison of future to past actual emissions would be based on a comparison of potential emissions to past actual emissions. Such a comparison would undoubtedly result in a determination that PSD is applicable unless the company took an extreme limitation in hours of operation.

If a like-kind replacement was being made, the same comparison would also result in a determination that PSD is applicable. That particular case was addressed for the purposes of comparison to the specific case addressed in the Puerto Rican Cement Decision. This is the watershed Federal Circuit Court of Appeals decision that upheld the past actual-to-potential emission comparison applicable to (at least) modernization projects. The comments of interest for the purposes of the present review are as follows:

> *"One can imagine circumstances that might test the reasonableness of EPA's regulation. An electricity company, for example, might wish to replace a peak load generator -- one that operates only a few days per year -- with a new peak load generator that the firm could, but almost certainly will not, operate every day. And, uncertainties about the precise shape of future electricity peak demand might make the firm hesitate to promise EPA it will never increase actual emissions (particularly since EPA insists, as a condition of accepting the promise and issuing the NAD, that the firm also promise not to apply for permission for an actual increase under the PSD review process). Whatever the arguments about the "irrationality" of EPA's interpretation in such circumstances, however, those circumstances are not present here. The Company is not interested in peak load capacity; it operated its old kilns at low levels in the past; its new, more efficient kiln might give it the economic ability to increase production; consequently, EPA could plausibly fear an increase in actual emissions were it to provide the NAD. Thus, this seems the very type of case for which the regulations quoted above were written. We can find nothing arbitrary or irrational about EPA applying those regulations to the Company's proposal."*

The FPC inlet fogger project is yet another step removed from a modernization project than the like-kind replacement example. The units will not be replaced at all. The modification and its effects can be isolated and directly estimated. The Department believes that the peaking units have begun normal operation. The addition of the inlet foggers will not change that fact or cause an increase in hours of operation. The modification itself (i.e. installation and operation of the foggers), however, has not yet begun normal operation and its future actual emissions based on potential to emit should be initially estimated assuming usage of the units at full capacity during the permitted 3,390 hours per unit per year.

The number of days during which the foggers can economically operate probably limits actual emissions increases to levels below significance for the purposes of PSD applicability. However, FPC proposes to limit operation of the foggers to 1,750 hours per unit per year. This value is approximately equal to the recent historical hours of operation for the four peaking units. It is also a clear indication that compressor air inlet cooling will not cause the units to operate all of the permitted hours. Emissions will increase under these limitations (as previously tabulated) by levels less than the significant emissions rates. The Department concludes, therefore that PSD does not apply to this project.

8. Proposed Addition of New Conditions to Permit PSD-FL-180

The construction permit has expired for the Intercession City Project to construct Units P7 through P11. The Department will re-issue the permit incorporating all other previously approved revisions and modifications to-date and will add a further condition authorizing installation and operation of the inlet foggers.

The new condition applicable to the inlet foggers proposed for Units P7 through P10 are shown in the draft re-issued and modified permit. It limits operation of the inlet foggers to 1,750 hours per unit per year.

9. Conclusions

The changes authorized by this permit modification will not cause increases in hours of operation and will not result in significant net emissions increases. The project will not increase the maximum short-term emission rates as these are already achieved under natural conditions of low ambient temperatures without the use of the foggers.

The Department concludes that PSD is not applicable to this project. The changes will not cause a significant impact or cause or contribute to a violation of any ambient air quality standard or PSD increment.

The Department's conclusion does not set a precedent for projects implemented at any facilities other than simple cycle peaking units. It does not set precedents related to any physical changes within the compressors, combustors, rotors, or other key components at such units. The application and determination of the Department's rules does not constitute an interpretation of the EPA rules under 40CFR52.21, Prevention of Significant Deterioration or 40CFR60, New Source Performance Standards.

PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATIONS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File Nos. 01740004-005-AC, PSD-FL-007

Florida Power Corporation Crystal River Plant
Units 1, 2, 4, 5 Coal Briquettes Project
Citrus County

The Department of Environmental Protection (Department) gives notice of its intent to issue Permit Modifications to Florida Power Corporation (FPC). The permit is to burn a maximum 20 percent blend of coal fines briquettes with coal by weight at the Crystal River Plant in Citrus County. A Best Available Control Technology (BACT) determination was not required pursuant to Rule 62-212.400, F.A.C. or 40 CFR52.21. The applicant's name and address are Florida Power Corporation, Post Office Box 14042, MAC BB1A, St. Petersburg, Florida 33733.

The briquettes will be produced from discarded coal fines from the mines that currently supply the coal for Units 1, 2, 4, and 5. Coal fines will be bound under heat and pressure with a small amount of Bunker C oil to produce briquettes that can be handled, combined, shipped and burned with the regular coal supply. Because the briquettes are produced from the same mines as the regular coal supplies, the chemical analyses of the briquettes and coal are similar.

Because the Bunker C oil used as a binder can actually have a higher sulfur content than the coal, even its less than one percent presence in the blended fuel could increase sulfur dioxide emissions from the plant by as much as 2,250 tons per year by Department estimates. Therefore FPC proposes to blend additional low sulfur coal into the regular coal supplies for the four units such that the average sulfur content will be maintained at the historical average from the past three years. FPC asserts and the Department accepts that burning briquettes will not cause measurable emissions increases and that a review for the Prevention of Significant Deterioration of Air quality (PSD) is not required.

An air quality impact analysis was not required or conducted. No significant impacts are expected to occur as a result of this project. It will not cause or contribute to a violation of any ambient air quality standard or increment.

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southwest District Office
3319 Maguire Boulevard, Suite 232
Tampa, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-5963

The complete project file includes the application, technical evaluation, Draft Permit Modifications, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 29, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffery Pardue
Director, Environmental Services Department Director, Environmental Services Department
Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

Re: DEP File No. 0170004-006-AC, Modification of Permit No. 0170004-003-AC, PSD-FL-007
Crystal River Power Plant

The applicant, Florida Power Corporation, Crystal River Power Plant, applied on March 24, 1999, to the Department for a modification to air construction permit number 0170004-003-AC for its Crystal River Power Plant located west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The modification is to include a coal/briquette mixture as an allowable fuel in Crystal River Units 1,2,4, and 5. The briquettes will be blended with some of the regular coal supply and Florida Power Corporation states the sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

OPERATIONAL REQUIREMENTS

1. Hours of Operation: These emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

2. Fuel: The emissions units described above may combust a mixture of coal and coal briquettes. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

3. Sulfur Limitation: The maximum sulfur content of the coal/ briquette mixture shipment, averaged on an annual basis, shall not exceed the following:[Requested by Applicant in the application received March 24, 1999]

Emissions Unit No.	Emissions Unit Description	Average Percent Sulfur Limit, By Weight
001	Fossil Fuel Steam Generator (FFSG), Unit 1	1.05%
002	FFSG, Unit 2	1.05%
004	FFSG, Unit 4	0.68%
003	FFSG, Unit 5	0.68%

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

4. The permittee shall demonstrate compliance with the fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. See specific conditions 3 and 5.
[Rule 62-213.440, F.A.C.]

5. Sulfur Dioxide - Fuel Sampling. The following fuel sampling and analysis program shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the fuel sulfur standard:
   a. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using appropriate ASTM methods such as, ASTM D2013-72, ASTM D3177-75, and ASTM D4239-85, or latest ASTM edition methods, to analyze a representative sample of coal following each fuel delivery.
   b. Record daily the amount of coal fired, the density of each fuel, the Btu value, and the percent sulfur content by weight of each fuel.
   c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rule 62-213.440, F.A.C.]

6. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

REPORTING AND RECORD KEEPING REQUIREMENTS

7. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

[Rule 62-213.440(1)(b)2.b., F.A.C.]

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6-30-99 to the person(s) listed:

* W. Jeffrey Pardue, Florida Power Corporation
Mike Kennedy, Florida Power Corporation
Gerald Kissel, P.E., DEP, Southwest District
Hamilton S. Oven, P.E., DEP

Clerk Stamp

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

Kim Tober 6-30-99
(Clerk) (Date)

FINAL DETERMINATION

Florida Power Corporation
Crystal River Power Plant
Citrus County
Coal/Briquette Fuel Mixture

Permit No. 0170004-006-AC

An "Intent to Issue an Air Construction Permit" to allow the combustion of a coal/briquette fuel mixture to Florida Power Corporation for the Crystal River Power Plant located west of U. S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County was clerked on May 25, 1999. The "Public Notice of Intent to Issue Air Construction Permit" was published in the Citrus County Chronicle on June 3, 1999. The draft Air Construction Permit was available for public inspection at the Department of Environmental Protection's Southwest District office in Tampa,and the permitting authority's office in Tallahassee. Proof of publication of the "Public Notice of Intent to Issue Air Construction Permit" was received on June 24, 1999.

Comments were received and the draft Air Construction Permit was changed. The comments were not considered significant enough to reissue the draft Air Construction Permit and require another Public Notice. Comments were received from one respondent, Mr. J. Michael Kennedy of Florida Power Corporation, during the 14 (fourteen) day public comment period. Listed below is each comment and the response.

Condition 3. Sulfur Limitation.

Comment: Could we add the word "shipments" after the word "mixture" to ensure that it's clear that we're talking about the shipments we receive (as opposed to the separate regular coal shipments)? It is written that way in the Technical Evaluation, so reflecting it in the permit would be consistent.

Response: The Department agrees with the comment and will add the word "shipments" after the word "mixture".

Comment: In the table, Emissions Unit No. 3 is actually FFSG, Unit 5. Unit 3 is the nuclear unit.

Response: The Department agrees with the comment and Emissions Unit 003 will identified as FFSG Unit 5.

Comment: The question the folks in fuel supply have asked is if we could write the sulfur limit in terms of lb/mmBtu for the coal/briquette shipments rather than %sulfur. They said that some of the coal we get is high in Btu content, and the lb/mmBtu approach would provide some flexibility without increasing the emission rate. What do you think?

Response: After Florida Power Corporation provides equivalency information, the Department will express the limits in terms of pounds per million Btu, heat input.

The final action of the Department will be to issue the permit covered by the public notice as proposed except for the changes noted above.

Florida Power
CORPORATION

RECEIVED

JUN 24 1999

BUREAU OF
AIR REGULATION

June 22, 1999

Mr. Ed Svec
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

0170004-006-AC

Dear Mr. Svec:

Re: Crystal River Coal Briquettes - Proof of Publication

I have enclosed the proof of publication of the Public Notice of Intent to Issue Air Construction Permit Modification for the coal briquettes project at Florida Power Corporation's Crystal River Units 1 and 2.

Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

Proof Of Publication

from the

CITRUS COUNTY CHRONICLE

Crystal River, Citrus County, Florida

PUBLISHED DAILY

STATE OF FLORIDA
COUNTY OF CITRUS

Before the undersigned authority personally appeared FELICIA H. SATCHELL of the Citrus County Chronicle, a newspaper published daily at Crystal River, in Citrus County, Florida, that the attached copy of advertisement being a public notice in the matter of the

FILE NO. 0170004-006-AC

Court, was published in said newspaper in the issues of

JUNE 3, 1999

Affiant further says that the Citrus County Chronicle is a newspaper published at Crystal River in said Citrus County, Florida, and that the said newspaper has heretofore been continuously published in Citrus County, Florida, each week and has been entered as second class mail matter at the post office in Inverness in said Citrus County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Felicia H. Satchell

The forgoing instrument was acknowledged before me this 3th day of JUNE 19 99 by FELICIA H. SATCHELL who is personally known to me and who did take an oath.

Jeanette A Schmidt

Notary Public

NOTARY PUBLIC STATE OF FLORIDA
Jeanette A Schmidt
Notary Public, State of Florida
Commission No. CC 669909
My Commission Exp. 08/16/2001
1-800-3-NOTARY - Fla. Notary Service & Bonding Co.

1420603 THCRN
PUBLIC NOTICE
OF INTENT TO ISSUE
AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL REGULATION
DEP File No. 0170004-006-AC
Florida Power Corporation
Crystal River Plant
Citrus County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Florida Power Corporation, for the Crystal River Plant located west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The permit is to allow the combustion of a coal/briquette fuel mixture in Crystal River Units 1, 2, 4 and 5. The applicant's mailing address is: Florida Power Corporation, 3201 34th Street South, St. Petersburg, Florida 33711. A Best Available Control Technology (BACT) determination was nor required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

The briquettes are produced from coal fines at the mines, currently supplying coast to Crystal River Units, 1, 2, 4 and 5. The coal fines are combined under heat and pressure with a small amount of oil to form the briquettes. The oil acts as a binding agent. The heat and pressure removes moisture and produces the briquettes. The briquettes will be blended with some of the regular coal supplied to Florida Power Corporation. The sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. Sulfur content of the mixture shall not exceed 1.05 %, percent by weight and annual average, for Crystal River Units 1 and 2; and 0.68 % percent by weight and annual average, for Crystal River Units 4 and 5. The combustion of this fuel mixture will result in no actual increases of sulfur dioxide.

This project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity.

Any air quality impact analysis was not conducted. Emissions from the facility will not consume PSD increment and will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The Department will issue the Final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station # 5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

Mediation is not available is this proceeding.

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

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

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

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

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

Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southwest District
Suite 4, 111 S. Magnolia Drive	3804 Coconut Palm Drive
Tallahassee, Florida 32301	Tampa, Florida 33619-8218
Telephone: 850/488-0114	Telephone: 813/744-6100
Fax 850/922-6979	

The complete project file includes the application, technical evaluations, Draft permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Source Review Section, or the Department's reviewing engineer for this project, Edward J. Svec, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Published one (1) time in the Citrus County Chronicle: Thursday, June 3, 1999.

INTEROFFICE MEMORANDUM

Date: 07-Jun-1999 04:54pm
From: J-Michael.Kennedy
J-Michael.Kennedy@fpc.com
Dept:
Tel No:

To: svec_e (svec_e@dep.state.fl.us)

Subject: Coal Briquettes

Ed,

I have reviewed the coal briquettes draft permit and had a couple of minor comments, plus one question.

Condition 3. Sulfur Limitation

Could we add the word "shipments" after the word "mixture" to ensure that it's clear that we're talking about the shipments we receive (as opposed to the separate regular coal shipments)? It is written that way in the Technical Evaluation, so reflecting it in the permit would be consistent.

In the table, Emissions Unit No. 3 is actually FFSG, Unit 5. Unit 3 is the nuclear unit.

The question: The folks in fuel supply have asked if we could write the sulfur limit in terms of lb/mmBtu for the coal/briquette shipments rather than %sulfur. They said that some of the coal we get is high in Btu content, and the lb/mmBtu approach would provide some flexibility without increasing the emission rate. What do you think?

I don't have the proof of publication yet, but should have it very soon, and I'll send it to you then.

Thanks.

Mike Kennedy
(727) 826-4334

RFC-822-headers:
Received: from epic5.dep.state.fl.us ([199.73.143.30])
by mail.epic1.dep.state.fl.us (PMDF V5.2-32 #37980)
with ESMTP id <01JC4JOUFILO9ANB29@mail.epic1.dep.state.fl.us> for
SVEC_E@a1.epic1.dep.state.fl.us (ORCPT rfc822;svec_e@dep.state.fl.us); Mon,
7 Jun 1999 16:54:21 EDT
Received: from fpc.com ([199.184.211.2]) by mail.epic5.dep.state.fl.us
(PMDF V5.2-32 #31508)
with SMTP id <01JC4JUJGX8K0008Q5@mail.epic5.dep.state.fl.us> for
SVEC_E@a1.epic1.dep.state.fl.us (ORCPT rfc822;svec_e@dep.state.fl.us); Mon,
07 Jun 1999 16:58:57 -0400 (EDT)
Received: from by fpc.com (4.1/SMI-4.1) id AB04242; Mon,
07 Jun 1999 15:50:47 -0500 (EST)
Received: from localhost (root@localhost)
by sv003.fpc.com (8.8.6 (PHNE_14041)/8.8.6) with SMTP id QAA26376 for
svec_e@dep.state.fl.us; Mon, 07 Jun 1999 16:34:15 -0400 (EDT)
Content-disposition: inline; filename="cc:Mail"
X-Openmail-Hops: 1

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 25, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffrey Pardue
Director, Environmental Services Department
Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33711

Re: DEP File No. 0170004-006-AC
Crystal River Power Plant
Coal/Briquette Fuel Mixture

Dear Mr. Pardue:

Enclosed is one copy of the Draft air construction permit for the Crystal River Plant located west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The Technical Evaluation and Preliminary Determination, the Department's Intent to Issue Air Construction Permit and the Public Notice of Intent to Issue Air Construction Permit are also included.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Edward J. Svec at 850/921-8985 or Mr. Linero at 850/921-9523.

Sincerely,

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

CHF/s

Enclosures

In the Matter of an
Application for Permit by:

Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33711

DEP File No. 0170004-006-AC
Crystal River Power Plant
Citrus County
Coal/Briquette Fuel Mixture

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

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

The applicant, Florida Power Corporation, applied on March 24, 1999 to the Department for an air construction permit for its Crystal River Plantlocated west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The permit is to allow the combustion of a coal/briquette fuel mixture in Crystal River Units 1,2,4, and 5. The briquettes will be blended with some of the regular coal supply and Florida Power Corporation states the sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years.The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to allow the combustion and to restrict the sulfur content of the coal/briquette fuel.

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

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

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5-25-99 to the person(s) listed:

* W. Jeffrey Pardue, Florida Power Corporation
Mike Kennedy, Florida Power Corporation
Gerald Kissell, P.E., DEP, Southwest District
Hamilton S. Oven, P.E., DEP

Clerk Stamp

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

Kim Tobin 5-25-99
(Clerk) (Date)

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Jeffrey Pardue
FPC
3201 34th St. South
St. Pete, Fl 33711

4a. Article Number
Z 333 618 153

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

7. Date of Delivery
MAY 28 1999

5. Received By: *(Print Name)*

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

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

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

Thank you for using Return Receipt Service.

Z 333 618 153

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Jeff Pardue	
Street & Number FPC	
Post Office, State, & ZIP Code St. Pete Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-25-99 0170004-006AC	

PS Form **3800**, April 1995

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0170004-006-AC

Florida Power Corporation
Crystal River Plant
Citrus County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Florida Power Corporation, for the Crystal River Plantlocated west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The permit is to allow the combustion of a coal/briquette fuel mixture in Crystal River Units 1,2,4, and 5. The applicant's mailing address is: Florida Power Corporation, 3201 34th Street South, St. Petersburg, Florida 33711. A Best Available Control Technology (BACT) determination was not required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

The briquettes are produced from coal fines at the mines currently supplying coal to Crystal River Units 1,2,4 and 5. The coal fines are combined under heat and pressure with a small amount of oil to form the briquettes. The oil acts as the binding agent. The heat and pressure removes moisture and produces the briquettes. The briquettes will be blended with some of the regular coal supplied to Florida Power Corporation. The sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. Sulfur content of the mixture shall not exceed 1.05%, percent by weight and annual average, for Crystal River Units 1 and 2; and 0.68%, percent by weight and annual average, for Crystal River Units 4 and 5. The combustion of this fuel mixture will result in no actual increases of sulfur dioxide.

This project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity.

An air quality impact analysis was not conducted. Emissions from the facility will not consume PSD increment and will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The Department will issue the Final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

Mediation is not available in this proceeding.

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

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

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

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

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

Dept. of Environmental Protection Bureau of Air Regulation Suite 4, 111 S. Magnolia Drive Tallahassee, Florida, 32301 Telephone: 850/488-0114 Fax: 850/922-6979	Dept. of Environmental Protection Southwest District 3804 Coconut Palm Drive Tampa, Florida 33619-8218 Telephone: 813/744-6100

The complete project file includes the application, technical evaluations, Draft permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Source Review Section, or the Department's reviewing engineer for this project, Edward J. Svec, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Florida Power Corporation
Crystal River Power Plant
Coal/Briquette Fuel Mixture
Citrus County

DEP File No. 0170004-006-AC

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

May 24, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33711

Authorized Representative: Mr. W. Jeffery Pardue, Director, Environmental Services Department

1.2 REVIEWING AND PROCESS SCHEDULE

March 24, 1999	Received permit application and fee
March 24, 1999	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located on Power Line Road, West of U.S. Hwy. 19, Crystal River, Citrus County. The UTM coordinates are Zone 17, 334.3 km East and 3204.5 km North. This site is approximately 10 kilometers from the Chassahowitzka National Wilderness Area, a Class I PSD Area.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

Major Group No.	49	Electric, Gas, and Sanitary Services
Industry Group No.	491	Electric Services
Industry No.	4911	Electric Services

2.3 FACILITY CATEGORY

This facility consists of a nuclear unit (Unit 3); four coal-fired fossil fuel steam generating (FFSG) units with electrostatic precipitators(Units 1, 2, 4 and 5); two natural draft cooling towers for FFSG Units 4 and 5; helper mechanical cooling towers for FFSG Units 1, 2 and 3; coal-, fly ash-, and bottom ash-handling facilities; and, three relocatable diesel fired generators.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

This facility is a major source of hazardous air pollutants (HAPs) and is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

3. PROJECT DESCRIPTION

This project addresses the following emissions unit(s):

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
001	Fossil Fuel Steam Generator (FFSG), Unit 1
002	FFSG, Unit 2
004	FFSG, Unit 4
003	FFSG, Unit 5

The applicant proposes to burn a mixture of coal and coal briquettes in the four coal fired units. The coal briquettes are produced from coal fines at the mines that currently supply the coal combusted in Crystal River Units 1, 2, 4, and 5. Coal fines are combined under heat and pressure with a small amount of oil (maximum of 5% sulfur Bunker C oil) at the mine. The oil acts as the binding agent for the coal fines. Subjecting the coal fines and oil to heat and pressure removes moisture and produces coal briquettes, which have the appearance of small chunks of coal that can be handled and burned with the regular coal supply. Florida Power Corporation would receive the briquettes in shipments blended with some of the regular coal supply. In order to ensure that the addition of the coal briquettes does not result in a potential increase in emissions over past actual emissions due to the sulfur content of the Bunker C oil, the applicant has committed to limiting the sulfur content of these shipments. The sulfur content, percent by weight and as averaged on an annual basis, of the shipments of the coal/briquette fuel mixture, will not exceed 1.05% for Units 1 and 2, and will not exceed 0.68% for Units 4 and 5. These values are based on daily coal samples averaged over the calendar year for years 1996, 1997 and 1998.

4. PROJECT EMISSIONS

The emissions associated with this project are Sulfur Dioxide (SO_2).

The following table summarizes the potential maximum emissions increases of air pollutants, comparing past actual to future potential emissions in TPY:

Pollutant	Past Actual Existing Fuel	Future Potential New Fuel	Maximum Emissions Change	PSD Significance Levels [1]	Subject to PSD Review?
SO_2	86900	86900	0	40	No

[1] Florida Administrative Code (F.A.C.), Table 212.400-2.

The proposed project results in no net emissions change or less-than-significant increases in PSD pollutants. Therefore, the modification is not subject to PSD New Source Review (NSR) pursuant to Rule 62-212.400(5), F.A.C.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297, F.A.C.

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for the criteria pollutants ozone, PM_{10}, carbon monoxide, sulfur dioxide, and nitrogen dioxide.

The proposed project is not subject to PSD NSR under Rule 62-212.400(5), F.A.C., as discussed above.

Rule 62-4.030, F.A.C., prohibits modification of any existing emissions unit without first receiving a permit. It further specifies that a permitted installation may only be modified in a manner that is consistent with the terms of such a permit. Rule 62-210.200, F.A.C., defines "modification" to mean generally a change that results in an increase in actual emissions of regulated air pollutants. As discussed above, emissions would increase without the applicant requesting a restriction in the sulfur content. Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C., also reiterate the requirement for construction permits. As noted above, future potential emissions were estimated based on unrestricted operation of the emissions units. Since future potential emissions were estimated with no restrictions on operating hours, such limits are not required in the construction permit for this project.

The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules.

5.1 STATE REGULATIONS

Chapter 62-4	Permits
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.360	Designation of Prevention of Significant Deterioration Areas
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.200	Definitions
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-212.410	Best Available Control Technology (BACT) [PSD-FL-007]
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
^Rule 62-297.401	Compliance Test Methods
^Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 FEDERAL RULES

40 CFR 60	NSPS Subpart D
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. AIR POLLUTION CONTROL TECHNIQUES

The applicant proposes to control air pollutant emissions of SO_2 by restricting the maximum sulfur content of the fuel.

6.1 APPLICANT CONTROL TECHNOLOGY PROPOSAL

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED LIMIT
Sulfur Dioxide	Limit Maximum Sulfur Content, By Weight	1.05% Sulfur for Units 1 and 2 0.68% Sulfur for Units 4 and 5

7. SOURCE IMPACT ANALYSIS

An impact analysis was not required for this project because it is not subject to the requirements of PSD.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. The Department will issue a draft permit to the applicant that allows the combustion of coal/ briquette fuel mixture with a restriction in the maximum sulfur content of the mixture such that there will be no increase in future actual emissions of SO_2.

Edward J. Svec
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850/921-8985

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June XX, 1999

DRAFT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffery Pardue
Director, Environmental Services Department Director, Environmental Services Department
Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

Re: DEP File No. 0170004-006-AC, Modification of Permit No. 0170004-003-AC, PSD-FL-007
Crystal River Power Plant

The applicant, Florida Power Corporation, Crystal River Power Plant, applied on March 24, 1999, to the Department for a modification to air construction permit number 0170004-003-AC for its Crystal River Power Plant located west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The modification is to include a coal/briquette mixture as an allowable fuel in Crystal River Units 1,2,4, and 5. The briquettes will be blended with some of the regular coal supply and Florida Power Corporation states the sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

OPERATIONAL REQUIREMENTS

1. Hours of Operation: These emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

2. Fuel: The emissions units described above may combust a mixture of coal and coal briquettes. [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE)]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

3. Sulfur Limitation: The maximum sulfur content of the coal/ briquette mixture, averaged on an annual basis, shall not exceed the following:[Requested by Applicant in the application received March 24, 1999]

Emissions Unit No.	Emissions Unit Description	Average Percent Sulfur Limit, By Weight
001	Fossil Fuel Steam Generator (FFSG), Unit 1	1.05%
002	FFSG, Unit 2	1.05%
004	FFSG, Unit 4	0.68%
003	FFSG, Unit 3	0.68%

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

4. The permittee shall demonstrate compliance with the fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. See specific condition 3.
[Rule 62-213.440, F.A.C.]

DRAFT

5. Sulfur Dioxide - Fuel Sampling. The following fuel sampling and analysis program shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the fuel sulfur standard:
Determine and record the as-fired fuel sulfur content, percent by weight, for coal using appropriate ASTM methods such as, ASTM D2013-72, ASTM D3177-75, and ASTM D4239-85, or latest ASTM edition methods, to analyze a representative sample of coal following each fuel delivery.
b. Record daily the amount of coal fired, the density of each fuel, the Btu value, and the percent sulfur content by weight of each fuel.
c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.
[Rule 62-213.440, F.A.C.]

6. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

7. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
[Rule 62-213.440(1)(b)2.b., F.A.C.]

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

DRAFT

Howard L. Rhodes, Director
Division of Air Resources
Management

DRAFT

CERTIFICATE OF SERVICE

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

* W. Jeffrey Pardue, Florida Power Corporation
Mike Kennedy, Florida Power Corporation
Gerald Kissell, P.E., DEP, Southwest District
Hamilton S. Oven, P.E., DEP
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Clerk Stamp

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

DRAFT

__________________________ ____________________
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero

FROM: Ed Svec

DATE: May 19, 1999

SUBJECT: Florida Power Corporation Crystal River Power Plant Coal/Briquette Mixture

Attached for approval and signature is the DRAFT permit to construct, intent and technical evaluation for the above referenced project. This project includes limits on the maximum sulfur content, by weight and based on an annual average, of the coal/briquette mixture which result in no actual increase in emissions of sulfur dioxide.

I recommend your approval and signature.

Attachments

/es

3/24/99

Assumptions:

Units 1+2 fire total of 2,000,000 tons per year of coal

Units 1+2 Coal Sulfur = ~~0.68~~ 1.09 percent sulfur

~~Rct~~ Units 4+5 fire total of 4,000,000 tons per year of coal

Units 4+5 Coal Sulfur = 0.68 percent sulfur

5% sulfur retention in ash

Bunker C sulfur content = 2.8 percent sulfur

5% Bunker C in briquettes from 1, 2

20% briquettes in coal/briquette blend.

$$SO_2 \text{ emissions} = \frac{2 \times 10^6 \text{ ton coal}}{\text{year}} \times \frac{1.09 \text{ tons sulfur}}{100 \text{ ton coal}} \times \frac{2 \text{ tons potential } SO_2}{\text{ton sulfur}} \times \frac{.95 \text{ ton } SO_2 \text{ emitted}}{\text{ton } SO_2 \text{ potential}}$$

$= 41420$

~~When~~

~~Sulf~~

Sulfur content of briquettes $= 0.05(2.80) + 0.95(1.09) = 0.140 + 1.036$

$= 1.~~18~~6$ 1.10

Sulfur content of Coal/briquette blend $= (0.80)1.090 + 0.20(1.1~~76~~) = ~~.87~~ +$

$+.2352$

1.107

$2 \times 10^6 \times 1.107 \times 2 \times .95$

$= 42{,}066$

200 tpy

~~646~~ 646 tpy

~~200~~

100 tpy

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Bituminous coal**	
2. Source Classification Code (SCC): **1-01-002-02**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **156.3**	5. Maximum Annual Rate: **1,368,750**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **1.2**	8. Maximum Percent Ash: **9**
9. Million Btu per SCC Unit: **24**	
10. Segment Comment (limit to 200 characters): **1. Heat content based on 12,000 Btu/lb. 2. Maximum sulfur content based on SO2 emission limit of 2.1 lb/MMBtu; Condition of Certification for Units 4 and 5**	

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):
   Bituminous coal

2. Source Classification Code (SCC): **1-01-002-02**

3. SCC Units: **Tons burned**

4. Maximum Hourly Rate: **199.8**

5. Maximum Annual Rate: **1,750,200**

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: **1.2**

8. Maximum Percent Ash:

9. Million Btu per SCC Unit: **24**

10. Segment Comment (limit to 200 characters):
    1. Heat content based on 12,000 Btu/lb. 2. Maximum sulfur content based on SO2 emission limit of 2.1 lb/MMBtu; Condition of Certification for Units 4 and 5

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):

Bituminous coal

2. Source Classification Code (SCC): **1-01-002-02**

3. SCC Units: **Tons Burned**

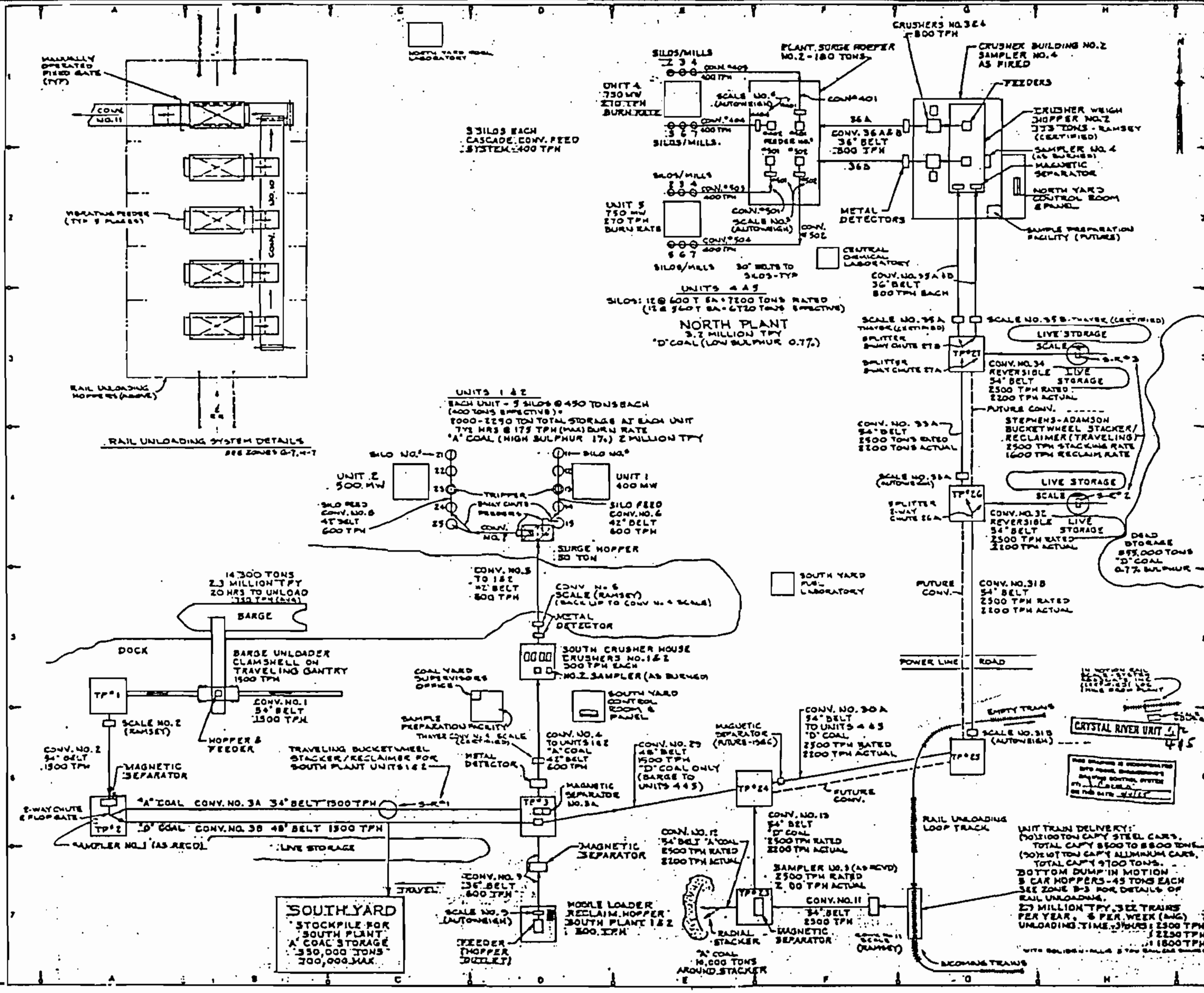
4. Maximum Hourly Rate: **277.7**	5. Maximum Annual Rate: **2,432,725**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.7**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **24**	

10. Segment Comment (limit to 200 characters):

1. Heat content based on 12,000 Btu/lb. 2. Maximum sulfur content based on SO2 emission limit of 1.2 lb/MMBtu; Condition of Certification for Units 4 and 5

Segment Description and Rate: Segment 2 of 2

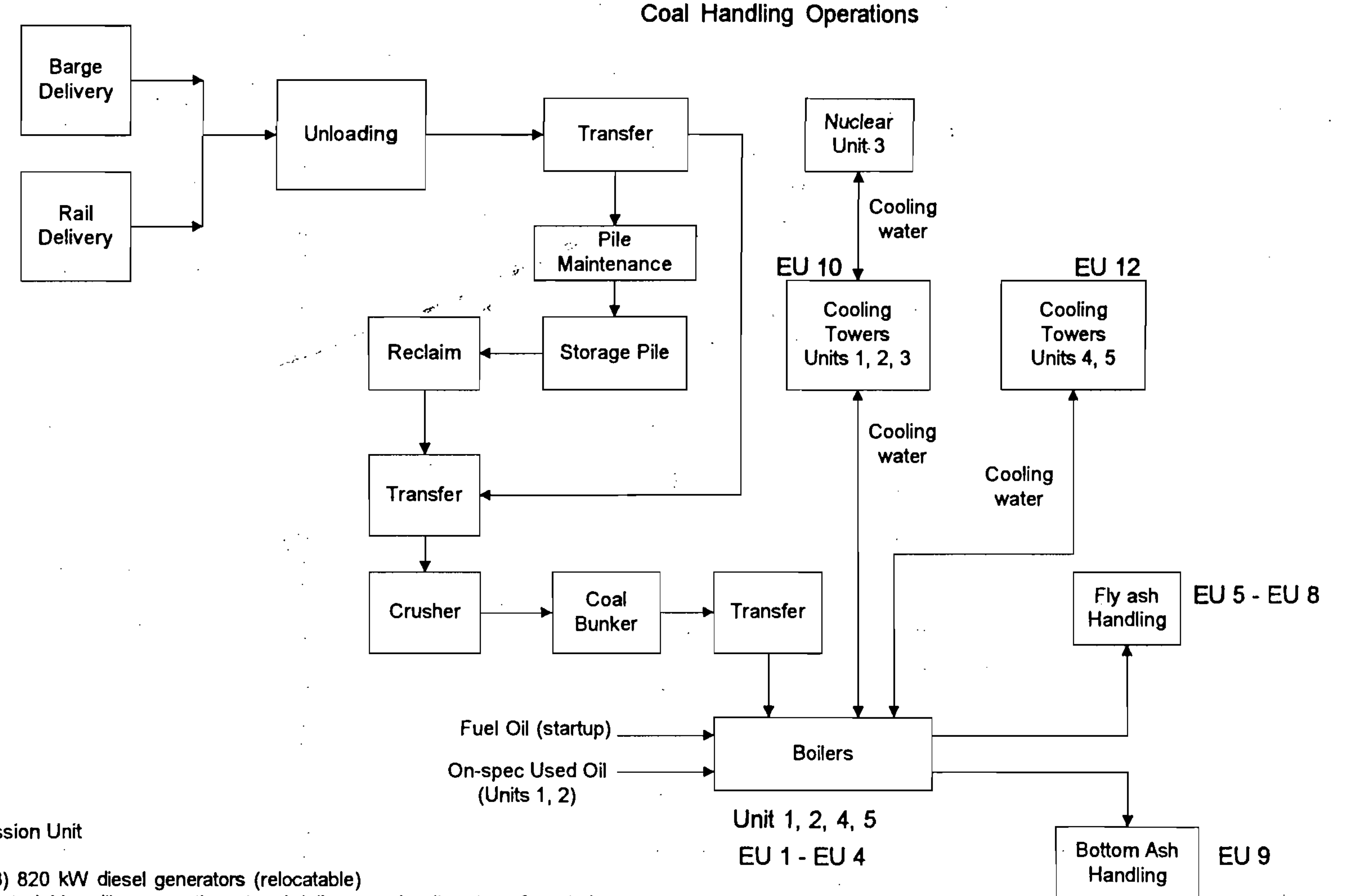
1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Bituminous coal**	
2. Source Classification Code (SCC): **10100202**	
3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **277.7**	5. Maximum Annual Rate: **2,433,725**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.7**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **24**	
10. Segment Comment (limit to 200 characters): **1. Heat content based on 12,000 Btu/lb. 2. Maximum sulfur content based on SO2 emission limit of 1.2 lb/MMBtu; Condition of Certification for Units 4 and 5**	



Schematic of FPC Crystal River Coal Handling System

KBN

Simplified Diagram
Coal Handling Operations



Note:
EU = Emission Unit

EU 11 - (3) 820 kW diesel generators (relocatable)
EU 13 - Material handling operations (coal delivery, unloading, transfer, etc.)
EU 14 - Facility-wide Fugitive Deminimis Emissions (not shown)

See segment section for operating rate of each emission unit.

Attachment
Facility Process Flow Diagram
Florida Power Corporation
Crystal River, FL

Process Flow Legend:
Solid / Liquid ——→
Gas – – – →
Steam ··········→

Emission Unit: Process Area: Boiler Unit 1, 2, 3, and 4
Filename: FPCCR2E.VSD
Latest Revision Date: 6/5/96

KBN Engineering and Applied Sciences, Inc.

drums where it is coked by its own contained heat. The process requires several drums to permit removal of the coke in one drum while the others remain on stream. The residual product which solidifies in these drums is termed *delayed coke*. When first removed from the drum, it has the appearance of run-of-mine coal, except that the coke is dull black.

The analysis of the coke varies with the crude from which it is made, ranging as follows:

Moisture	3–12%
Volatile matter	10–20%
Fixed carbon	71–88%
Ash	0.2–3.0%
Sulfur	2.9–5.4%
Btu/lb, dry	14,100–15,600 (32.8 to 36.3 MJ/kg)

FLUID COKING

Two large vessels are used in fluid coking. One is known as a reactor vessel, and the other, a burner vessel. In this process, fluid coke is both the catalyst and secondary product. The seed coke is first heated in the burner vessel, either by adding air and burning a portion of the coke, or by burning an extraneous fuel such as oil. The heated seed coke then flows into the reactor vessel where it comes in contact with the preheated residual oil and the lighter fractions of the oil are flashed off. The coke which is produced both deposits in uniform layers on the seed coke and forms new seed coke. Thus there is a constantly accumulating coke reservoir which is tapped off and is available as a boiler feed.

The coke thus formed is a hard, dry, spherical solid resembling black sand. It is composed of over 90-percent carbon with varying percentages of sulfur and ash, depending on the source of the crude oil. Typical analyses are

Fixed carbon	90–95%
Volatile matter	3–6.5%
Ash	0.2–0.5%
Sulfur	4.0–7.5%
HHV, Btu/lb, dry	14,100–14,600 (32.8 to 34.0 MJ/kg)

COAL TAR

Coal tar is a byproduct in the carbonization of coal. The tar compounds are extremely complex and number in the hundreds. The solid material which is insoluble in benzene is contained as colloidal and coarse dispersed particles and is known as "free carbon." The composition of the tar is dependent on the temperature of carbonization and, to a lesser extent, on the nature of the coking coal. The following is an example of a coal tar analysis.

Carbon	89.9%
Hydrogen	6.0%
Sulfur	1.2%
Oxygen	1.8%
Nitrogen	0.4%
Moisture	0.7%
Gravity, Baumé	1.18 °
Viscosity at 122°F, SSF	900
Flash point	156°F (69°C)
Heating Value, Btu/lb, dry	16,750 (39.0 MJ/kg)

Coal tar is burned in boilers only when it cannot be sold for other purposes at a higher price than its equivalent fuel value. At ordinary temperature, the viscosity of tar is very high and must be heated for pumping. It burns like a fuel oil and the same equipment can be used.

COAL TAR PITCH

Coal tar pitch is used to a small extent for generation of steam. It is the residue resulting from the distillation and refining of coal tar. The pitch is solid at ordinary atmospheric temperature but becomes liquid at about 300°F. Generally, it is burned in pulverized form; in a few cases, it is melted and burned like oil or coal tar. When it is burned in pulverized form, it must be kept cool during pulverization and during delivery to the furnace. In some cases, it is preferred to coal. Because of its very low ash content, the stack gas is practically free from dust, and therefore there is no flue dust nuisance. When burned in liquid form, it must be kept very hot to prevent congealing. Table VIII shows analyses of coal tar pitch.

Table VII. Analyses of Typical Cokes, as Fired

	% Proximate Analysis					% Ultimate Analysis					HHV,	A at Zero Excess Air,
	H_2O	VM	FC	ASH	H_2O	C	H_2	S	O_2	N_2	Btu/Lb	Lb/10^6 Btu
Kind												
High-temperature coke	5.0	1.3	83.7	10.0	5.0	82.0	0.5	0.8	0.7	10.0	12,200	798
Low-temperature coke	2.8	15.1	72.1	10.0	2.8	74.5	3.2	1.8	6.1	10.0	12,600	763
Beehive coke	0.5	1.8	86.0	11.7	0.5	84.4	0.7	1.0	0.5	11.7	12,527	807
Byproduct coke	0.8	1.4	87.1	10.7	0.8	85.0	0.7	1.0	0.5	10.7	12,690	802
High-temperature coke breeze	12.0	4.2	65.8	18.0	12.0	66.8	1.2	0.6	0.5	18.0	10,200	805
Gas Works Coke:												
Horizontal retorts	0.8	1.4	88.0	9.8	0.8	86.8	0.6	0.7	0.2	9.8	12,820	808
Vertical retorts	1.3	2.5	86.3	9.9	1.3	85.4	1.0	0.7	0.3	9.9	12,770	809
Narrow coke ovens	0.7	2.0	85.3	12.0	0.7	84.6	0.5	0.7	0.3	12.0	12,550	802

WOOD

Wood is a complex vegetable tissue composed principally of cellulose, an organic compound having a definite chemical composition. It would, therefore, seem reasonable to assume that equal weights of different dry wood species will have practically the same heat content. However, owing to the presence of resins, gums and other substances in varying amounts, heat content is not uniform.

Ultimate analyses showing the chemical composition of several different wood species are given in Table IX. Because the substances making up these fuels are complex organic chemical compounds, and complex thermodynamic changes take place when they are burned in a furnace, it is not possible to make use of formulas such as the Dulong type to predict their heating values. These analyses do not indicate the amount of resins or similar substances present. But note that the heat content, on the dry basis, is greatest in the cases of highly resinous woods as fir and pine.

The moisture content of freshly cut wood varies from 30 to 50 percent. After air drying for approximately a year, this is reduced to between 18 and 25 percent.

Table VIII. Coal Tar Pitch

Proximate Analysis	
Moisture	2.2%
VM	48.2%
FC	48.9%
Ash	0.7%
Ultimate Analysis	
Carbon	90.1%
Hydrogen	4.9%
Sulfur	0.9%
Oxygen	0.6%
Nitrogen	0.6%
Moisture	2.2%
Ash	0.7%
HHV, dry	16,200 (37.7 MJ/kg)

Most wood as commercially available for steam generation is usually the waste product resulting from some manufacturing process. Its moisture content as received at the furnace will depend on (1) extraneous water from source or storage or handling in the rain and (2) whether it is "sap wood" or "heart wood," as well as on the species and on the time of year it is cut.

Table XV. Detailed Requirements for Fuel Oils[A]

Grade of Fuel Oil	Flash Point, °C (°F) Min	Pour Point, °C (°F) Max	Water and Sediment Vol % Max	Carbon Residue on 10 % Bottoms % Max	Ash Weight % Max	Distillation Temp. C (°F) 10% Point Max	90% Point Min	90% Point Max
No. 1 Distillate oil intended for vaporizing pot-type burners and other burners requiring this grade	38 or legal (100)	−18[C] (0)	0.05	0.15	...	215 (420)	...	288 (550)
No. 2 Distillate oil for general purpose heating for use in burners not requiring No. 1	38 or legal (100)	−6[C] (20)	0.05	0.35	...	...	282[C] (540)	338 (640)
No. 4 Preheating not usually required for handling or burning	55 or legal (130)	−6[C] (20)	0.50	...	0.10	...	...	...
No. 5 (Light) Preheating may be required depending on climate and equipment	55 or legal (130)	...	1.00	...	0.10	...	...	...
No. 5 (Heavy) Preheating may be required for burning and, in cold climates, may be required for handling	55 or legal (130)	...	1.00	...	0.10	...	...	...
No. 6 Preheating required for burning and handling	60 (140)	[G]	2.00[E]	...	...	...	...	...

[A] It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless in fact it meets all requirements of the lower grade.

[B] In countries outside the United States other sulfur limits may apply.

[C] Lower or higher pour points may be specified whenever required by conditions of storage or use. When pour point less than −18°C (0°F) is specified, the minimum viscosity for Grade No. 2 shall be 1.8 cSt (32.0 SUS) and the minimum 90 % point shall be waived.

[D] Viscosity values in parentheses are for information only and not necessarily limiting.

[E] The amount of water by distillation plus the sediment by extraction shall not exceed 2.00 %. The amount of sediment by extraction shall not exceed 0.50 %. A deduction in quantity shall be made for all water and sediment in excess of 1.0 %.

[F] Where low sulfur fuel is required, fuel oil falling in the viscosity range of a lower numbered grade down to and including No. 4 may be supplied by agreement between purchaser and supplier. The viscosity range of the initial shipment shall be identified and advance notice shall be required when changing from one viscosity range to another. This notice shall be in sufficient time to permit the user to make the necessary adjustments.

[G] Where low sulfur fuel oil is required, Grade 6 fuel oil will be classified as low pour +15°C (60°F) max or high pour (no max.) Low pour fuel oil should be used unless all tanks and lines are heated.

Excerpted from *ASTM Standards* D 396, Specifications for Fuel Oils.

Table XV. **Detailed Requirements for Fuel Oils[A] — *Continued***

Saybolt Viscosity, s[D] Universal at 38°C (100°F)		Furol at 50°C (122°F)		Kinematic Viscosity, cSt[D] At 38°C (100°F)		At 50°C (122°F)		Specific Gravity 60/60°F (deg API)	Copper Strip Corrosion	Sulfur, %
Min	Max	Min	Max	Min	Max	Min	Max	Max	Max	Max
...	...	...	...	1.4	2.2	...	...	0.8499 (35 min)	No. 3	0.5 or legal
(32.6)	(37.9)	...	...	2.0[C]	3.6	...	...	0.8762 (30 min)	No. 3	0.5[B] or legal
(45)	(125)	...	...	5.8	26.4[F]	...	...	...	...	legal
(>125)	(300)	...	...	>26.4	65[F]	...	...	...	...	legal
(>300)	(900)	(23)	(40)	>65	194[F]	(42)	(81)	...	...	legal
(>900)	(9000)	(>45)	(300)	>92	638[F]	50°C	(122°F)	...	...	legal

tion and cracking, such fuels as gasoline, kerosene, gas oil, light fuel oils, lubricating oil, heavy fuel oil, residual tar, pitch and petroleum coke are produced.

PROPERTIES OF FUEL OIL

The term *fuel oil* may conveniently cover a wide range of petroleum products. It may be applied to crude petroleum, to a light petroleum fraction similar to kerosene or gas oil, or to a heavy residue left after distilling off the fixed gases, the gasoline, and more or less of the kerosene and gas oil. To provide standardization, specifications have been established, Table XV, for several grades of fuel oil.

Sometimes designated as light and medium domestic fuel oils, Grades No. 1 and No. 2 are specified mainly by the temperature of the distillation range. Grade No. 6, designated as heavy industrial fuel oil and sometimes known as Bunker C oil, is specified mainly by viscosity. The specific gravities of Grades 4, 5, and 6 are not specified because they will vary with the source of the crude petroleum and the extent of the refinery operation in cracking and distilling.

API, density in lb per gal, Btu per lb, and Btu per gal for petroleum products is graphically shown in Fig. 10. Also included are the ranges in deg API for gasoline, kerosene, gas oil and fuel oils. Knowing the value of any one of these characteristics, it is possible to determine all the others quickly. For example, assume the deg API to be 75, then the intersection of this value with the deg API curves is at a point A, through which a horizontal line is drawn to intersect the remaining curves. Then, by referring to their respective scales, it is possible to read the specific gravity B as 0.685, the density C as 5.675 lb per gal, and the higher heating value at D as 20,550 Btu per lb, or at E as 116,800 Btu per gal. Of particular interest is the fact that, although the high specific gravity fuel oils (15°API) have a lower heating value per pound than the lower specific gravity gasoline (60°API), the total heat per gallon, the basis on which they are purchased commercially, is considerably greater.

FLASH AND FIRE POINT

Flash point of fuel oil is the lowest temperature at which sufficient vapor is given off to

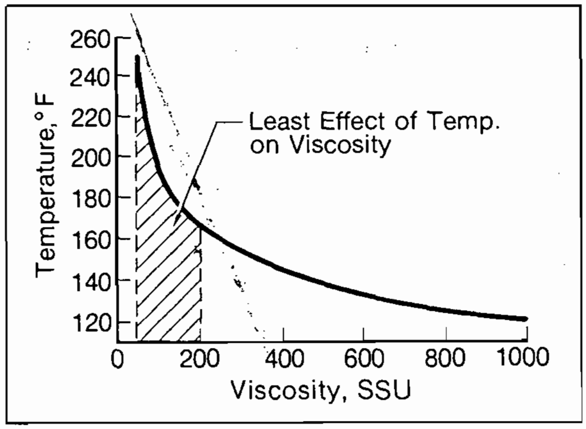


Fig. 8 **Viscosity versus temperature, No. 6 fuel oil**

Table XVI. Typical Analyses and Properties of Fuel Oils*

Grade	No. 1 Fuel Oil	No. 2 Fuel Oil	No. 4 Fuel Oil	No. 5 Fuel Oil	No. 6 Fuel Oil
Type	Distillate (Kerosene)	Distillate	Very Light Residual	Light Residual	Residual
Color	Light	Amber	Black	Black	Black
API gravity, 60°F	40	32	21	17	12
Specific gravity, 60/60°F	0.8251	0.8654	0.9279	0.9529	0.9861
Lb/U.S. gallon, 60°F	6.870	7.206	7.727	7.935	8.212
Viscos., Centistokes, 100°F	1.6	2.68	15.0	50.0	360.0
Viscos., Saybolt Univ., 100°F	31	35	77	232	...
Viscos., Saybolt Furol, 122°F	...	...	...	...	170
Pour point, °F	Below zero	Below zero	10	30	65
Temp. for pumping, °F	Atmospheric	Atmospheric	15 min.	35 min.	100
Temp. for atomizing, °F	Atmospheric	Atmospheric	25 min.	130	200
Carbon residue, %	Trace	Trace	2.5	5.0	12.0
Sulfur, %	0.1	0.4–0.7	0.4–1.5	2.0 max.	2.8 max.
Oxygen and nitrogen, %	0.2	0.2	0.48	0.70	0.92
Hydrogen, %	13.2	12.7	11.9	11.7	10.5
Carbon, %	86.5	86.4	86.10	85.55	85.70
Sediment and water, %	Trace	Trace	0.5 max.	1.0 max.	2.0 max.
Ash, %	Trace	Trace	0.02	0.05	0.08
Btu/gallon	137,000	141,000	146,000	148,000	150,000

* Courtesy Exxon Corporation

Florida Power
CORPORATION

RECEIVED

MAR 24 1999

BUREAU OF
AIR REGULATION

March 22, 1999

Mr. Al Linero, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

0170004-006-AC
PSD-FL-007

Re: Coal "Briquettes" Fuel

As we discussed in Tallahassee last week, I have enclosed a P.E. seal and application processing fee check for the "coal briquettes" permit application for the Florida Power Corporation (FPC) Crystal River plant. For your convenience, there are two originals of the P.E. seal page enclosed.

Thank you for your prompt processing of this request. Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

ONE POWER PLAZA, 263 - 13th Avenue South, BB1A, St. Petersburg, FL 33701-5511 •
P.O. Box 14042, BB1A • St. Petersburg • Florida 33733-4042 • (727) 866-5151
A Florida Progress Company

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [✓] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

3/23/99

Signature Date

Kent D. Hedrick

FL PE# 50474

(seal)

* Attach any exception to certification statement.

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [✓] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Kent D. Hedrick 3/23/99 Kent D. Hedrick

Signature Date

FL PE # 50474

(seal)

* Attach any exception to certification statement.

Florida Power
CORPORATION

February 22, 1999

Mr. Al Linero, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Coal "Briquettes" Fuel

As you know from previous correspondence, Florida Power Corporation (FPC) has been approached by its fuel supplier, Electric Fuels Corporation, concerning the possibility of burning "coal briquettes" at its Crystal River plant. The briquettes are produced from coal fines at the mines that currently supply the coal for Crystal River Units 1, 2, 4, and 5. Coal fines are combined under heat and pressure with a small amount of oil (maximum of 5% Bunker C oil) at the mine. The oil is the binding agent for the coal fines. Subjecting the coal fines to heat and pressure removes moisture and produces the coal briquettes, which are small chunks of coal that can be handled and burned with the regular coal supply.

The following table shows the average sulfur content of the coal supplies burned in Units 1 and 2, and in Units 4 and 5. The averages are based on daily coal samples averaged over the calendar year and have been reported in the Annual Operating Reports for these units.

	1996	1997	1998	Average
Units 1 and 2	1.03%	1.07%	1.05%	1.05%
Units 4 and 5	0.68%	0.67%	0.69%	0.68%

FPC would receive the briquettes in shipments blended with some of the regular coal supply. In order to ensure that the addition of coal briquettes does not result in an increase in emissions due to the sulfur content of the Bunker C oil, FPC is willing to commit to limiting the sulfur content of these shipments. The sulfur content, as averaged on an annual basis, of the shipments of briquettes combined with coal, will not exceed 1.05% for Units 1 and 2, and will not exceed 0.68% for Units 4 and 5.

Use of the briquettes as fuel is an environmentally beneficial way of utilizing the coal fines resulting from the mining process. If not used as fuel, the fines would otherwise be discarded. Limiting the sulfur content of the fuel to historical levels ensures that no emissions increase will result.

FPC requests that the DEP add "coal briquettes" to the list of fuels authorized to be burned in units 1, 2, 4, and 5, subject to the sulfur content limitation. This limit would apply to the annual average sulfur content of the shipments received of briquettes combined with coal. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services
FPC Responsible Official

Florida Power CORPORATION

ACCOUNTS PAYABLE DEPT. CX1K
P. O. BOX 14042
ST. PETERSBURG, FL 33733-4042
(727) 820-5257

REMITTANCE ADVICE

CHECK DATE 03/17/1999 VENDOR FLA DEPT OF ENVIRONMENTAL VENDOR NO. 278473 CHECK NO. 2048363

INVOICE NO.	DATE	OUR ORDER NO.	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
CK127745	03/12/99		9903161352	250.00	.00	250.00
					TOTAL	250.00

THE ATTACHED REMITTANCE IS IN FULL SETTLEMENT OF ACCOUNT AS STATED. IF NOT CORRECT PLEASE RETURN TO ABOVE ADDRESS.

Accounts Payable Department CX1K
P.O. Box 14042
St. Petersburg, Fl 33733-4042

Florida Power CORPORATION

63-115
631

DATE 03/17/1999 CHECK NO. 2048363

PAY: $250*DOLLARS AND 00 CENTS $*******250.00

SunTrust / Mid-Florida

Void after 60 days

TO THE ORDER OF
FLA DEPT OF ENVIRONMENTAL
PROTECTION
2600 BLAIR STONE RD
TALLAHASSEE FL 32399-2400

Pamela A. Saari
Treasurer

[redacted]

Florida Power
CORPORATION

RECEIVED

MAR 17 1999

BUREAU OF
AIR REGULATION

March 15, 1999

Mr. Clair Fancy, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Petroleum Coke Permitting

As you know, a final construction permit authorizing a blend of coal and petroleum coke to be burned in Florida Power Corporation's (FPC) Crystal River Units 1 and 2 was issued by the DEP on January 11, 1999. FPC requests that the conditions authorizing use of the blended fuel be incorporated into the Title V permit for these units.

In addition, the DEP is currently reviewing FPC's submittal to allow use of "coal briquettes" in Crystal River Units 1, 2, 4, and 5. FPC understands that approval is forthcoming, pending receipt of a $250 processing fee. Therefore, FPC also requests that the Title V permit also reflect this approval at the appropriate time.

Thank you for your consideration of these requests. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director

ONE POWER PLAZA, 263 - 13th Avenue South, BB1A, St. Petersburg, FL 33701-5511 •
P.O. Box 14042, BB1A • St. Petersburg • Florida 33733-4042 • (727) 866-5151
A Florida Progress Company

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 30, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffrey Pardue, Director
Environmental Services Department
Florida Power Corporation
Post Office Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

Re: DEP File No. 01740004-004-AV
Crystal River Units 1, 2, 4, and 5
Coal Fines Briquettes

Dear Mr. Pardue:

Following receipt of your letter of September 28, 1998, we verbally requested additional information related to the briquettes that FPC intends to burn at the Crystal River coal-fired units. This information includes P.E. certification that there will not be an increase in emissions, the binder (oil) analysis, and a statement that there will be no equipment or operational changes.

On October 20, the matter was discussed at greater length. Following are our additional comments:

1. Our information on the sulfur content of 'Bunker C' indicates that the maximum specification for international maritime use is 5 percent (%). A typical maximum content per the Combustion Engineering book is 2.8%.
2. A simple calculation indicates that the typical sulfur concentration of the briquettes will be 1.176% compared with 1.09% (per your letter) for the typical bulk coal used in Crystal River Units 1 and 2. When burning 20% briquettes, the bulk sulfur concentration of the fuel burned will be approximately 1.107%. This assumes that the briquettes include 5% of Bunker C (at 2.8% sulfur).
3. The small increase in sulfur concentration is equal to an annual increase of approximately 650 tons of sulfur dioxide (SO_2) per year from Crystal River Units 1 and 2 combined. This assumes that the plants actually burn roughly 2,000,000 tons per year of coal combined.
4. A similar estimate for Units 4 and 5, assuming they burn 4,000,000 tons per year of coal (combined) indicates an increase of about 1,600 tons per year of SO_2 when burning a stream of 20% briquettes.

5. Please obtain from the supplier a more accurate estimate of the average sulfur content of the Bunker C to be used in making the briquettes as well as a better estimate of the amount of Bunker C actually required to bind the fines.
6. It is possible that by using less Bunker C of a somewhat lower sulfur concentration, that emissions increases can be minimized.
7. In the case of Crystal River 1 and 2, it would appear to be simple, and fairly inexpensive, to add enough of the lower sulfur (Unit 4 and 5) coal to compensate for the increases from the briquettes. It may also be possible to burn enough of the Unit 4 and 5 coal in Units 1 and 2 to compensate for all of the increase in SO_2 from the briquettes used in all units.
8. It may be possible to inject a small amount of lime into the ducts to offset the increase.
9. There could be other potential binders locally available, such as coal tar or pitch, which may (or may not) have a lower sulfur concentration than the available Bunker C. Obviously, the quantities would need to be small and the leaching characteristics (compared to the coal) known.

Attached is a list of recent awards by the Department of Energy for projects similar to the one planned by FPC. The use of the fines can help ameliorate a water pollution problem in coal mining areas. We expect to receive various papers from DOE shortly and will share them with you. We believe that the increase in emissions can be minimized by obtaining more detailed information from the briquette supplier and by considering a few available options that are probably cost-effective. The above information will allow us to determine if any applications are required.

If you have any questions regarding this matter, please call me, Scott Sheplak, or Al Linero at (850)488-0114.

Sincerely,

Al Linero, P.E. 12/30

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

CHF/aal

Enclosures

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. W. Jeffrey Pardue, Director
Environmental Services Dept.
Florida Power Corporation
P. O. Box 14042, MAC BBIA
Saint Petersburg, FL 33733-4042

4a. Article Number
P 263 584 898

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

7. Date of Delivery NOV 02 1998

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994 Domestic Return Receipt

Thank you for using Return Receipt Service.

P 263 584 898

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Mr. W. Jeffrey Pardue, Director
Environmental Services Dept.
Florida Power Corporation
P. O. Box 14042, MAC BBIA
Saint Petersburg, FL 33733-4042

Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 10-30-98	

PS Form **3800**, April 1995

U.S. Department of Energy

DOE Fossil Energy TECHLINE

Issued on August 12, 1998

DOE Selects R&D Projects to Study Advanced Concepts For Producing Clean Fuels and Feedstocks from Coal

Discarded Coal, Biomass/Solid Wastes Offer Future Fuel Sources; Research Also Focusing on Air Toxics Removal

For decades the brackish impoundments at many of the nation's coal cleaning plants have been treated as their name implies — as coal *waste* ponds. Similarly, most of the 20 million tons of plastics, 250 million rubber tires, and 33 million barrels of waste oil Americans discard each year are left to degrade in landfills or other disposal sites.

But to the Department of Energy's Office of Fossil Energy and several of the nine winning proposers selected this week in the department's *"Solid Fuels and Feedstocks Grand Challenges* " competition, these discarded wastes offer potentially huge, largely untapped sources of clean, affordable energy.

Four of the projects announced today propose innovative methods for recovering useable fuels from materials that otherwise would be discarded at coal cleaning plants or utility power stations. Another four will develop technologies that combine coal and biomass or municipal solid waste into clean-burning fuels. The ninth will study a method for removing mercury from coal before it is burned, preventing the mercury from being released to form a hazardous air pollutant.

The department's Federal Energy Technology Center in Pittsburgh, PA, and Morgantown, WV, ran the competition. The nine projects were selected from 30 that submitted proposals. Once contracts are negotiated and awarded, the winning proposers will begin the initial phase of a two-phase research and development program.

Initially, the proposed concepts will be developed at laboratory scales in projects lasting up to 18 months. The department will provide $300,000 to $500,000 for each initial award, and the selected proposer must match at least 20 percent of the federal funding.

Proposers selected for the second phase will receive federal support to scale up and test their technologies in a "proof-of-concept" integrated facility. Energy Department awards for the second phase could range from $500,000 to $1 million for up to three years, and the private sector cost-sharing must meet or exceed the government's share.

Recovering Carbon from Coal Wastes

An estimated 2 to 3 billion tons of coal "fines" — microscopic coal particles — lie in waste impoundments at coal mines and washing plants around the country. This discarded "waste" contains the energy equivalent of 8 to 12 billion barrels of oil, comparable to a "super giant" oil field. Moreover, each year, mining operations dispose of as much as 30 million tons of coal as waste, and utilities discard millions of tons of unburned carbon along with fly ash in power plant landfills.

Four of the projects announced today by the Department of Energy will develop advanced technologies to recover useable fuels from these waste products:

- **Pennsylvania State University**, University Park, PA
  Ultrasonically-Enhanced Dense-Medium Cycloning for Fine Coal and Coal Refuse Impoundment Materials
  Contact: Dr. Mark S. Klima, Associate Professor of Mineral Processing, (814)863-7942

  This project will investigate the application of ultrasonic energy to scrub clays from the surfaces of particles and increase particle dispersion both for the improved cleaning and recovery of coal from waste ponds using dense-medium (magnetite) cycloning and the improved performance of the dense-medium recovery systems. Magnetite (an iron ore) is used to create a heavy liquid to facilitate density-based separations.

- **Southern Illinois University**, Carbondale, IL
  Development and Demonstration of Integrated Carbon Recovery Systems from Fine Coal Processing Waste
  Program Manager: R.Q. Honaker, Associate Professor
  Contact: John S. Jackson III (618)453-4534

  This project is to develop a suite of new/improved density-based and surface-based fine-coal cleaning devices and fine-coal dewatering techniques to improve the recovery, economics, and marketing of fine coal that is either currently being rejected from continuing operations or was previously wasted to coal impoundments.

- **Virginia Polytechnic Institute and State University**, Blacksburg, VA
  Advanced Carbon Recovery/Dewatering Systems Development
  Project Director: Roe-Hoan Yoon
  Contact: Tom Hurd (540)231-5281

  This project will investigate a number of innovative fine-coal dewatering technologies to improve the ability to handle and market economical fine coal recovery and utilization systems. These technologies under development will be applicable to fines recovered from both coal ponds and existing production.

- **University of Kentucky Research Foundation**, Lexington, KY
  A Technology for the Recovery of High Quality Fuel and Adsorbent Carbons from Coal Burning Utility Ash Ponds and Landfills
  Contact: Penny Allen (606)257-9424

  This project is aimed at developing water-based processes to recover carbon from power plant fly ash for use either as a fuel for refiring at the utility or as a high-quality carbon adsorbent. The technology also produces a high-quality, salable fly ash from previously unmarketable material.

Combining Coal with Biomass/Waste

"Biofuels" — a diverse group of energy sources ranging from wood and agribusiness wastes to fast-growing "energy crops" — have long been used to generate steam and electricity for industrial factories and processing plants. Recently, however, utilities and other power generators have become interested in co-firing these fuels with coal to reduce fuel costs and lower greenhouse gas emissions. (When biomass is burned as fuel, its carbon is recycled back into the atmosphere at roughly the same rate at which the original plant material removed it; thus biomass makes little, if any, net contribution to the pool of carbon dioxide in the air.)

Also, nearly half of all the landfill materials (municipal and animal waste, plastics, rubber, etc.) discarded in the United States potentially have some energy value; yet, only a small portion is recycled. For example only 8 million of the 33 million barrels of waste oil disposed of each year is reused. Likewise, less than half of the 250 million rubber tires Americans discard each year are recycled.

Four of the selected proposers will focus on technologies that mix these biomass or waste products with coal to form low-cost, clean-burning fuels:

- **Altex Technologies Corporation**, Santa Clara, CA
  A Low-Cost and High-Quality Solid Fuel from Biomass and Coal Fines
  Contact: Mehdi Namazian (408)982-2303

  This project is for the development of an integrated dewatering and extrusion device for pelletizing biomass and coal using sewage sludge as a binder and sealer. The resultant pellets are weather-proof and have superior transportability characteristics.

- **CQ Inc.**, Homer City, PA
  Production of New Biomass/Waste-Containing Solid Fuels
  Contact: David J. Akers, Vice President (724)479-3503

  This project is for the development of a novel die for pellet mills that facilitates the removal of excess moisture from various feeds to produce strong, weather-proof, and transportable composite fuels consisting of different combinations of biomass, waste, and coal. The technology is an extension of the commercially-applied E-Fuel technology developed by the proposer.

- **University of Missouri**, Columbia, MO
  Compacting Biomass and Municipal Solid Wastes to Form an Upgraded Fuel
  Contact: Richard Otto (573)882-7560

  This project is for the development of a rotary press for dewatering and compacting biomass into logs for various types of combustion applications. The technology is an adaptation of the coal log technology developed by the proposer.

- **McDermott Technology, Inc.**, Alliance, OH
  New Solid Fuels from Coal and Biomass Waste
  Program Manager: Hamid Farzan
  Contact: Karl W. Boettger (330)829-7430

  This project is for the development of a technology for the drying and pelletizing of municipal sewage sludge and paper sludge both with and without the addition of coal to produce pellets for co-firing in a cyclone boiler. Any toxics present in the sludges become encased in the slag produced by the cyclone boiler.

Removing Air Toxic Impurities

The Environmental Protection Agency is in the final stages of gathering information to determine whether mercury emissions from power plants should be regulated. Mercury is one of more than one hundred substances classified as a "hazardous air pollutant." In coal, mercury exists in trace amounts within the carbon latticework that makes up coal's complex structure. When the coal is burned, mercury is converted to gaseous form which may be much more difficult to capture. Removing it prior to combustion, therefore, may be the most cost-effective approach if future controls are mandated.

The ninth project selected by the Energy Department will develop an innovative approach to remove mercury from coal before it is burned:

- **EXPORTech Company, Inc.**, New Kensington, PA
  Removal of Selected Hazardous Air Pollutant Precursors by Dry Magnetic Separation
  Contact: Robin F. Oder (724) 337-4415

  This project proposes to develop a technology for the pre-combustion removal of mercury from coal using dry magnetic separation on pulverizer recycle streams at pulverized-coal power plants. The process is applicable to both cleaned and uncleaned coals and removes mercury via its association with pyrite that is liberated during the pulverization process.

Projects Reflect a Redirection of DOE's Coal Preparation R&D

The nine projects selected for negotiations represent a new direction for the coal preparation research historically carried out by the Federal Energy Technology Center, the coal research arm of the Energy Department's fossil energy program. The past program was oriented largely on developing improved coal cleaning technologies to remove potential pollutants from coal. While pollutant removal is still a key part of the effort, the new program has been renamed the "Solid Fuels and Feedstocks Program" to reflect its expanded research role in biomass/waste coprocessing, premium carbon products from coal, and the production of tailored feedstocks for industrial processes, residential use, chemicals, and transportation fuels.

-- End of *TechLine* --

For more information, contact:

Hattie Wolfe, DOE Office of Fossil Energy, 202/586-6503, e-mail: hattie.wolfe@hq.doe.gov

Otis Mills, DOE Federal Energy Technology Center, 412/892-5890, e-mail: mills@fetc.doe.gov

Technical Contact: Carl Maronde, DOE Federal Energy Technology Center, 412/892-6246, e-mail: marond@fetc.doe.gov

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Florida Power
CORPORATION

September 28, 1998

Mr. Clair Fancy, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Coal "Briquettes" Fuel

As you discussed with Mike Kennedy last week, Florida Power Corporation (FPC) has been approached by its fuel supplier, Electric Fuels Corporation, concerning the possibility of burning "coal briquettes" at its Crystal River plant. The briquettes are produced from coal fines at the mines that currently supply the coal for Crystal River Units 1, 2, 4, and 5. Coal fines are combined under heat and pressure with a small amount of oil (maximum of 5% Bunker C oil) at the mine. The oil is the binding agent for the coal fines. Subjecting the coal fines to heat and pressure removes moisture and produces the coal briquettes, which are small chunks of coal that can be handled and burned with the regular coal supply.

Attachment 1 contains laboratory analyses of the coal supply for Units 1 and 2 and of an 80%/20% blend of coal and coal briquettes. The coal analysis represents the average coal delivered in 1997. Attachment 2 contains the same comparison for the low-sulfur fuel that is burned in Units 4 and 5. Note that since the briquettes are produced from the same coal supply as that being burned in the Crystal River units, the analyses are virtually identical. Therefore, burning the coal briquettes in Crystal River Units 1, 2, 4, and 5 will not result in an increase in air pollutant emissions.

As discussed in your meeting with Mr. Kennedy, since the Crystal River units are currently permitted to burn coal, oil, and used oil, and the coal briquettes are produced from coal fines at the mine from the same coal supply, FPC requests that the DEP add "coal briquettes" to the list of fuels authorized to be burned in units 1, 2, 4, and 5. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services
FPC Responsible Official

Attachment 1

Units 1 and 2 Fuel Supply Analysis

Electric
Fuels
Corporation

Coal Analysis Report - Steam Coal

Electric Fuels Corporation

September 1998

Typical FPC "A" Quality
(Based on 1997 Deliveries)

Proximate Analysis

	As Received	Dry Basis
Moisture, %	6.56	***
Ash, %	8.49	9.09
Volatile Matter, %	35.43	37.92
Fixed Carbon, %	49.52	52.99
Sulfur, %	1.09	1.17
Btu/lb.	12691	13582

MAF Btu	14940
SO2/MBtu	1.72

Ultimate Analysis

	As Received	Dry Basis
Carbon, %	71.11	76.10
Hydrogen, %	4.72	5.05
Nitrogen, %	1.35	1.45
Oxygen, %	6.68	7.14
Chlorine, %	0.11	0.12

Sulfur Forms

	As Received	Dry Basis
Sulfate	0.01	0.01
Pyritic	0.41	0.45
Organic	0.67	0.71

Mineral Ash Analysis

	Ignited Basis
SiO2	52.70
Al2O3	29.00
Fe2O3	9.20
MgO	1.10
CaO	1.80
K2O	2.10
Na2O	0.46
TiO2	1.30
P2O5	0.30
SO3	1.30
Undetermined	0.75
Base/Acid Ratio	0.18
Slagging Index	0.21
Fouling Index	0.08
Silica Value	81.33
T250 Temperature	2875

Ash Fusion Temperatures

Degrees Fahrenheit

	Reducing	Oxidizing
Initial Deformation	2610	2700 +
Softening	2690	2700 +
Hemispherical	2700 +	2700 +
Fluid	2700 +	2700 +

Hardgrove Grindability Index	43

This analysis is for informational purposes only and is not intended to represent contractual guarantees.

Analyses provided are typical average values.

Electric
Fuels
Corporation

Coal Analysis Report - Steam Coal

Electric Fuels Corporation

September 1998

Proprosed "A" Quality
(Based on 1997 Quality blended including 200,000 of coal briquettes)

Proximate Analysis

	As Received	Dry Basis
Moisture, %	6.55	***
Ash, %	8.48	9.07
Volatile Matter, %	35.48	37.97
Fixed Carbon, %	49.48	52.96
Sulfur, %	1.09	1.17
Btu/lb.	12696	13586
MAF Btu	14941	
SO2/MBtu	1.72	

Ultimate Analysis

	As Received	Dry Basis
Carbon, %	71.12	76.11
Hydrogen, %	4.72	5.06
Nitrogen, %	1.35	1.45
Oxygen, %	6.69	7.14
Chlorine, %	0.11	0.12

Sulfur Forms

	As Received	Dry Basis
Sulfate	0.01	0.01
Pyritic	0.41	0.45
Organic	0.67	0.71

Mineral Ash Analysis

	Ignited Basis
SiO2	52.71
Al2O3	29.01
Fe2O3	9.20
MgO	1.10
CaO	1.60
K2O	2.10
Na2O	0.45
TiO2	1.30
P2O5	0.30
SO3	1.30
Undetermined	0.73
Base/Acid Ratio	0.18
Slagging Index	0.21
Fouling Index	0.08
Silica Value	81.33
T250 Temperature	2876

Ash Fusion Temperatures

Degrees Fahrenheit

	Reducing	Oxidizing
Initial Deformation	2610	2700 +
Softening	2690	2700 +
Hemispherical	2700 +	2700 +
Fluid	2700 +	2700 +

Hardgrove Grindability Index 43

This analysis is for informational purposes only and is not intended to represent contractual guarantees.

Analyses provided are typical average values.

Attachment 2

Units 4 and 5 Fuel Supply Analysis

Electric
Fuels
Corporation

Coal Analysis Report - Steam Coal

Electric Fuels Corporation

September 1998

Typical FPC "D" Quality
(Based on 1997 Deliveries)

Proximate Analysis

	As Received	Dry Basis
Moisture, %	7.78	***
Ash, %	9.17	9.94
Volatile Matter, %	33.09	35.86
Fixed Carbon, %	49.96	54.18
Sulfur, %	0.68	0.74
Btu/lb.	12430	13479

MAF Btu	14966
SO2/MBtu	1.09

Ultimate Analysis

	As Received	Dry Basis
Carbon, %	69.90	75.80
Hydrogen, %	4.61	5.00
Nitrogen, %	1.34	1.45
Oxygen, %	6.52	7.07
Chlorine, %	0.11	0.12

Sulfur Forms

	As Received	Dry Basis
Sulfate	0.01	0.01
Pyritic	0.11	0.12
Organic	0.56	0.61

Mineral Ash Analysis

	Ignited Basis
SiO_2	56.50
Al_2O_3	28.60
Fe_2O_3	5.40
MgO	1.20
CaO	1.80
K_2O	2.20
Na_2O	0.45
TiO_2	1.40
P_2O_5	0.30
SO_3	1.40
Undetermined	0.75
Base/Acid Ratio	0.13
Slagging Index	0.09
Fouling Index	0.06
Silica Value	87.06
T250 Temperature	2950

Ash Fusion Temperatures

Degrees Fahrenheit

	Reducing	Oxidizing
Initial Deformation	2690	2700 +
Softening	2700 +	2700 +
Hemispherical	2700 +	2700 +
Fluid	2700 +	2700 +

Hardgrove Grindability Index 42

This analysis is for informational purposes only and is not intended to represent contractual guarantees.

Analyses provided are typical average values.

Electric
Fuels
Corporation

Coal Analysis Report - Steam Coal

Electric Fuels Corporation

September 1998

Proposed FPC "D" Quality
(Based on 1997 Déliveries including 400,000 tons of coal briquettes)

Proximate Analysis

	As Received	Dry Basis
Moisture, %	7.77	***
Ash, %	9.16	9.93
Volatile Matter, %	33.14	35.93
Fixed Carbon, %	49.93	54.14
Sulfur, %	0.68	0.74
Btu/lb.	12435	13483

MAF Btu	14969
SO2/MBtu	1.09

Ultimate Analysis

	As Received	Dry Basis
Carbon, %	69.92	75.81
Hydrogen, %	4.62	5.01
Nitrogen, %	1.34	1.45
Oxygen, %	6.51	7.06
Chlorine, %	0.11	0.12

Sulfur Forms

	As Received	Dry Basis
Sulfate	0.01	0.01
Pyritic	0.11	0.12
Organic	0.56	0.61

Mineral Ash Analysis

	Ignited Basis
SiO_2	56.51
Al_2O_3	28.60
Fe_2O_3	5.40
MgO	1.20
CaO	1.80
K_2O	2.20
Na_2O	0.45
TiO_2	1.40
P_2O_5	0.30
SO_3	1.40
Undetermined	0.74

Base/Acid Ratio	0.13
Slagging Index	0.09
Fouling Index	0.06
Silica Value	87.06
T250 Temperature	2950

Ash Fusion Temperatures

Degrees Fahrenheit

	Reducing	Oxidizing
Initial Deformation	2690	2700 +
Softening	2700 +	2700 +
Hemispherical	2700 +	2700 +
Fluid	2700 +	2700 +

Hardgrove Grindability Index 42

This analysis is for informational purposes only and is not intended to represent contractual guarantees.

Analyses provided are typical average values.